Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Sections 14(1), 14(2), 14(3), 14(4)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

Section 14(1)

- *Full name, mailing address, and e-mail address of applicant.*
- *A reference to the particular provision of law requiring Commission approval.*

Section 14(2)

- *If applicant is a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state whether it is authorized to transact business in Kentucky.*

Section 14(3)

- *If applicant is a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state whether it is authorized to transact business in Kentucky.*

Section 14(4)

- *If applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, or a written statement that its partnership agreement and all amendments have been filed with the Commission in a prior proceeding and a reference to the case number of that proceeding.*

Response:

Section 14(1)
See Application Paragraph Nos. 1, 6, 16, and 25.

Section 14(2)
See Application Paragraph No. 3 and attached Certificate.

Section 14(3)
LG&E is not a limited liability company and, therefore, compliance with this filing requirement is not necessary.

Section 14(4)
LG&E is not a limited partnership and, therefore, compliance with this filing requirement is not necessary.

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 182432
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

LOUISVILLE GAS AND ELECTRIC COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is July 2, 1913 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 31st day of October, 2016, in the 225th year of the Commonwealth.

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
182432/0032196

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(1)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A statement of the reason the adjustment is required.

Response:

See Application.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(2)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that a certificate is not necessary.

Response:

The legal name of LG&E is Louisville Gas and Electric Company. It has never done business in any state under an assumed name and has never filed a Certificate of Assumed Name as may be required by KRS 365.015. Therefore, the filing of a copy of any such certificate as required by this Filing Requirement is not necessary.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(3)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

See attached.

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In the nine counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **RS**
Residential Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase secondary delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff.

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.04790	$0.03681	$0.08471	**R**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month’s charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Energy shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Energy and RTOD-Demand combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule GS (where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge per month:	$22.00	**T/I**
Plus an Energy Charge per kWh:		**T**
Off-Peak Hours:	$0.05850	**T/R**
On-Peak Hours:	$0.23263	**T**

ADJUSTMENT CLAUSES **T**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

T

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

Louisville Gas and Electric Company

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Demand shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Demand and RTOD-Energy combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule GS (where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge per month:	$22.00	**T/I**
Plus an Energy Charge per kWh:	$ 0.03681	**T/R**
Plus a Demand Charge per kW:		**T**
Base Hours:	$ 3.51	**T/I**
Peak Hours:	$ 7.68	**T/R**

ADJUSTMENT CLAUSES **T**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October

	Base	Peak	
Weekdays	All Hours	1 PM - 5 PM	T
Weekends	All Hours		

T

All Other Months of November continuously through March

	Base	Peak	
Weekdays	All Hours	7 AM - 11 AM	T
Weekends	All Hours		

T

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

DUE DATE OF BILL

Customer’s payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month’s charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate will not be eligible for Company’s Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION

To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief; **T**
2) having at least one firefighting apparatus; and **T**
3) half the members must be volunteers.

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.04790	$0.03681	$0.08471	**R**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **GS**
General Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. Electric No. 6, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

Basic Service Charge per month:	$31.50 single-phase service			**T/I**
	$50.40 three-phase service			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.06509	$0.03721	$0.10230	**I**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF LOAD **T**
Service hereunder will be metered except when, by mutual agreement of Company and Customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

DETERMINATION OF MAXIMUM LOAD T

If Company determines based on Customer's usage history that Customer may be exceeding the maximum load permitted under Rate GS, Company may, at its discretion, equip Customer with a meter capable of measuring demand to determine Customer's continuing eligibility for Rate GS. If Customer is equipped with a demand-measuring meter, Customer's load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE

The Basic Service Charge shall be the Minimum Charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

	Secondary	Primary	
Basic Service Charge per month:	$90.00	$240.00	**I**
Plus an Energy Charge per kWh:	$ 0.04071	$ 0.03925	**T**
Plus a Demand Charge per kW:			**T**
Summer Rate:			
(Five Billing Periods of May through September)	$20.93	$18.64	**I**
Winter Rate:			
(All other months)	$18.19	$15.96	**I**

Where the monthly billing demand is the greater of:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) if applicable, a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in Percent)}}$$

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Contracts under this rate shall be for an initial term of one (1) year, remaining in effect from month to month thereafter until terminated by notice of either party to the other.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Standard Rate **TODS**
Time-of-Day Secondary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for secondary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum loads exceed 250 kW and whose 12-month-average monthly maximum loads do not exceed 5,000 kW.

RATE

Basic Service Charge per month:	$200.00	**T**
Plus an Energy Charge per kWh:	$ 0.04049	**T**
Plus a Maximum Load Charge per kW:		**T**
Peak Demand Period:	$ 7.56	**T/I**
Intermediate Demand Period:	$ 5.54	**T/I**
Base Demand Period:	$ 4.84	**T/I**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **TODP**
Time-of-Day Primary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$330.00	**I**
Plus an Energy Charge per kWh:	$ 0.03824	**T**
Plus a Maximum Load Charge per kVA:		**T**
Peak Demand Period:	$ 6.86	**T/I**
Intermediate Demand Period:	$ 5.03	**T/I**
Base Demand Period:	$ 3.18	**T/I**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Standard Rate **RTS**

Retail Transmission Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for transmission service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$1,400.00		**I**
Plus an Energy Charge per kWh:	$	0.03711	**T**
Plus a Maximum Load Charge per kVA:			**T**
Peak Demand Period:	$	6.98	**T/I**
Intermediate Demand Period:	$	5.12	**T/I**
Base Demand Period:	$	1.52	**T/I**

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or

b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**

c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **FLS**
Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service FLS schedule of Kentucky Utilities Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$ 330.00	$1,400.00	**R/I**
Plus an Energy Charge per kWh:	$ 0.03824	$ 0.03711	**T/I**
Plus a Maximum Load Charge per kVA:			**T**
Peak Demand Period:	$ 6.30	$ 6.41	**T/I**
Intermediate Demand Period:	$ 4.48	$ 4.56	**T/I**
Base Demand Period:	$ 2.83	$ 1.35	**T/R**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate **FLS**
Fluctuating Load Service

ADJUSTMENT CLAUSES

The amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Standard Rate **FLS**
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA

Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours, if any, under the CURTAILABLE SERVICE RIDER CSR. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System ("LKE System") owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of LG&E and KU. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 35

Standard Rate **LS**
Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is offered under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of street, driveways, yards, lots, and other outdoor areas where secondary voltage of 120/240 is available.

Service will be provided under written contract, signed by customer prior to service commencing, when additional facilities are required.

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities.

OVERHEAD SERVICE
Based on Customer's lighting choice, Company will furnish, own, install, and maintain the lighting unit. A basic overhead service includes lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company will, upon request furnish ornamental poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for basic overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	
High Pressure Sodium					
452	Cobra Head	16,000	0.181	$13.78	
453	Cobra Head	28,500	0.294	16.17	
454	Cobra Head	50,000*	0.471	18.61	
455	Directional	16,000	0.181	$14.73	
456	Directional	50,000*	0.471	19.44	
457	Open Bottom	9,500	0.117	$11.93	
Metal Halide					D
473	Directional	32,000*	0.350	$19.89	T
					D
Light Emitting Diode (LED)					N
490	Cobra Head	8,179	0.080	$14.62	N
491	Cobra Head	14,166	0.134	17.73	N
492	Cobra Head	23,214*	0.228	27.18	N
493	Open Bottom	5,007	0.050	$ 9.65	N
					T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

OVERHEAD SERVICE (continued) T

Should Customer request underground service, Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of Company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the overhead lighting system.

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider. For wood poles installed prior to 3/1/2010, such charge will be in accordance with the rates listed on Sheet No. 36.1 of the Restricted Lighting Service Rate RLS Tariff. T

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Decorative Smooth	Monthly Charge Historic Fluted	
High Pressure Sodium						
412	Colonial, 4-Sided	5,800	0.083	$22.30		I
413	Colonial, 4-Sided	9,500	0.117	22.85		
444	Colonial, 4-Sided	16,000	0.181	24.06		
415	Acorn	5,800	0.083	$24.47		
416	Acorn	9,500	0.117	24.42		
445	Acorn	16,000	0.181	25.64		
427	London	5,800	0.083		$36.76	I
429	London	9,500	0.117		37.15	
431	Victorian	5,800	0.083		$36.40	I
433	Victorian	9,500	0.117		36.72	I
400	Dark Sky	4,000	0.060	$25.33		
401	Dark Sky	9,500	0.117	25.98		
					Westchester/Norfolk	
956	Victorian/London Bases				$ 4.63	I

T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
High Pressure Sodium (continued)						T
423	Cobra Head	16,000	0.181		$35.52	T/I
424	Cobra Head	28,500	0.294		38.42	T/I
425	Cobra Head	50,000*	0.471		45.85	T/I
439/420	Contemporary	16,000	0.181	$17.42	37.57	I
440/421	Contemporary	28,500*	0.294	19.37	40.07	I
441/422	Contemporary	50,000*	0.471	23.55	43.12	I
Metal Halide						D
481/482	Contemporary	32,000*	0.350	$21.67	$40.61	T/I
						D
Light Emitting Diode (LED)						N
496	Cobra Head	8,179	0.080		$53.90	
497	Cobra Head	14,166	0.134		57.01	
498	Cobra Head	23,214*	0.228		66.46	
499	Colonial, 4-Sided	5,665	0.068		$46.45	

Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the conventional overhead lighting system.

Where Customer's location would require the installation of additional facilities, Company may furnish, own, and maintain the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill. Billing for this service to be made a part of bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff. T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following: T

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer.

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement lighting within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **RLS**

Restricted Lighting Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rate schedule is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS. Spot replacements will not be available for Mercury Vapor and Incandescent rate codes. **T** **T**

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole. **T**

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities. **T** **T**

OVERHEAD SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only).

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Fixture & Wood Pole	Monthly Charge: Fixture & Orn. Pole	
Mercury Vapor							
252	Cobra/Open Bottom	8,000	0.210	$10.56			I
203	Cobra Head	13,000	0.298	12.04			I
204	Cobra Head	25,000	0.462	14.84			I
209	Cobra Head	60,000*	1.180	30.34			T/I
207	Directional	25,000	0.462	$16.93			I
210	Directional	60,000*	1.180	31.58			T/I
201	Open Bottom	4,000	0.100	$ 9.03			I
Metal Halide							
470/471	Directional	12,000	0.150	$13.81	$16.56		N/I
474/475	Directional	32,000*	0.350		22.18	$29.64	T
476/477	Directional	107,800*	1.080	42.04	45.23		N

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DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE

Rate Code		Monthly Charge	
Wood Pole			
958	Installed Before 3/1/2010	$11.32	
900	Installed Before 7/1/2004	2.68	I

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 200 feet of conductor per fixture on appropriate poles.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
High Pressure Sodium						
275	Cobra/Contemporary	16,000	0.181		$33.62	I
266	Cobra/Contemporary	28,500	0.294		36.97	I
267	Cobra Contemporary	50,000*	0.471		42.43	T/I
276	Coach/Acorn	5,800	0.083		$19.76	I
274	Coach/Acorn	9,500	0.117		22.85	I
277	Coach/Acorn	16,000	0.181		24.06	I
279/278	Contemporary	120,000*	1.000	$45.11	$76.24	T
417	Acorn, Bronze	9,500	0.117		$25.33	I
419	Acorn, Bronze	16,000	0.180		26.48	I
280	Victorian	5,800	0.083	$26.53		I
281	Victorian	9,500	0.117	27.85		I
282	London	5,800	0.083	$26.73		I
283	London	9,500	0.117	28.46		I

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
High Pressure Sodium (continued)						T
426	London	5,800	0.083		$36.37	I
428	London	9,500	0.117		35.83	I
430	Victorian	5,800	0.083		36.01	I
432	Victorian	9,500	0.117		36.32	I
Victorian/London Bases						
950	Old Town				$ 4.51	I
951	Chesapeake				4.24	I
Poles						
901	10’ Smooth Pole				10.82	T
902	10’ Fluted Pole				12.91	T
Mercury Vapor						
318	Cobra Head	8,000	0.210		$19.56	I
314	Cobra Head	13,000	0.298		21.54	I
315	Cobra Head	25,000	0.462		25.78	I
						D
206	Coach	4,000	0.100		$14.14	I
208	Coach	8,000	0.210		16.12	I
Metal Halide						N
479/480	Contemporary	12,000	0.150	$17.18	$32.31	N
483/484	Contemporary	107,800*	1.080	45.01	58.35	N
Incandescent						
349	Continental Jr.	1,500	0.102		$ 9.57	
348	Continental Jr.	6,000	0.447		13.93	

Where Customer’s location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

T

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

DUE DATE OF BILL

Payment is due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill. Billing for this service to be made a part of the bill rendered for other electric service. **T T T T**

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company’s judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

Standard Rate **LE**
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE
$0.06934 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

CONDITIONS OF DELIVERY
1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

2. The location of the point of delivery of the energy supplied hereunder and the voltage at which such delivery is effected shall be mutually agreed upon by Company and the customer in consideration of the type and size of customer's street lighting system and the voltage which Company has available for delivery.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Standard Rate **TE**

Traffic Energy Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, and emergency sirens. **T** **T**

RATE

Basic Service Charge per month:	$4.00 per delivery point	**T**
Plus an Energy Charge per kWh:	$0.08533	**T/I**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

CONDITIONS OF SERVICE

1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.

3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **PSA** **T**

Pole and Structure Attachment Charges

APPLICABLE

In all territory served.

AVAILABILITY

Available to the facilities of cable television system operators and telecommunications carriers as provided below except: (1) facilities of incumbent local exchange carriers with joint use agreements with the Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. Nothing in this tariff expands the right to attach to the Company's structures beyond the rights otherwise conveyed by law.

APPLICABILITY OF SCHEDULE TO CURRENT LICENSE AGREEMENTS

Any telecommunication carrier that executed a license agreement permitting attachments to the Company's structures prior to the effective date of this Schedule shall be subject to the rates, terms, and conditions of this Schedule upon expiration or termination of its license agreement.

DEFINITIONS

"Affiliate" means, with respect to an entity, any entity controlling, controlled by, or under common control with such entity.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means the Cable or Wireless Facilities and all associated appliances including without limitation any overlashed cable, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or otherwise conflicts with Company's electric design and construction standards.

"Attachment Customer" means a customer that attaches its facilities to one or more of the Company's Structures and has executed an Attachment Customer Agreement with the Company.

"Attachment Customer Agreement" means the written agreement provided by the Company and executed between Attachment Customer and Company incorporating the terms and conditions of this Schedule.

"Cable" means the fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Cable television system operator" means a Person who operates a system that transmits television signals, for distribution to subscribers of its services for a fee, by means of wires or cables connecting its distribution facilities with its subscriber's television receiver or other equipment connecting to the subscriber's television receiver, and not by transmission of television signals through the air, and subscription to the system's service is available to the public.

"Communication Space" means the area below the Communication Worker Safety Zone to the limit of allowable NESC clearance, department of transportation or other governmental requirements, and Company's internal construction standards on poles.

"Communication Worker Safety Zone" means the space between the facilities located in the Supply Space and facilities located in the Communications Space on poles.

"Contractor" means any Person employed or engaged by Attachment Customer to perform work or render services upon or in the immediate vicinity of Company's Structures or associated facilities other than Attachment Customer and Attachment Customer's employees.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69 kV, but does not include a non-wood street light pole or a wood street light pole that is not located in a public right-of-way.

"Duct" means a pipe, tube, conduit, manhole, or other structure made for supporting and protecting electric and/or communications wires or cables and in which wires, cables and conduits may be placed for support or protection but excluding (1) any pipe now or previously used for the transmission or distribution of natural gas, (2) any duct system supporting electric supply lines operated at 69kV or greater, and (3) any vault.

"High Volume Application" means an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes submitted to Company within a 30-day period.

"Macro Cell Facility" means a wireless communications system site that is typically high-power and high-site, and capable of covering a large physical area, as distinguished from a distributed antenna system (DAS), small cell, or WiFi attachment, by way of example. Macro Cell Facilities are typically, but not exclusively, co-located on Transmission Poles and communications monopoles and towers.

"Make Ready Survey" means a survey, in the form prescribed by the Company from time to time, prepared by the Company or an Approved Contractor describing in reasonable detail the make-ready engineering requirements, and such other information as the Company may require, for the installation of an Attachment or group of Attachments on a Structure or group of Structures.

"NEC" means the National Electrical Code.

"NESC" means the National Electrical Safety Code.

"Person" is defined by KRS 278.010(2).

"Service Drop" means a Cable, attached to a pole with a J-hook or other similar hardware that connects the trunk line to an Attachment Customer's premises.

"Structure" means any Company pole, conduit, duct, or other facility normally used by the Company to support or protect its electric conductors but shall not include (1) any Transmission Pole other than Transmission Poles to which the Company has attached its own electric supply lines operated at less than 69kV; (2) any street light pole that is not a wood pole located in a public right-of-way; or (3) any pole that the Company has leased to a third party.

"Supply Space" means the space above the Communications Worker Safety Zone used for the installation of electric supply lines.

"Telecommunications carrier" means a Person who operates a system that (1) transmits by wire or wireless means, between or among points specified by the user, information of the user's choosing without change in the form or content of the information as sent or received, and (2) provides such transmission services for a fee directly to or for the public, or to such classes of users as to be effectively available directly to or for the public, and includes, but is not limited to, internet service providers, voice over internet protocol service providers, cellular and mobile phone service providers or resellers of such services.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69 kV or greater.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Attachment Customer's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with the Company's electric design and construction standards.

ATTACHMENT CHARGES

$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$ 84.00 per year for each Wireless Facility.

BILLING

All attachment charges for use of Structures will be billed semi-annually based upon the type and number of Attachment Customer's Attachments reflected in Company's records on December 1 and June 1. A bill issued under this Schedule shall be due upon its issuance. Any bill not paid in full within 60 days of its issuance shall be assessed a late payment fee of 3 percent on the bill's current charges. If the Attachment Customer fails to pay all charges and fees billed within six months of the bill's issuance, the Company may remove any or all of Attachment Customer's

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Attachments. In lieu of or in addition to removal of Attachments, the Company may exercise any other remedies available under law to address Attachment Customer's failure to make timely payment of any charges assessed under this Schedule.

TERM OF SERVICE

An executed Attachment Customer Agreement shall be for a term of 10 years and shall thereafter automatically renew for successive one year periods unless Company or Attachment Customer provides the other with written notice of termination at least 60 days prior to the renewal date.

TERMS AND CONDITIONS OF ATTACHMENT

Attachments to Company's Structures that do not interfere with the Company's electric service requirements and the Attachments of existing customers and joint users shall be permitted in accordance with the terms and conditions of this Schedule. The Terms and Conditions set forth in Section 5 of this Tariff shall also be applicable to the extent they are not in conflict with or inconsistent with this Schedule's provisions.

1. **ATTACHMENT CUSTOMER AGREEMENT**
   No Attachments shall be made to Company's Structures until Attachment Customer has executed an Attachment Customer Agreement. The Attachment Customer Agreement shall incorporate the terms and conditions set forth in this Schedule.

2. **NO PROPERTY RIGHTS**
   No use, however extended, of Company Structures shall create or vest in the Attachment Customer any right, title or interest in the Structures. Attachment Customer Agreement confers only a non-exclusive right to affix and install Attachments to and on Company's Structures. The Company is not required to maintain any Structure for a period longer than demanded by its electric service requirements.

3. **USE OF COMPANY'S FACILITIES BY OTHERS**
   Nothing in this Schedule shall affect the rights or privileges previously conferred by the Company to others. The rights granted under this Schedule and the Attachment Customer Agreement shall at all times be subject to such previously conferred privileges and shall not affect the rights or privileges that may be conferred by the Company in the future to others.

4. **TRANSFER OF RIGHTS**
   Except as provided in this Schedule, Attachment Customer's rights under the Attachment Customer Agreement are non-delegable, non-transferable and non-assignable. Any delegation, transfer or assignment of any interest created by the Attachment Customer Agreement or this Schedule without Company's prior written consent is voidable at the Company's option.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

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Attachment Customer shall not permit a third party to overlash or utilize any Attachment without Company's prior written consent. Company may condition its consent upon such third party's compliance with all provisions of the Attachment Customer Agreement, this Schedule, and such other terms as Company may reasonably require.

5. COMPANY'S ABANDONMENT OF STRUCTURE

The Company shall provide an Attachment Customer with a minimum of 180 days' notice before abandoning a Structure to which the Attachment Customer has made an Attachment unless state or local law, easement provisions, or contractual obligations to a third party requires the Structure to be abandoned in a shorter period, in which case the Company shall provide as much notice as is reasonably practicable.

6. FRANCHISES AND EASEMENTS

Attachment Customer shall secure at its own expense any right-of-way, easement, license, franchise or permit from any Person that may be required for the construction or maintenance of Attachments by or for the Attachment Customer. If requested by Company, Attachment Customer shall submit to Company satisfactory evidence of such right-of-way, easement, license, franchise or permit. Company's approval of Attachments shall not constitute any representation or warranty regarding Attachment Customer's right to occupy or use any public or private right-of-way.

Upon an Attachment Customer's written request, the Company may provide to the Attachment Customer such non-private information as the Company may have regarding the name of the record landowners from which the Company obtained easements for Structures. Such information is provided without representation or warranty as to its accuracy or completeness. The Company has no obligation to correct or supplement any information so provided. If the Company provides assistance to the Attachment Customer in obtaining easements or other property rights, the Attachment Customer shall reimburse the Company's cost of providing such assistance within 30 days of its receipt of an invoice from Company.

Attachment Customer shall indemnify and save harmless Company from all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Attachment Customer to secure any right of way, easement, license, franchise or permit.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **PSA**

Pole and Structure Attachment Charges T

7. ATTACHMENT APPLICATIONS AND PERMITS

a. Unless waived by the Company, Attachment Customer shall make written application, in the form and manner prescribed by the Company for permission to install Attachments on or in any Structure. Each application shall include: (1) in the case of poles, the owner, number and location of all Structures for which license to attach is sought and the amount of space required thereon; (2) in the case of Ducts, the number of linear feet of Duct space and the specific location of each such Duct to be utilized, the amount of requested space, the nature of any changes or inner Duct or Ducts proposed to be installed and any other construction that might be required by the proposed Attachments; (3) the physical attributes of all proposed Attachments; (4) a load bearing study for each Attachment, unless the Company finds such study is not necessary; (5) the proposed start date for installation of the Attachments; (6) any issues then known to Attachment Customer regarding space, engineering, access or other matters that might require resolution before installation of Attachments; and (7) proposed make ready drawings. Company may request additional information be included with the application at its reasonable discretion. Attachment Customer shall clearly distinguish in its application between Distribution Poles and Transmission Poles for which Attachments are proposed. Any Approved Contractor gathering information for an application to use Ducts must be accompanied by a Company-designated inspector. The Company shall schedule Approved Contractor inspections of Ducts within 15 days of its receipt of a request for such inspection.

b. Attachment Customer shall be responsible for all costs associated with the application, a Make Ready Survey, engineering analysis, and the Company's review of the application. Attachment Customer shall reimburse Company upon presentation of an invoice for such costs. If the Attachment Customer does not request Attachments to a Transmission Pole or Duct, Company shall complete a Make Ready Survey within 60 days of its receipt of Attachment Customer's completed application. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for performance.

c. Upon completion of the Make Ready Survey, the Company shall notify Attachment Customer in writing whether its application for use of Company's Structures has been granted, of any necessary changes to the proposed construction drawings, and the conditions, if any, imposed on the installation or use of Attachments. The Company reserves the right to deny access to any Structure based upon lack of capacity, safety, reliability, engineering standards or other good reason. The Company may deny access to Transmission Poles in its discretion for any reason; provided that such denials shall be determined in a non-discriminatory manner. Transmission Poles that do not support electric supply lines operated at less than 69kV are not available for Attachments under this Schedule.

d. Within 15 days of notifying Attachment Customer of the approval of its application, Company shall provide Attachment Customer a written statement of the costs of any necessary Company make-ready work, including but not limited to rearrangement of electric supply facilities and pole change out. Attachment Customer shall indicate its approval of this statement by submitting payment of the statement amount within 15 days of receipt. If facilities of a third party are required to be rearranged or transferred, Attachment Customer shall coordinate with the third party for such rearrangement or transfer and shall pay the costs related thereto. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for preparation of a written statement of the costs of any necessary Company make-ready work.

e. If an existing Structure is replaced or a new Structure is erected solely to provide adequate capacity for Attachment Customer's proposed Attachments, Attachment Customer shall pay a sum equal to the actual material and labor cost of the new Structure, as well as any replaced appurtenances, plus the cost of removal of the existing Structure minus its salvage value, within 30 days of receipt of an invoice. The new Structure shall be Company's property regardless of any Attachment Customer payments toward its cost. Attachment Customer shall acquire no right, title or interest in or to such Structure.

f. If Company is unable to perform the Make Ready Survey and engineering analysis within the time period established under Section 7b, it shall advise the Attachment Customer and promptly meet with the Attachment Customer to develop a mutually agreeable plan of performance.

g. If Company fails to perform the make-ready work within 60 days of receipt of Attachment Customer's payment of the make-ready costs, Attachment Customer may perform such work at its expense using an Approved Contractor, except that Attachment Customer may not perform such work with respect to Transmission Poles or Ducts. Company shall refund any unexpended make-ready fees within 30 days of notice that Attachment Customer has performed the work. Attachment Customer shall notify Company upon completion of such make-ready work and Company may inspect such work prior to the construction of Attachments. Attachment Customer shall bear the cost of such Company inspection.

h. If Attachment Customer submits to Company within a 30-day period an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes, such application or applications shall be considered a High Volume Application. The provisions set forth in Sections 7b through 7g that relate to time period and cost-reimbursement of the Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make-ready work, shall not apply to High Volume Applications. The Company and Attachment Customer submitting a High Volume Application shall develop a mutually agreeable plan of performance and cost reimbursement for Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make ready work, shall set this plan to writing and shall file it with the Commission as a special contract.

i. A Service Drop may be affixed and installed on a Distribution Pole without making written application if (1) it is affixed within six (6) inches of Attachment Customer's existing Attachment, (2) it conforms to all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to construction and installation of Attachments, and (3) written notice of each such Service Drop is provided to Company in the month following the month of its installation. A Service Drop shall be counted as an Attachment for purposes of billing and permitting if it (1) is attached to a pole without an existing Attachment, (2) extends more than one span along the trunk line (in which case each individual pole to which such Service Drop is attached shall be treated as the site of an individual Attachment), or (3) is not affixed to a pole within six (6) inches of Attachment Customer's existing Attachment.

8. CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS

a. Attachment Customer shall not construct or install any Attachments until Company has approved in writing the design, construction, and installation practices for Attachment Customer's Attachments.

b. All Attachments shall be constructed and installed in a manner reasonably satisfactory to Company and so as not to interfere with the Company's present or future use of its Structures. Attachments in Ducts shall not include any splice enclosures or excess cable. Attachment Customer shall maintain, operate and construct all Attachments in such manner as to ensure Company's full and free access to all Company facilities. All Attachments shall conform to Company's electric design and construction standards and applicable requirements of the NESC, NEC, and all other applicable codes and laws. In the event of a conflict, the more stringent standard shall apply.

c. Attachment Customer shall identify each of its Attachments with a tag, approved in advance by Company, that includes Attachment Customer's name, 24-hour contact telephone number, and such other information as Company may require. Attachment Customer shall tag new Attachments at the time of construction. Any Attachments existing as of the date of execution of Attachment Customer Agreement shall be tagged within 180 days of the date of the Agreement. All Cable placed by Attachment Customer

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within a Company-owned or controlled Duct shall be enclosed within Attachment Customer furnished inner-duct and shall be clearly marked and identified as belonging to Attachment Customer at all access points.

d. In the design, installation and maintenance of its Attachments, Attachment Customer shall comply with all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to the work of constructing and installing the Attachments. All work shall be performed in accordance with the applicable standards of the NESC and the NEC, including amendments thereto adopted. Attachment Customer shall take all necessary precautions, by the installation of protective equipment or other means, to protect all Persons and property of all kinds against injury or damage caused by or occurring by reason of the construction, installation or existence of Attachments.

e. Attachment Customer shall immediately report to Company (1) any damage caused to property of Company or others when installing or maintaining Attachments, (2) any Attachment Customer's failure to meet the requirements set forth in this Schedule for assuring the safety of Persons and property and compliance with laws and regulations of public authorities and standard-setting bodies, and (3) any unsafe condition relating to Company's Structures identified by Attachment Customer.

f. Attachment Customer shall complete installation of its Attachments within 60 days of the later of approval of the application for such Attachments or, if make-ready work is required under such approval, completion of make-ready work, and shall notify Company in writing upon its completion. If Attachment Customer fails to complete the installation within this time period, the Company may revoke its permit for the Attachment. Prior to revoking the permit for the Attachment, Company shall provide written notice of the revocation to the Attachment Customer. Company may conduct an inspection of such Attachments. Attachment Customer shall reimburse Company within 30 days of presentation of an invoice for such inspections.

g. Company may monitor Attachment Customer's construction and installation of Attachments. If the need for a monitor is caused by Attachment Customer's failure to comply with the terms of this Schedule, the Attachment Customer Agreement, or any applicable law or regulation, Attachment Customer shall reimburse Company for the actual cost of any such monitoring within 30 days of receipt of an invoice for such cost. For locations where Attachment Customer's construction and installation are within Company underground facilities, Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within 30 days of receipt of an invoice.

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h. Attachment Customer may use qualified contractors of its own choice to perform work below the Communication Worker Safety Zone. For any work in or above the Communication Worker Safety Zone that Company allows Attachment Customer to perform, Attachment Customer shall use an Approved Contractor who may, at Company's discretion, be required to be accompanied by a Company-designated inspector. For any work in Company's Ducts, Attachment Customer shall use an Approved Contractor, who must be accompanied by a Company-designated inspector. The Company shall schedule a Company-designated inspector to accompany an Approved Contractor within 15 days of its receipt of such request for such inspector. The costs of such inspection shall be reimbursed to the Company in the same manner described in Section 8g above.

i. Attachment Customer shall comply with all applicable Federal, State, and local laws, rules and regulations with respect to environmental practices undertaken pursuant to the construction, installation, operation and maintenance of its Attachments. Attachment Customer shall not bring, store or utilize any hazardous materials on any Company site without the Company's prior express written consent. To the extent reasonably practicable, Attachment Customer shall restore any property altered pursuant to its performance under the Attachment Customer Agreement to its condition existing immediately prior to the alteration. Company has no obligation to correct or restore any property altered by Attachment Customer and bears no responsibility for Attachment Customer's compliance with applicable environmental regulations.

j. If Attachment Customer fails to install any Attachment in accordance with the standards and terms set forth in this Schedule and Company provides written notice to Attachment Customer of such failure, Attachment Customer, at its own expense, shall make necessary adjustments within 30 days of receipt of such notice. Subject to Section 15 of this Schedule, if Attachment Customer fails to make such adjustments within such time period, Company may make the repairs or adjustments, and Attachment Customer shall pay Company for the actual cost thereof, plus 50 percent, within 30 days of receipt of an invoice.

k. Attachment Customer is responsible for any damage, fines or penalties resulting from any noncompliance with the construction and maintenance requirements and specifications set forth in this Section 8. Company undertakes no duty to require any specific action by Attachment Customer and assumes no responsibility by requiring such compliance or by requiring Attachment Customer to meet any specifications or to make any corrections, modifications, additions or deletions to any work or planned work by Attachment Customer.

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l. Within 15 days of completion of the installation of the Attachment, Attachment Customer shall furnish Company with complete "as-built" drawings in a computer generated electronic format (or such other format as is agreeable to Company). Hand drawings shall not be submitted.

9. ADDITIONAL REQUIREMENTS FOR WIRELESS FACILITIES

a. Wireless Facilities Attachments may be attached to Distribution Poles only.

b. Company may require Attachment Customer to furnish with any written application for permission to install a Wireless Facilities Attachment a mock-up of the proposed Attachment.

c. Attachment Customer is solely responsible for ensuring that the radiofrequency ("RF") radiation emitted by its Wireless Facilities, alone and/or in combination with any and all sources of RF radiation in the vicinity, is within the limits permitted under all applicable governmental and industry standard safety codes for general population/uncontrolled exposure. Attachment Customer shall install appropriate signage on the poles to which Wireless Facilities have been attached, to warn line workers or the general public of the presence of RF radiation and the need for precautionary measures. Attachment Customer shall periodically inspect the signage and replace the signage if necessary to ensure that the signage, including text and warning symbols, remains clearly visible.

d. Each Wireless Facility installation shall include a switch that operates to disconnect and de-energize the antenna. In non-emergency circumstances, Company employees or contractors will make reasonable efforts to contact Attachment Customer at a telephone number that Attachment Customer has marked on the Wireless Facility installation to request a temporary power shut-down. Company personnel or those of other attaching entities will operate the power disconnect switch to ensure that the antenna is not energized while work on the pole is in progress. In emergency circumstances, Company personnel and those of other entities attached to Company poles may accomplish the power-down by operation of the power disconnect switch without advance notice to Attachment Customer.

e. Attachment Customer is solely responsible for ensuring compliance with all Federal Communication Commission antenna registration requirements, Federal Aviation Administration air hazard requirements, or similar requirements with respect to the location of Attachment Customer's Wireless Facilities on Company's poles.

f. All power supplies, equipment cabinets, meter bases and other equipment associated with the Wireless Facilities that are large enough to impede accessibility shall be installed off-pole, consistent with the applicable standards of the NESC, Company standards, and all applicable laws, rules, regulations, ordinances, and other applicable governmental directives.

10. OVERLASHING OF CABLE
Attachment Customer may overlash Cable to its existing Attachments without such overlashing being considered a separate Attachment subject to an Attachment Charge and without making written application provided: (1) a pole load analysis was performed for such overlashing; (2) such overlashing is completed within 120 days of the Attachment over which the overlashing occurs, (3) no make-ready work of any kind is necessary to accommodate the overlashing; (4) Attachment Customer obtained a permit from the Company for such overlashing; and (5) Attachment Customer provides Company with written notice of such overlashing within 30 days of completion. Any overlashing that fails to meet these conditions shall be deemed a new Attachment for all purposes except the assessment of Attachment Charges. Notwithstanding the foregoing, no bundle of Attachment Customer's Cable shall exceed two inches in diameter.

11. MAINTENANCE OF ATTACHMENTS AND STRUCTURES
Attachment Customer shall maintain Attachments in safe condition and in good repair, in a manner reasonably suitable to Company and so as not to conflict with any use of Company facilities (including Structures) by Company or any other Person using such facilities pursuant to any license or permit by Company. Attachment Customer shall not interfere with the working use of any other Person's property on or in such facilities or any such property, which may be placed on or near the Structures and other facilities.

Company reserves to itself, its successors, Affiliates and assigns, the right to maintain Structures and other Company property and to operate its business and maintain its property in such a manner as will, in its own judgment, best enable it to fulfill its own service requirements. Company shall not be liable to Attachment Customer for any interference with the operation of Attachment Customer's facilities, or loss of business arising in any manner out of the use of Company's Structures or other property.

12. NATIONAL JOINT UTILITIES NOTIFICATION SYSTEM
Within 30 days of executing Attachment Customer Agreement, and prior to making application for any Attachment, Attachment Customer will join National Joint Utilities Notification System ("NJUNS"), a web-based system developed to improve joint use communication, and will actively participate during the Term of Service, by entering field information into the NJUNS system within the times required by the system. Should Attachment Customer fail to actively participate in NJUNS and should such failure cause the Company to incur expense or liability to others, Attachment Customer shall reimburse the Company its expense and indemnify and hold the Company harmless from any damages or liability arising out of such failure. If Company at a later date elects to use a different web-based system for the joint use communication, it shall notify Attachment Customer at least sixty (60) days in advance of such change and Attachment Customer shall join that system.

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13. INSPECTIONS

Company may make periodic inspections for the purpose of determining compliance with this Schedule and with the Attachment Customer Agreement. Neither the Company's right to make inspections nor any inspection made by Company shall relieve an Attachment Customer of any responsibility, obligation or liability assumed under this Schedule.

Upon thirty (30) days' prior notice to Attachment Customer, Company may conduct a field inspection of its Structures to verify the number, location and type of Attachment Customer's Attachments. If the field inspection reveals more Attachments than shown in Company's existing records, the additional Attachments shall be treated as Unauthorized Attachments.

14. INTERFERENCE OR HAZARD

If Company notifies Attachment Customer in writing or orally with written confirmation that the Attachment Customer's Attachments or the condition of Attachment Customer's Attachments on or in any Structure (i) interfere with the use of such Structure or the operation of Company facilities or equipment, (ii) constitute a hazard to the service rendered by Company or any other Persons permitted by Company to use such Structures, (iii) cause a danger to employees of Company or other Persons, or (iv) fail to comply with the Company's standards and applicable requirements of the NESC, NEC, and all other applicable codes, laws and regulations, the Attachment Customer shall, within a reasonable period, remove, rearrange, repair or change its Attachments as needed or as directed by Company. In the case of any immediate hazard or danger, such period shall not exceed twenty-four (24) hours from Attachment Customer's receipt of such notice. In case of a hazardous condition or other emergency which requires the immediate remove or relocation of the Attachment Customer's Attachments, the Company may at Attachment Customer's expense, without prior notice and with no liability therefor, remove or relocate such Attachments; provided however, that Company shall notify Attachment Customer of such action as soon as reasonably possible by any appropriate means, including by telephone.

15. REARRANGEMENT; RELOCATION OF STRUCTURES; NEW STRUCTURES

a. If Attachment Customer's Attachments can be accommodated on or in existing Structures only by rearranging Company facilities, or if because of Attachment Customer's proposed Attachments, Company rearranges or transfers its facilities on or in any facility not owned by it, Attachment Customer shall reimburse Company for the actual expense incurred in making such rearrangement or transfer.

b. Upon 45 days prior written notice delivered to Attachment Customer, Company may replace, relocate, or remove any Structure and cause the alteration, relocation or removal of any Attachment, consistent with normal operating, maintenance and development procedures and prudent utility practices. In cases of emergency or dangerous situations, Company shall give only as much prior notice as practical under the circumstances. Company shall bear all costs and expenses of any relocation of the Structures not attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall bear all costs and expenses of any relocation and removal of the Attachments and all costs and expenses attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall be solely responsible for any losses occasioned by the interruption of Attachment Customer's business or operations and shall indemnify and hold Company harmless in connection with same.

c. If Company determines that any space occupied by the Attachments is required in connection with the services that the Company provides, Company may direct, by written notice to Attachment Customer, that such Attachments be removed from the Structures. Company shall use reasonable efforts to make space available as close in proximity as possible to the former Structures. Attachment Customer shall make such relocation within forty-five (45) days of the Company's request.

d. In the event a Person other than the Attachment Customer applies to make an Attachment to a Structure on which the Attachment Customer has placed an Attachment, and such application requires that Attachment Customer rearrange, transfer or relocate its Attachments, then Attachment Customer shall perform such rearrangement, transfer or relocation within 60 days of notice of such need to rearrange, transfer or relocate. Attachment Customer may condition its rearrangement, transfer or relocation upon reimbursement for the cost of such rearrangement, transfer or relocation. In the event Attachment Customer fails to perform such rearrangement, transfer or relocation within the time frame described above, the affected Attachments may be subject to rearrangement, transfer or relocation by the Person whose application necessitated the rearrangement, transfer or relocation to the extent permitted by law.

16. ABANDONMENT OF ATTACHMENT
Attachment Customer may at any time voluntarily remove its Attachments from any Structure, but shall immediately give Company written notice of such removal on the Company-prescribed form. Attachment Customer shall bear all cost of removal and any costs that Company incurs as a result of such removal and shall pay such costs within 30 days of receipt of an invoice. No refund of any amount paid for use of such Structure will result from Attachment Customer's voluntary removal nor shall such voluntary removal affect any other obligation or liability of Attachment Customer under this Schedule or the Attachment Customer Agreement.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

17. INDEMNITIES
Attachment Customer shall protect, defend, indemnify and save harmless Company, its Affiliates, their officers, directors, employees and representatives from and against all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature, including but not limited to costs and expenses of defending against the same, payment of any settlement or judgment therefor and reasonable attorney's fees that are incurred in such defense, by reason of any claims arising from Attachment Customer's activities under this Schedule, or from Attachment Customer's presence on the Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives, including but not limited to claims alleging (1) injuries or deaths to Persons; (2) damage to or destruction of property including loss of use thereof; (3) power or communications outage, interruption or degradation; (4) pollution, contamination of or other adverse effects on the environment; (5) violation of governmental laws, regulations or orders; or (6) rearrangement, transfer, or removal of any third party attachment on, from, or to any Company Structure. The indemnity set forth in this section shall include indemnity for any claims arising out of the joint negligence of the Attachment Customer and Company.

18. UNAUTHORIZED ATTACHMENTS
If Attachment Customer makes any Attachment that requires Company approval under this Schedule and Attachment Customer Agreement and has not obtained such approval, the Attachment Customer shall pay a penalty for the Unauthorized Attachment equal to double the current Attachment charge. Attachment Customer shall also submit to Company an application for approval of the Unauthorized Attachment within 30 days of the attachment's discovery. If the Attachment Customer fails to submit the required applications or fails to timely remit any necessary payments to Company in connection with the application process (including but not limited to any make-ready fees necessary to accommodate the Unauthorized Attachments), Company may remove any or all such Unauthorized Attachments at Attachment Customer's expense.

19. DEFAULT
If Attachment Customer fails to pay any undisputed fee required, perform any material obligations undertaken or satisfy any warranty or representation made under the Attachment Customer Agreement or with any of the provisions of this Schedule or default in any of its obligations under this Tariff and shall fail within 30 days after written notice from Company to correct such default or non-compliance, Company may, at its option, terminate the license covering the Structures to which such default or non-compliance is applicable; remove,

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relocate or rearrange at the Attachment Customer's expense the Attachments to which the default or non-compliance relates; or decline to permit additional Attachments until the failure or default is cured; by giving written notice to Attachment Customer of said termination. In the event of material or repeated default, Company may terminate the Attachment Customer Agreement and recover from the Attachment Customer all costs and expenses incurred as a result of reasonably related to the defaults. No refund of any attachment charge will be due on account of such termination.

20. TERMINATION

Either Company or Attachment Customer may terminate an Attachment Customer Agreement by providing the other written notice of termination at least 60 days prior to the end of the term of service.

Upon termination, Attachment Customer shall remove all Attachments from Structures and other Company property within 180 days. Attachment Customer shall bear all costs of such removal and shall exercise precautions to avoid damage to all Persons and to facilities of Company and other parties in so removing Attachments and assumes all responsibility for all damage it causes. If Attachment Customer's Attachments and other property are not removed within 180 days of termination of this Agreement, unless the time is extended by mutual agreement, Company may remove Attachment Customer's Attachments without liability and the Attachment Customer shall pay Company the cost of such removal within 30 days of receipt of an invoice.

Company may terminate an Attachment Customer Agreement without liability to Attachment Customer, upon giving 60 days advance written notice to the Attachment Customer that it has a reasonable belief that Company's performance under the Agreement would be illegal under applicable law or regulation or under any order or ruling issued by the PSC, or any other federal, state or local agency having regulatory jurisdiction over Company and same cannot be cured by Company without unreasonable expense or without materially and substantially altering the terms and conditions of the Attachment Customer Agreement; or that termination is required to preserve the Company's rights under any franchise, right-of-way, permit, easement or other similar right which is material and substantial to Company's business or operations. In the event of such termination, the Company and the Attachment Customer shall pay and perform obligations that have arisen prior to the effective date of termination, but shall not be obligated to pay and perform obligations, which arise after the effective date of termination.

21. WAIVER

Failure by the Company to enforce or insist upon compliance with any of the terms or conditions of this Agreement shall not constitute a general waiver or relinquishment of any such terms or conditions, but the same shall be and remain at all times in full force and effect.

22. INSURANCE

a. Throughout the term of service and so long as Attachment Customer's Attachments are on or in Company Structures, Attachment Customer shall provide and maintain the following insurance:

(1) Workers' Compensation and Employer's Liability Policy, which shall include: (a) Workers' Compensation (Coverage A), with statutory limits, and in accordance with the laws of Kentucky; (b) Employer's Liability (Coverage B) with minimum limits of $1,000,000 Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee; (c) 30 Day Cancellation Endorsement; and (d) Broad Form All States Endorsement.

(2) Commercial General Liability Policy, which shall have minimum limits of $1,000,000 each occurrence; $1,000,000 Products/Completed Operations Aggregate each occurrence; $1,000,000 Personal and Advertising Injury each occurrence, in all cases subject to $2,000,000 in the General Aggregate for all such claims, and including: (a) 30 Day Cancellation Endorsement; (b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by Company under the Attachment Customer Agreement; (c) Broad Form Property Damage; and (d) Insurance for liability arising out of blasting, collapse, and underground damage (deletion of X, C, U Exclusions).

(3) Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of $1,000,000 each occurrence.

(4) Umbrella/Excess Liability Insurance with minimum limits of $2,000,000 per occurrence; $2,000,000 aggregate, to apply to employer's liability, commercial general liability, and automobile liability.

(5) To the extent applicable, if any fixed wing or rotor craft aircraft will be used by Attachment Customer in performing the work, Aircraft Public Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury and property damage of $5,000,000 including passenger liability coverage.

(6) To the extent applicable, if engineering or other professional services will be separately provided by Attachment Customer as specified in the statements of work, then Professional Liability Insurance with limits of $3,000,000 per occurrence and $3,000,000 in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

b. Attachment Customer shall require its Contractors and subcontractors to provide and maintain the same insurance coverage as required of Attachment Customer.

c. Except with regard to workers' compensation and professional liability, each policy required under this schedule shall name Company as an additional insured and shall waive rights of subrogation against Company and Company's insurance carrier(s).

d. All policies shall be written by insurance companies that are licensed to do business in Kentucky and that are either satisfactory to Company or have a Best Rating of not less than "A-". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from Attachment Customer and the insurance carrier.

e. Company may request a summary of coverage of any of required policies or endorsements; but is not obligated to review any of Attachment Customer's certificates of insurance, insurance policies, or endorsements, or to advise Attachment Customer of any deficiencies in such documents. Company's receipt or review of such documents shall not relieve Attachment Customer from or be deemed a waiver of Attachment Customer's obligations to maintain insurance as provided.

f. Attachment Customer shall submit evidence of such coverage(s) to Company prior to the start of any work under the Attachment Customer Agreement and shall notify Company, prior to the commencement of any work pursuant to any statement of work and/or purchase order, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the Company's benefit

g. Attachment Customer shall provide notice of any accidents or claims involving Attachment Customer's Attachment or Attachment Customer's work under this Schedule and the Attachment Customer Agreement to the Company's designated representative.

23. PERFORMANCE ASSURANCE

Attachment Customer shall furnish a surety bond at the following times and in the following amounts and for the following purposes:

(a) During the period of the Attachment Customer's initial installation of its wireline pole attachments and at the time of any expansion involving more than 75 poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which the Attachment Customer intends to make a wireline pole attachment;

(b) Upon satisfactory completion of the Attachment Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);

(c) After Attachment Customer has been a customer of Company pursuant to the Attachment Agreement and is not in default under that agreement for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof)

(d) If an Attachment Customer proposes to attach a Wireless Facility or Facilities to a Structure, Attachment Customer shall post a surety bond in the amount of $1,500 for each pole to which a wireless attachment is attached. The amount of the bond shall not be reduced upon completion of installation or other event.

Each surety bond shall contain the provision that it shall not be terminated prior to six months after Company's receipt of written notice of the desire of the bonding or insurance company to terminate such bond. Company may waive this requirement if an acceptable replacement bond is received before the six months has ended. Upon receipt of such termination notice, Company shall request Attachment Customer to immediately remove its Cables, Wireless Facilities, Attachments and all other facilities from Company Structures. If Attachment Customer should fail to complete the removal of all of its facilities from Company's Structures within 30 days after receipt of such request, then Company may remove Attachment Customer's facilities at Attachment Customer's expense and without liability for any damage to Attachment Customer's facilities. Such bond shall guarantee the payment of any sums which may become due to attachment charges, inspections or work performed by Company under this Schedule or the Attachment Customer Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

Each surety bond shall be issued by an entity having a minimum corporate debt rating of A- by Standard & Poor's Financial Services LLC at the time of issuance and at all times the relevant bond is outstanding.

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24. NOTICES
Any notice, or request, required by this Schedule or the Attachment Customer Agreement shall be deemed properly given if sent overnight by nationally recognized overnight courier, sent by certified U.S. mail, return receipt requested, postage prepaid, or sent by telecopier with confirmed receipt, to Company's and Attachment Customer's designated representative. The designation of the representative to be notified, his address and/or telecopier number may be changed at any time by similar notice.

25. LIENS
To the extent permitted by law, in the event any construction lien or other encumbrance shall be placed on the Attachments as a result of the actions or omissions of Attachment Customer or its Contractor, Attachment Customer shall promptly, in accordance with applicable laws, discharge such lien or encumbrance without cost or expense to Company. Attachment Customer shall indemnify Company for any and all actual damages that may be suffered or incurred by Company in discharging or releasing said lien or encumbrance.

26. FORCE MAJEURE
In the event Attachment Customer or Company is delayed in or prevented from performing any of its respective obligations under an Attachment Customer Agreement or this Schedule due to acts of God, war, riots, civil insurrection, acts of the public enemy, strikes, lockouts, acts of civil or military authority, government shutdown, fires, floods, earthquakes, fiber, cable or other material failures, shortages or unavailability, delay in delivery not resulting from its failure to timely place orders therefor, lack or delay in transportation, or due to any other causes beyond its reasonable control, then such delay or nonperformance shall be excused.

27. LIMITATION OF LIABILITY
IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE TO ATTACHMENT CUSTOMER FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE, (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES AND (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 27 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to customers to be served or currently being served under Company's Standard Rate Schedules GS (with energy usage of 500 kWh or higher per month), PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles.

Charging station is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas.

A basic underground service includes the charging station, existing transformer (or secondary pedestal) and 208/240 volt single-phase service, and necessary conductor and equipment typical of an underground service drop. Said service drop can originate from underground or overhead equipment. Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own and install all duct systems and associated equipment.

Where the location of existing facilities is not suitable, and Customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$183.66	$307.43	**T** **I**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

ENERGY CONSUMPTION

Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 5,852 kilowatt-hours.

PAYMENT

The EVSE charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions in this Tariff Book, except as set out herein.

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the Customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.

4. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests installation of replacement facilities within five (5) years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of charging station is not permitted. Upon permanent discontinuance of service, charging station and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

8. Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE

The Monthly Charging Unit Fee shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

Standard Rate **EVC**
Electric Vehicle Charging

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts the Company's fee structure for the vehicle charging service. EVC is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards.

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

RATE
Fee Per Hour: $ 2.92 **I**

Charging Unit Fee includes an Energy Charge and Adjustment Clauses. **T**

Charging sessions of less than a full hour will be prorated. **T**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased in accordance with the following:

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

1. Service shall be furnished under the following Terms and Conditions and excludes the Company's Terms and Conditions set out in this Tariff Book.

2. EV Customer is required to pay by means of credit card or Charging Station Supplier account.
   a. Credit Card must be chip enabled (if card is not chip enabled, Customer must call the Charging Station Supplier at toll-free number provided at station), or
   b. EV Customer is required to open a Charging Station Supplier account and accepts all terms and conditions of Charging Station Supplier.

3. Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay, or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

4. Company is merely a supplier of electricity delivered to the point of connection of Company's and charging station facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of EV Customer or of third persons resulting from the presence, use or abuse of electricity or resulting from defects in or accidents to any of EV Customer's wiring, equipment, or vehicle, or resulting from any cause whatsoever other than the negligence of Company.

5. In no event shall Company have any liability to EV Customer, the owner of a vehicle receiving charging service, or any other party affected by the electrical service to EV Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to EV Customer, the owner of a vehicle receiving charging service, or any other party. In the event that EV Customer's use of Company's service causes damage to Company's property or injuries to persons, EV Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

6. By connecting a vehicle to the Charging Station, the EV Customer represents that the EV Customer is authorized to operate that vehicle and to connect it to the Charging Station for the purpose of receiving vehicle charging service.

7. All service and maintenance will be performed only during regular scheduled working hours of Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00355 dated April 11, 2016

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1), the customer will be charged $75.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Residential and general service customers may request and be granted temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected.

METER PULSE CHARGE

Where a customer desires and Company is willing to provide data meter pulses, a charge of $15.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

N

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;

3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;

4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter System (AMS) meter; or

5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be limited to customers served under applicable power schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to January 1, 2017. Company will not enter into contracts for additional curtailable demand, even with customers already participating in this rider, on or after January 1, 2017. T

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. Customer's choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. T

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

> Option A -- Customer may contract for a given amount of firm demand in kVA. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

Option B -- Customer may contract for a given amount of curtailable load in kVA by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand in kVA immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}.

Non-compliance for each requested physical curtailment shall be the measured positive value in kVA determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service:	$ 3.56 per kVA of Curtailable Billing Demand	**T/R**
Primary Voltage Service:	$ 3.67 per kVA of Curtailable Billing Demand	**T/R**

Non-Compliance Charge: $16.00 per kVA **T**

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M., (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred. T T T

CERTIFICATION

Upon commencement of service hereunder, the Customer shall be required to demonstrate or certify to the Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

Standard Rate Rider **SQF**

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:

In all territory served.

AVAILABILITY OF SERVICE

This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation.

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing month of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours)	$0.03581 per kWh
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours)	$0.02796 per kWh.
3. During all other hours (off-peak hours)	$0.03234 per kWh.

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company	$0.03231 per kWh

SELECTION OF RATE AND METERING

Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.

If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").

If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.

In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.

Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.

PAYMENT

Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, that, if Seller is a customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as customer.

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

Standard Rate Rider SQF
Small Capacity Cogeneration and Small Power Production Qualifying Facilities

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).

2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.

3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.

4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a customer of Company. When Seller is a customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation,

or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.
7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.
8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.
9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.
10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

Applicable to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

The hourly avoided energy cost (AEC) in $ per MWh, which is payable to a QF for delivery of energy, shall be equal to Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month. The total amount of the avoided energy cost payment to be made to a QF in an hour is equal to [AEC x E_{QF}], where E_{QF} is the amount of megawatt-hours delivered by a QF in that hour and which are determined by suitable metering.

Capacity Component Payments

The hourly avoided capacity cost (ACC) in $ per MWh, which is payable to a QF for delivery of capacity, shall be equal to the effective purchase price for power available to Company from the inter-utility market (which includes both energy and capacity charges) less Company's actual variable fuel expense (AEC). The total amount of the avoided capacity cost payment to be made to a QF in an hour is equal to [ACC x CAP_i], where CAP_i, the capacity delivered by the QF, is determined on the basis of the system demand (D_i) and Company's need for capacity in that hour to adequately serve the load.

Determination of CAP_i

For the following determination of CAP_i, $C_{LG\&E}$ represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{LG\&E}$; $CAP_i = 0$

2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

   $C_{LG\&E} < D_i \leq [C_{LG\&E} + C_{QF}]$; $CAP_i = C_M$

3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:

   $D_i > [C_{LG\&E} + C_{QF}]$; $CAP_i = C_{QF}$

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar days) of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit the Customer's account for such purchases.

TERM OF CONTRACT

For contracts which cover the purchase of energy only, the term shall be one (1) year, and shall be self-renewing from year-to-year thereafter, unless canceled by either party on one (1) year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be five (5) years.

TERMS AND CONDITIONS

1. Qualifying facilities shall be required to pay for any additional interconnection costs, to the extent that such costs are in excess of those that Company would have incurred if the qualifying facility's output had not been purchased.
2. A qualifying facility operating in parallel with Company must demonstrate that its equipment is designed, installed, and operated in a manner that insures safe and reliable interconnected operation. A qualifying facility should contact Company for assistance in this regard.
3. The purchasing, supplying and billing for service, and all conditions applying hereto, shall be specified in the contract executed by the parties, and are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Terms and Conditions currently in effect, as filed with the Commission.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 1995

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Standard Rate Rider **NMS**

Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

DEFINITIONS

"Billing period" shall be the time period between the dates on which Company issues the customer's bills.

"Billing Period Credit" shall be the electricity generated by the customer that flows into the electric system and which exceeds the electricity supplied to the customer from the electric system during any billing period. A billing period credit is a kWh-denominated electricity credit only, not a monetary credit.

METERING AND BILLING

Net metering service shall be measured using a single meter or, as determined by Company, additional meters and shall be measured in accordance with standard metering practices by metering equipment capable of registering power flow in both directions for each time period defined by the applicable rate schedule. This net metering equipment shall be provided without any cost to the Customer. This provision does not relieve Customer's responsibility to pay metering costs embedded in the Company's Commission-approved base rates. Additional meters, requested by Customer, will be provided at Customer's expense.

If electricity generated by Customer and fed back to Company's system exceeds the electricity supplied to Customer from the system during a billing period, Customer shall receive a billing-period credit for the net delivery on Customer's bill for the succeeding billing periods. If Customer takes service under time-of-use or time-of-day rate schedule, Company will apply billing-period credits Customer creates in a particular time-of-day or time-of-use block only to offset net energy consumption in the same time-of-day or time-of-use blocks in any billing period. Any such unused excess billing-period credits will be carried forward and drawn on by Customer as needed. Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

NET METERING SERVICE INTERCONNECTION GUIDELINES

General – Customer shall operate the generating facility in parallel with Company's system under the following conditions and any other conditions required by Company where unusual circumstances arise not covered herein:

1. Customer to own, operate, and maintain all generating facilities on their premises. Such facilities shall include, but not be limited to, necessary control equipment to synchronize frequency, voltage, etc., between Customer's and Company's system as well as adequate protective equipment between the two systems. Customer's voltage at the point of interconnection will be the same as Company's system voltage.
2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.
3. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
4. Customer agrees to inform Company of any changes it wishes to make to its generating or associated facilities that differ from those initially installed and described to Company in writing and obtain prior approval from Company.
5. Company will have the right to inspect and approve Customer's facilities described herein, and to conduct any tests necessary to determine that such facilities are installed and operating properly; however, Company will have no obligation to inspect, witness tests, or in any manner be responsible for Customer's facilities or operation thereof.
6. Customer assumes all responsibility for the electric service on Customer's premises at and from the point of delivery of electricity from Company and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence or willful misconduct of Company.

Level 1 – A Level 1 installation is defined as an inverter-based generator certified as meeting the requirements of Underwriters Laboratories Standard 1741 and meeting the following conditions:

1. The aggregated net metering generation on a radial distribution circuit will not exceed 15% of the line section’s most recent one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
2. The aggregated net metering generation on a shared singled-phase secondary will not exceed 20 kVA or the nameplate rating of the service transformer.
3. A single-phase net metering generator interconnected on the center tap neutral of a 240 volt service shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

4. A net metering generator interconnected to Company's three-phase, three-wire primary distribution lines, shall appear as a phase-to-phase connection to Company's primary distribution line.
5. A net metering generator interconnected to Company's three-phase, four-wire primary distribution lines, shall appear as an effectively grounded source to Company's primary distribution line.
6. A net metering generator will not be connected to an area or spot network.
7. There are no identified violations of the applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8. Company will not be required to construct any facilities on its own system to accommodate the net metering generator.

Customer desiring a Level 1 interconnection shall submit a "LEVEL 1 - Application for Interconnection and Net Metering." Company shall notify Customer within 20 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 20 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Level 2 – A Level 2 installation is defined as generator that is not inverter-based; that uses equipment not certified as meeting the requirements of Underwriters Laboratories Standard 1741; or that does not meet one or more of the conditions required of a Level 1 net metering generator. A Level 2 Application will be approved if the generating facility meets the Company's technical interconnection requirements. Those requirements are available on line at www.lge-ku.com and upon request.

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Customer submitting a "Level 2 - Application for Interconnection and Net Metering" will provide a non-refundable inspection and processing fee of $100, and in the event that the Company determines an impact study to be necessary, shall be responsible for any reasonable costs of up to $1,000 of documented costs for the initial impact study.

Additional studies requested by Customer shall be at Customer's expense.

CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.
2. Customer shall represent and warrant compliance of the net metering generator with:
   a) any applicable safety and power standards established by IEEE and accredited testing laboratories;
   b) NEC, as may be revised from time-to-time;
   c) Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Public Service Commission of Kentucky;
   d) the rules and regulations of the Public Service Commission of Kentucky, as may be revised by time-to-time by the Public Service Commission of Kentucky:
   e) all other local, state, and federal codes and laws, as may be in effect from time-to-time.
3. Any changes or additions to Company's system required to accommodate the net metering generator shall be Customer's financial responsibility and Company shall be reimbursed for such changes or additions prior to construction.
4. Customer shall operate the net metering generator in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. Customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system.
5. Customer shall be responsible for protecting, at Customer's sole cost and expense, the net metering generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the net metering generator resulting solely from the negligence or willful misconduct on the part of the Company.
6. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to Customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the net metering generator comply with the requirements of this rate schedule.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

CONDITIONS OF INTERCONNECTION (continued)

7. Where required by the Company, Customer shall furnish and install on Customer's side of the point of interconnection a safety disconnect switch which shall be capable of fully disconnecting Customer's net metering generator from Company's electric service under the full rated conditions of Customer’s net metering generator. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, Customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.
8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company’s electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company’s electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.

   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer’s entire facility.
9. Customer agrees that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in net metering generator capacity will require a new “Application for Interconnection and Net Metering” which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in net metering generator capacity is allowed without approval.
10. Customer shall protect, indemnify and hold harmless Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys’ fees, for or on account of any injury or death

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

CONDITIONS OF INTERCONNECTION (continued)

of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating Customer's net metering generator or any related equipment or any facilities owned by Company, except where such injury, death or damage was caused or contributed to by the fault or negligence of Company or its employees, agents, representatives or contractors. The liability of Company to Customer for injury to person and property shall be governed by the tariff(s) for the class of service under which Customer is taking service.

11. Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial or other policy) for generating facilities. Customer shall upon request provide Company with proof of such insurance at the time that application is made for net metering.
12. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.
13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.
14. Customer shall retain any and all Renewable Energy Credits (RECs) generated by Customer's generating facilities.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

LEVEL 1

Application for Interconnection and Net Metering

Use this application form only for a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Submit this Application to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________________________

Customer Phone No.: ______________ Customer E-mail Address: ______________________

Project Contact Person: ______________________________________

Phone No.: ______________ E-mail Address (Optional): ______________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ______________________

Is Battery Storage Used: ____No _____Yes If Yes, Battery Power Rating: ______________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, *(optional: Utility accessible disconnect switch)* and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

Louisville Gas and Electric Company

LEVEL 2

Application for Interconnection and Net Metering

Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or does not meet any of the additional conditions under Level 1.

Submit this Application, along with an application fee of $100, to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________________ Account Number: ________________

Customer Address: ______________________________

Project Contact Person: ______________________________

Phone No.: ________________ E-mail Address (Optional): ______________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Total Generating Capacity of Generating Facility: ______________________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point *of* interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by *a* nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ______________________________ Date: ________________

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for non-standard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to line extensions or to other facilities which are necessary to provide basic electric service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term.

DEFINITION OF EXCESS FACILITIES

Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters.

EXCESS FACILITIES CHARGE

Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With No Contribution-in-Aid-of-Construction	1.32%

(b) making a one-time Contribution–in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage with Contribution-in-Aid-of-Construction	0.54%

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

PAYMENT

The Excess Facilities Charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT

The initial term of contract to the customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

Standard Rate Rider **RC**
Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has, and is willing, to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.66 per kW/kVA per Month	I
Primary Distribution	$1.50 per kW/kVA per Month	I

Applicable to the greater of:

(1) the highest average load in kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) recorded at either the principal distribution feed metering point or at the redundant distribution feed metering point during any 15-minute interval in the monthly billing period,
(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months, or
(3) the contracted capacity reservation.

TERM OF CONTRACT

The minimum contract term shall be five (5) years, and shall be renewed for one (1) year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement. Company may require that a contract be executed for a longer initial term when deemed necessary by the difficulty and/or high cost associated with providing the redundant feed or other special conditions.

Standard Rate Rider **IL**
Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

RATE

1. A contribution in aid of construction or an excess facilities charge shall be required for all special or added facilities, if any, necessary to serve such loads, as provided under the Excess Facilities Rider.
2. Plus the charges provided for under the rate schedule applicable, including any Basic Service Charge if applicable, Energy Charge, Maximum Load Charge (if load charge rate is used), Fuel Clause and the Minimum Charge under such rate adjusted in accordance with (a) or (b) herein.

Standard Rate Rider **IL**

Rider for Intermittent Loads

RATE (continued)

(a) If rate schedule calls for a minimum based on the total kW of connected load, each kVA of such special equipment shall be counted as one kW connected load for minimum billing purposes.

(b) If rate schedule calls for a minimum based on the 15-minute integrated load, and such loads operate only intermittently so that the kW registered on a standard 15-minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each kVA of such special equipment shall be counted as one-third kW load for minimum billing purposes.

MINIMUM CHARGE

As determined by this Rider and the Rate Schedule to which it is attached.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of the Company where:

1. Customer's business does not require permanent installation of Company's facilities, excluding service provided for construction of permanent delivery points for residences and commercial buildings, and is of such nature to require only seasonal service or temporary service; or

2. the service is over 50 kW, provided for construction purposes, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or

3. where Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment.

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 2 or 3, above, the Company will determine the term of service, which shall not exceed one (1) year.

CONDITIONS

Company may permit such electric loads to be served on the rate schedule normally applicable, but without requiring a yearly contract and minimum, substituting therefore the following conditions and agreements:

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.

2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above plus a monthly charge for the salvageable equipment at the Percentage With No Contribution -in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60.

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is from dusk to dawn as shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

Standard Rate Rider **SGE**
Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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DATE EFFECTIVE: June 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00467 dated February 22, 2010

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Standard Rate Rider **EDR**
Economic Development Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE
A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS
Brownfield Development
a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to minimum monthly billing loads of 500 kVA (or kW as is appropriate) or greater where the customer takes service from existing Company facilities.

Economic Development
c) Service under EDR for Economic Development is available to:
    1) new customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate); and

TERMS AND CONDITIONS

Economic Development

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined as follows:
   i. Company and the existing customer will determine Customer's Existing Base Load by calculating a 12-month rolling average of measured demand. **T**
   ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
   iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
   1) a description of the new load to be served;
   2) the number of new employees, if any, Customer anticipates employing associated with the new load;
   3) the capital investment Customer anticipates making associated with the EDR load;
   4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

e) Should Company determine a refundable contribution for the capital investment in Customer-specific facilities required by Company to serve the EDR load would ordinarily be required as set out under Company's Line Extension Plan, I. Special Cases, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.

g) Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which Company initiates service to Customer.

General (continued)

h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.

i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.

j) In any billing month where Customer's metered load is less than the load required to be eligible for either Brownfield Development or Economic Development, no credit under EDR will be calculated or applied to Customer's billing.

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

Louisville Gas and Electric Company

Standard Rate Rider **SSP**

Solar Share Program Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This optional, voluntary service is available to Company's customers taking service under any Standard Rate Schedule except those served under Retail Transmission Service, Fluctuating Load Service, Lighting Service, Restricted Lighting Service, Lighting Energy Service, Traffic Energy Service, Pole and Structure Attachment Charges, Electric Vehicle Supply Equipment, and Electric Vehicle Charging Service rate schedules. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program. **T**

RATE:

Upfront Fee

Subscription Fee	$40.00 per quarter-kW subscribed

Monthly Charge

Solar Capacity Charge	$6.29 per quarter-kW subscribed

Monthly Credits and Adjustments

	Rate Schedule	Credit per kWh
Solar Energy Credit (per kWh of pro rata energy produced by the Solar Share Facilities; number of kWh eligible for credit limited to customer's net kWh consumption on each bill)	RS	$0.04020
	RTOD-Energy	$0.04020
	RTOD-Demand	$0.04020
	VFD	$0.04020
	GS	$0.04021
	PS Secondary	$0.04071
	PS Primary	$0.03925
	TODS	$0.04049
	TODP	$0.03824

Solar FAC Adjustment	Subscriber's billing under Adjustment Clause FAC will be adjusted corresponding to number of kWh to which Solar Energy Credit applies

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

PROGRAM DESCRIPTION

The Solar Share Program is an optional, voluntary program that allows customers to subscribe capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer ("Subscriber") may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility. Payment of the Subscription Fee for the amount of capacity a customer seeks to subscribe will be due at the time of subscription. The Subscription Fee is a non-refundable administrative and customer education fee.

After subscribing and paying the Subscription Fee, Subscriber will pay the monthly Solar Capacity Charge for each quarter-kW subscribed beginning with the first billing period in which the subscribed capacity has been in service for the entire billing period. For each such billing period, Subscriber will also receive (i) a bill credit in the amount of the monthly Solar Energy Credit (see Rate above) times the pro rata amount of energy production attributable to Subscriber's subscribed capacity (limited by Subscriber's net kWh consumption for the period being billed) and (ii) a bill adjustment to the Subscriber's Fuel Adjustment Clause (FAC) credits or charges corresponding to the number of kWh for which the Subscriber receives a Solar Energy Credit.

Customers subscribing less than 50 kW DC will not be required to enter into a contract concerning their subscriptions; however, a customer may not reduce or cancel a subscription earlier than 12 months from the date of the customer's most recent change to the customer's subscription level. Therefore, a customer subscribing less than 50 kW has a 12-month commitment from the date of the customer's initial subscription, and may have a longer commitment if the customer subsequently increases subscribed capacity (which a customer may do at any time upon paying a Subscription Fee for the additional capacity) or if the customer chooses to decrease but not cancel the subscription after the initial 12 months. As addressed in Term of Contract below, customers subscribing 50 kW DC or more must enter into a 5-year contract with Company.

TERMS AND CONDITIONS

1) Subscriptions will be available on a first-come first-served basis, except that 25% of the capacity of Solar Share Facility No. 1 will be available only to residential customers for the first 45 days of the initial subscription period for new facility. Otherwise, all capacity in the Solar Share Facilities will be available for subscription by all customers on a first-come, first-served basis.

2) Individual subscriptions will be available in nominal 250 W DC (quarter-kW) increments.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 4, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00274 dated November 4, 2016

TERMS AND CONDITIONS (continued)

3) Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC. No customer may subscribe more than 250 kW DC in any single Solar Share Facility.

4) All Subscription Fees are non-refundable.

5) Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.

6) Customers may not owe any arrearage prior to participating in the Solar Share Program.

7) Subscribers' pro-rata share of the electricity produced by the Solar Share Facilities will be determined on a billing cycle basis. The corresponding Solar Energy Credit (per kWh) and Solar FAC Adjustment will appear on the Subscriber's bill.

8) Subscriber may continue to participate in the Program without incurring new or additional Subscription Fees if Subscriber changes premises within the combined Kentucky certified electric service territories of Louisville Gas and Electric Company and Kentucky Utilities Company. For clarity, changing premises does not exempt Subscriber from additional Subscription Fees for any additional capacity Subscriber elects to subscribe before, during, or after changing premises.

9) Subscribers whose customer accounts are closed for any reason will not be able to remain in the Program. Any such former Subscriber who reestablishes service with Company and seeks again to subscribe will have to pay again the Subscription Fee associated with the amount of capacity desired.

10) Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a subscription any time after 12 months following the date of the most recent change to Subscriber's subscription; however, any re-subscription will require Subscriber to pay Subscription Fees for all capacity re-subscribed, as well as for any capacity subscribed beyond Subscriber's original subscription. Similarly, if Subscriber decreases and later increases subscribed capacity, Company will require Subscriber to pay Subscription Fees for the re-subscribed capacity as well as any net new capacity subscribed. Decreases in subscribed amounts will not result in refunds of Subscription Fees to Subscriber.

11) Unless constrained by contract (see Term of Contract below), Subscriber may also increase subscribed capacity at any time. Increases in subscribed capacity will require payment of additional Subscription Fees.

TERMS AND CONDITIONS (continued)

12) Each subscription under the Solar Share Program applies to a particular meter. Subscribers with multiple meters may obtain multiple subscriptions, one per meter. But Company will not aggregate usage across multiple meters for applying credits, charges, or adjustments under Rider SSP; credits, charges, and adjustments under Rider SSP apply only to the meter associated with the subscription. The only exception to this restriction is if Subscriber has more than one meter for a single service, which multiple meters Company installed for its own operating convenience and bills on an aggregated basis in accordance with Company's Terms and Conditions.

13) Subscriptions are not transferrable or assignable between customers or between a single customer's meters.

14) Subscriber's Solar Energy Credit and corresponding Solar FAC Adjustment will apply each billing cycle to the Subscriber's pro rata amount of AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) or Subscriber's net energy consumption (kWh) for the billing period, whichever is less.

15) For all customers taking service under both of Riders NMS and SSP, Company will apply all provisions of Rider NMS to their bills before applying charges and credits under Rider SSP, including applying the Solar Energy Credit and Solar FAC Adjustment to such customers' net energy consumption. Therefore, customers should note that in months in which a customer taking service under Riders SSP and NMS has net zero energy consumption or net energy production under the terms of Rider NMS—including carryover net-energy credits from previous months, if any—the customer will receive zero Solar Energy Credit and Solar FAC Adjustment under Rider SSP. These provisions apply regardless of whether a customer first took service under Rider NMS before taking service under Rider SSP or vice versa, or if a customer began taking service under both riders simultaneously.

16) All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired.

17) Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use.

18) Service will be furnished under Company's Terms and Conditions except as provided herein.

TERM OF CONTRACT

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or currently being served under Company's Standard Rate Schedules GS (with energy usage of 500 kWh or higher per month), PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles, whereby the Customer installs and owns facilities on its side of the point of delivery of the energy supplied hereunder necessary to serve Company-provided charging station.

Charging station under this rider is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas. Customer is responsible for providing the appropriate voltage levels and connections necessary to operate Company-provided charger.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$133.77	$207.65	**T** **I**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

PAYMENT
The EVSE-R charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions set out in this Tariff Book, except as set out herein.

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.

4. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults.

5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement facilities within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of charging station is not permitted. Upon permanent discontinuance of service, charging station and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

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DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

8. Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE
As determined by this Rider and the Rate Schedule to which it is attached.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

Adjustment Clause **FAC**
Fuel Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where “F” is the expense of fossil fuel and “S” is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below:

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility’s own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages, plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

(3) Forced Outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (2)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(4) Sales (S) shall be all kWh sold, excluding inter-system sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(6) Base (b) period shall be April 2012 and the base fuel factor is $0.02725 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Orders in Case No. 2012-00553 dated May 17, 2013, and May 29, 2013, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2013, which begins June 26, 2013.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time of Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS. Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees, and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for each such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

RATE (continued)

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Residential Time-of-Day Energy Service, Volunteer Fire Department, and General Service customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, RTOD-Energy, VFD, and GS rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules RTOD-Demand, PS, TODS, TODP, and RTS) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved

programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

The DSM incentive amount related to programs for Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT

The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the "Three-Month Commercial Paper Rate" for the immediately preceding twelve-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DCCR = DSM CAPITAL COST RECOVERY
The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

$$DCCR = [(RB)\ (ROR + (ROR – DR)\ (TR / (1 – TR))] + OE$$

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC
Modifications to components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:
1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.
2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA, DCCR, and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RS, RTOD-Energy, RTOD-Demand, and VFD Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employs switches in homes to help reduce the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve-month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Residential Incentives Program

The Residential Incentives Program encourages customers to purchase and install various ENERGY STAR® appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive as noted in the table below.

Category	Item	Incentive
Appliances	Heat Pump Water Heaters (HPWH)	$300 per qualifying item purchased
	Washing Machine	$75 per qualifying item purchased
	Refrigerator	$100 per qualifying item purchased
	Freezer	$50 per qualifying item purchased
	Dishwasher	$50 per qualifying item purchased
Window Film	Window Film	Up to 50% of materials cost only; max of $200 per customer account; product must meet applicable criteria.
HVAC	Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum
	Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus additional $100 per SEER improvement above minimum

Residential Refrigerator Removal Program

The Residential Refrigerator Removal Program is designed to provide removal and recycling of working, inefficient secondary refrigerators and freezers from LG&E customer households. Customers participating in this program will be provided a one-time incentive. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Customer Education and Public Information

This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

Residential Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the RS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, PS, TODS, TODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employs switches or interfaces to customer equipment in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.9.

Commercial Conservation / Commercial Incentives
The Commercial Conservation / Commercial Incentive Program is designed to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for energy-efficiency improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable kW removed. New construction rebates are available on savings over code plus bonus rebates for LEED certification.

- Maximum annual incentive per facility is $50,000
- Customers can receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year
- Applicable for combined Prescriptive, Custom, and New Construction Rebates

Customer Education and Public Information
This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign and an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

School Energy Management Program
The School Energy Management program will facilitate the hiring and retention of qualified, trained energy specialists by public school districts to support facilitation of energy efficiency measures for public and independent schools under KRS 160.325.

Commercial Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the GS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:

- $5/month bill credit for June, July, August, and September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, and September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.
- If new customer registers by December 31, 2016, then a $25 gift card per air-conditioning unit, heat pump, water heater (40 gallon minimum) and/or swimming pool pump switch installed.
    - Customers in a tenant-landlord relationship will receive the entire $25 new customer incentive.

Multi-family Option:

- Tenant - $2/month bill credit per customer for June, July, August, and September per air conditioning unit, heat pump, or water heater (40 gallon minimum).
- Entire Complex Enrollment – Property owner receives $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, and September.
- If new customer registers by December 31, 2016, then a $25 gift card per air-conditioning unit or heat pump installed, where:
    - Customers in a tenant/property owner relationship where the entire complex participates, the property owner will receive a $25 bonus incentive per air conditioning unit, heat pump, or water heater (40 gallon minimum).
    - Customers in a tenant-landlord relationship where only a portion of the complex participates, the tenant will receive a $25 gift card new customer incentive.

Residential Refrigerator Removal Program

The program provides $50 per working refrigerator or freezer.

Commercial Load Management / Demand Conservation

Switch Option

- $5 per month bill credit for June, July, August, and September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50 kW demand reduction per control event.

- $25 per kW for verified load reduction during June, July, August, and September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

Monthly Adjustment Factors

Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00167 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00026 per kWh
DSM Incentive (DSMI)	$ 0.00008 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00156 per kWh
DSM Balance Adjustment (DBA)	$ (0.00011) per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00346 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00094 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00034 per kWh
DSM Incentive (DSMI)	$ 0.00005 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00021 per kWh
DSM Balance Adjustment (DBA)	$ (0.00027) per kWh
Total DSMRC for Rate GS	$ 0.00127 per kWh

Power Service Rate PS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00040 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00013 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00044 per kWh
DSM Balance Adjustment (DBA)	$ (0.00018) per kWh
Total DSMRC for Rate PS	$ 0.00081 per kWh

Time-of-Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, and Retail Transmission Service Rate RTS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00022 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00007 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00005 per kWh
DSM Balance Adjustment (DBA)	$ (0.00025) per kWh
Total DSMRC for Rates TODS, and TODP	$ 0.00010 per kWh

* These charges do not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

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DATE EFFECTIVE: June 30, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00398 dated March 31, 2016

Louisville Gas and Electric Company

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows: **T**

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE.
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; FLS; EVSE; and EVC. **T**

RATE
The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS
1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f) EAS is the total proceeds from emission allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

DEFINITIONS (continued)

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Adjustment Clause **OSS**
Off-System Sales Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules that are subject to the Fuel Adjustment Clause.

RATE
The monthly OSS Adjustment Factor per kWh delivered under each of the schedules to which this mechanism is applicable shall be calculated in accordance with the following formula:

OSS Adjustment Factor = 0.75 x [(P(m) / S(m)]

Where “P” is the net eligible margins from off-system power sales and “S” is the kWh sales in the current period (m) as defined in 807 KAR 5:056. The OSS Adjustment Factor will be applied as set out below.

1) The monthly OSS Adjustment Factor will be combined with the monthly FAC factor and billed as one.

2) Current expense month (m) shall be the second month preceding the month in which the combined FAC and OSS factor is billed.

3) The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Adjustment Clause **FF**

Franchise Fee Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS

Base Year - the twelve-month period ending November 30.

Collection Year - the full calendar year following the Base Year.

Base Year Amount -

1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) License fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE

The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING

1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
2) The franchise charge will appear as a separate line item on the Customer's bill and show the unit of government requiring the franchise.
3) Payment of the collected franchise charges will be made to the governmental franchising body as agreed to in the franchise agreement.

TERM OF CONTRACT

As agreed to in the franchise agreement. In the event such franchise agreement should lapse but payment of franchise fees, other local taxes, or permitting fees paid by Company by ordinance, franchise, or other governmental directive should continue, collection shall continue under this tariff.

TERMS AND CONDITIONS

Service will be furnished in accordance with the provisions of the franchise agreement in so far as those provisions do not conflict with the Terms and Conditions applicable to Company approved by and under the direction of the Kentucky Public Service Commission.

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE

The utility gross receipts license tax authorized under state law.

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per month. **T**

BILLING
The HEA charge shall be shown as a separate item on customer bills.

PURPOSE
Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service, unless any rate or rider under which you take service explicitly states otherwise. **T**
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

Louisville Gas and Electric Company

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions in each rate schedule, and which shall constitute a part of all applications and contracts for service. T T T

COMPANY AS A FEDERAL CONTRACTOR

The United Nations Convention on Contracts for the International Sale of Goods is specifically disclaimed and excluded and will not apply to or govern agreements between customers and Company.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which electric service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

CUSTOMER GENERATION T

All existing and future installations of equipment for the purpose of electric generation that is intended to run in parallel with utility service, regardless of the length of parallel operation, shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

General

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied electric service.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written, in-person, electronic, or oral application or contract, properly executed, will be required before Company is obligated to render electric service. Company may require any party applying for service to provide some or all of the following information for the party desiring service: full legal name, address, full Social Security Number or other taxpayer identification number, date of birth (if applicable), relationship of the applying party to the party desiring service, and any other information Company deems necessary for legal, business, or debt-collection purposes. Company shall have the right to reject for valid reasons any such application or contract, including the applying party's refusal to provide requested information. T

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

TRANSFER OF APPLICATION

Applications for electric service are not transferable and new occupants of premises will be required to make application for service before commencing the use of electricity. Customers who have been receiving electric service shall notify Company when discontinuance of service is desired, and shall pay for all electric service furnished until such notice has been given and final meter readings made by Company.

CONTRACTED DEMANDS

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company's sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on Company's system for determining Contract Demand minimum.

If Company or Customer terminates Customer's service under a rate schedule that contains demand charges and Customer subsequently applies to Company to reestablish service to the same premise or facility, Company must determine monthly billing demand for the reestablished service as though Customer had continuously taken service from the time of service termination through the reestablishing of service to Customer. For the purpose of determining the monthly billing demand described in the preceding sentence, the demand to be used for the period during which Customer did not take service from Company shall be the actually recorded demand, if any, for the premise or facility during that period. The preceding two sentences will not apply if Company determines, in its sole discretion, that material changes to Customer's facilities, processes, or practices justify establishing a new Contract Demand for the reestablished service. T

TERMS AND CONDITIONS

Customer Responsibilities

OPTIONAL RATES T

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which customer desires to receive service.

Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that customers will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

CUSTOMER'S EQUIPMENT AND INSTALLATION

Customer shall furnish, install and maintain at Customer's expense all electrical apparatus and wiring to connect with Company's service drop or service line. All such apparatus and wiring shall be installed and maintained in conformity with applicable statutes, laws or ordinances and with the rules and regulations of the constituted authorities having jurisdiction. Customer shall not install wiring or connect and use any motor or other electricity-using device which in the opinion of Company is detrimental to its electric system or to the service of other customers of Company. Company assumes no responsibility whatsoever for the condition of Customer's electrical wiring, apparatus, or appliances, nor for the maintenance or removal of any portion thereof.

In the event Customer builds or extends its own transmission or distribution system over property Customer owns, controls, or has rights to, and said system extends or may extend into the service territory of another utility company, Customer will notify Company of their intention in advance of the commencement of construction.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

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TERMS AND CONDITIONS

Customer Responsibilities

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ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of electric service or for the purpose of turning on and shutting off the supply of electricity when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

POWER FACTOR

Company installs facilities to supply power to its customers at or near unity power factor.

Company expects any customer to use apparatus which shall result in a power factor near unity However, Company will permit the use of apparatus which shall result, during normal operation, in a power factor not lower than 90 percent either lagging or leading.

Where Customer’s power factor is less than 90 percent, Company reserves the right to require the customer to furnish, at Customer’s own expense, suitable corrective equipment to maintain a power factor of 90 percent or higher.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Except in cases where Customer has contracted with Company for reserve or auxiliary service, no other electric light or power service will be used by Customer on the same installation in conjunction with Company’s service, either by means of a throw-over switch or any other connection.

LIABILITY

Customer assumes all responsibility for the electric service upon Customer's premises at and from the point of delivery of electricity and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Customer Responsibilities

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD T

The service connections, transformers, meters, and appurtenances supplied by Company for the rendition of electric service to its customers have a definite capacity which may not be exceeded without damage. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, transformers, or other equipment of Company caused by such material increase in the Customer's connected load. Should Customer make a permanent change in the operation of electrical equipment that materially reduces the maximum load required by Customer, Company may reduce Customer's contract capacity.

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines, Customer shall obtain from the property owner or owners the necessary consent to the installation and maintenance in said premises and in or about such intervening property of
all such wiring or other customer-owned electrical equipment as may be necessary or convenient for the supply of electric service to customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

The construction of electric facilities to provide service to a number of customers in a manner consistent with good engineering practice and the least public inconvenience sometimes requires that certain wires, guys, poles, or other appurtenances on a customer's premises be used to supply service to neighboring customers. Accordingly, each customer taking Company's electric service shall grant to Company such rights on or across his or her premises as may be necessary to furnish service to neighboring premises, such rights to be exercised by Company in a reasonable manner and with due regard for the convenience of the customer.

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

CHANGES IN SERVICE

Where Customer is receiving service and desires relocation or change in facilities not supported by additional load, Customer is responsible for the cost of the relocation or change in facilities through a Non-Refundable Advance.

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. Company has the right to install any meter or meters it deems in its sole discretion to be necessary or prudent to serve any customer, including without limitation a digital, automated meter reading, automated metering infrastructure, or advanced metering systems meter or meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

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POINT OF DELIVERY OF ELECTRICITY

The point of delivery of electrical energy supplied by Company shall be at the point, as designated by Company, where Company's facilities are connected with the facilities of Customer, irrespective of the location of the meter

EXTENSION OF SERVICE

The main transmission lines of Company, or branches thereof, will be extended to such points as provide sufficient load to justify such extensions or in lieu of sufficient load, Company may require such definite and written guarantees from a customer, or group of customers, in addition to any minimum payments required by the Tariff as may be necessary. This requirement may also be made covering the repayment, within a reasonable time, of the cost of tapping such existing lines for light or power service or both.

COMPANY’S EQUIPMENT AND INSTALLATION

Company will furnish, install, and maintain at its expense the necessary overhead service drop or service line required to deliver electricity at the voltage contracted for, to Customer's electric facilities.

Company will furnish, install, and maintain at its expense the necessary meter or meters. (The term meter as used here and elsewhere in these rules and regulations shall be considered to include all associated instruments and devices, such as current and potential transformers installed for the purpose of measuring deliveries of electricity to the customer.) Suitable provision for Company's meter, including an adequate protective enclosure for the same if required, shall be made by Customer. Title to the meter shall remain with Company, with the right to install, operate, maintain, and remove same. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage, or tamper with the same. Customer shall execute such reasonable form of easement agreement as may be required by Company.

TERMS AND CONDITIONS

Company Responsibilities

Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective electricity requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay, or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of electricity delivered to the point of connection of Company's and Customer's facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of Customer or of third persons resulting from the presence, use or abuse of electricity on Customer's premises or resulting from defects in or accidents to any of customer's wiring, equipment, apparatus, or appliances, or resulting from any cause whatsoever other than the negligence of Company

LIABILITY

In no event shall Company have any liability to Customer or any other party affected by the electrical service to Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to Customer or any other party. In the event that Customer's use of Company's service causes damage to Company's property or injuries to persons, Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

FIRM SERVICE

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide service for that load, the customer-generator must contract for such T
service, otherwise Company has no obligation to supply the non-firm service. T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedule herein, will be 60 cycle, alternating current delivered from Company's various load centers and distribution lines at typical nominal voltages and phases, as available in a given location, as follows:

SECONDARY VOLTAGES

Residential Service -

Single phase 120/240 volts three-wire service or 120/208Y volts three-wire service where network system is available.

Non-Residential Service -

1) Single phase 120/240 volts three-wire service or 120/208Y three-wire service where network system is available.
2) Three phase 240 volts three-wire, 480 volts three-wire service, 120/208Y volts four-wire service, or 277/480Y volts four-wire service.

PRIMARY VOLTAGES

According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 volts, or 34,500 volts.

TRANSMISSION VOLTAGES

According to location, 69,000 volts, 138,000 volts, or 345,000 volts.

The voltage available to any individual customer shall depend upon the voltage of Company's lines serving the area in which such customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of the Company, two-wire service is restricted to those customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, a customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.
   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to Customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b) The available voltage shall be the voltage on that distribution or transmission line which the Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

Residential electric service is available for uses customarily associated with residential occupation, including lighting, cooking, heating, cooling, refrigeration, household appliances, and other domestic purposes.

1. **DEFINITION OF RESIDENTIAL RATE** - Residential rates are based on service to single family units served through a single meter. Such service may include incidental usage of electricity for home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is practiced by Customer in his residence. Service to both a single family unit and a detached structure may both be served through a single meter, regardless of the meter location, and qualify for the residential service provided the consumption in the non-residential portion of the detached structure is incidental.

2. **DEFINITION OF SINGLE FAMILY UNIT** - A single family unit is a structure or part of a structure used or intended to be used as a home, residence, or sleeping place by one or more persons maintaining a common household. Residential service is not available to transient multi-family structures including, but not limited to, hotels, motels, studio apartments, college dormitories, or any structure without a permanent foundation or attached to sanitation facilities. Fraternity or sorority organizations associated with educational institutions may be classified as residential and billed at the residential rate.

3. **DETACHED STRUCTURES** - If Customer has detached structures that are located at such distance from Customer's residence as to make it impracticable to supply service through customer's residential meter, the separate meter required to measure service to the detached structures will be considered a separate service and billed as a separate customer.

4. **POWER REQUIREMENT** - Single-phase power service used for domestic purposes will be permitted under Residential Rates RS, RTOD-Energy, and RTOD-Demand when measured **T**
through the residential meter subject to the conditions set forth below:

   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

(c) In the case of multi-motored devices arranged for sequential starting of the motors, the above rules are considered to apply to the locked-rotor currents of the individual motors; if arranged for simultaneous starting of the motors, the rules apply to the sum of the locked-rotor currents of all motors so started.

(d) Any motor or motors served through a separate meter will be billed as a separate customer.

Louisville Gas and Electric Company

TERMS AND CONDITIONS

BILLING

METER READINGS AND BILLS

As used in the entirety of this Tariff, “meter reading” and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a “meter reading.” T

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customer meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. Provided, however, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of rendition thereof. If full payment is not received by the due date of the bill, a late payment charge will be assessed on the current month’s charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

BILLING

assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

CUSTOMER RATE ASSIGNMENT

If Customer takes service under a rate schedule the eligibility for which contains a minimum or maximum demand parameter (or both), Company will review Customer's demand and usage data at least once annually to determine the rate schedule under which Customer will take service until the next review and rate determination. Company will also conduct such a review and determination upon Customer's request. Company shall not be obligated to change Customer's rate determination based upon detection of a substantial deviation of Customer's demand or usage if, after consultation with Customer, Company determines in its sole discretion that such deviation is not indicative of Customer's likely long-term demand. Similarly, Company may assign Customer to a rate schedule for which Customer would not be eligible based solely on Customer's historical demand or usage, but Company may do so only as part of a review and rate determination that involves consulting with Customer about Customer's likely future demand, as well as Customer's special contract demand, if applicable.

Any such review and rate determination shall be deemed conclusively to be the correct rate determination for Customer for all purposes and for all periods until Company conducts the next such review and determination for Customer. Therefore, Company shall not be liable for any refunds to Customer based upon Customer's rate assignment, and Company shall not seek to back-bill Customer based upon Customer's rate assignment, for any periods between and including such reviews and determinations unless, and only in the event that, a particular review and rate determination are shown to have been materially erroneous at the time they were conducted, in which case Company may be liable for a refund, or may back-bill Customer, only for the period from the erroneous review and determination to the present or the next non-erroneous review and determination, whichever is shorter.

TERMS AND CONDITIONS

BILLING

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is then taking service under such a rate schedule, Company will not change Customer's rate assignment; it will remain Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is not then taking service under such a rate schedule, Company will (1) provide reasonable notice to Customer of the options available and (2) assign Customer to the rate schedule Company reasonably believes will be most financially beneficial to Customer based on Customer's historical demand and usage, which assignment Company will change upon Customer's request to take service under another rate schedule for which Customer is eligible. Company shall have no refund obligation or bear any other liability or responsibility for its initial assignment of Customer to a rate for which Customer is eligible; it is at all times Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

Nothing in this section is intended to curtail or diminish Customer's responsibility to choose among optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1. Likewise, except as explicitly stated in the paragraph above, nothing in this section creates an obligation or responsibility for Company to assign Customer to a particular rate schedule for which Customer is eligible if Customer is eligible for more than one rate schedule.

CUSTOMER RATE MIGRATION

A change from one rate to another will be effective with the first full billing period following a customer's request for such change, or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

CLASSIFICATION OF CUSTOMERS

For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes which create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32 and 33. All other non-residential customers will be defined as "commercial."

TERMS AND CONDITIONS

BILLING

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual customer consumption, Company will monitor the usage of each customer at least once quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1). Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

RESALE OF ELECTRIC ENERGY

Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

MINIMUM CHARGE

Without limiting the foregoing, the Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer's ability or interest in operating Customer's facility, including but without limitation any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company's ability to serve customer.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

DEPOSITS

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 8 except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service
3) Company may offer residential or general service customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first six (6) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service Rate RS - Sheet No. 5, Residential Time-of-Day Energy Service Rate RTOD-Energy – Sheet No. 6, and Residential Time-of-Day Demand Service Rate RTOD-Demand – Sheet No. 7.
2) The deposit for a residential customer is in the amount of $160.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2). For combination gas and electric customers, the total deposit will be $260.00.
3) Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

DEPOSITS

RESIDENTIAL (Continued)

5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

GENERAL SERVICE

1) General service customers are those customers served under General Service Rate GS, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $240.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2).The deposit for a General Service customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service energy usage is no more than 300 kWh per month.
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d)(1).
2) For customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer served under Residential Service Rate RS or any general service customer served under General Service Rate GS. If a residential customer, who is currently served under Residential Service Rate RS and is currently enrolled in the Budget Payment Plan, elects to take service under Residential Time-of-Day Energy Service Rate RTOD-Energy or Residential Time-of-Day Demand Service Rate RTOD-Demand, such customer would be removed from the Budget Payment Plan and restored to regular billing.

Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company, and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove Customer from the plan, restore the Customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts Customer from the provisions of these terms and conditions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Bill Format

LG&E
a PPL company

Mailed **4/21/16** for Account # **3000-3333-3333**

AMOUNT DUE	DUE DATE
$113.68	**5/26/16**

BILLING SUMMARY

Previous Balance	194.39
Payment(s) Received	-194.39
Balance as of 4/28/16	**$0.00**
Current Electric Charges	113.68
Total Current Charges as of 4/28/16	**$113.68**
Total Amount Due	**$113.68**

Account Name:	JOHN SMITH
Service Address:	100 Towne Creek Rd LOUISVILLE KY
Online Payments:	lge-ku.com
Telephone Payments:	(502) 589-1444, press 1-2-3 24 hours a day, $2.25 fee
Customer Service:	(502) 589-1444 M-F, 7am-7pm ET
Walk-in Center:	820 W. Broadway Louisville, KY 40202 M-F, 8am-5pm ET

Next read will occur 5/27/16 - 5/29/16 (Meter Read Portion 19)

CURRENT USAGE

ELECTRIC

Meter Reading Information	**Meter #500000**
Actual (R) kWh Reading on 4/28/16	26762
Previous (R) kWh Reading on 3/30/16	25669
Current kWh Usage	1093
Meter Multiplier	1
Metered kWh Usage	**1093**

CURRENT CHARGES

ELECTRIC **Rate:** Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 1,093 kWh)	88.27
Electric DSM ($0.00520 x 1,093 kWh)	5.68
Electric Fuel Adjustment ($0.00224 x 1,093 kWh)	2.45
Environmental Surcharge (5.860% x $107.15)	6.28
Home Energy Assistance Fund Charge	0.25
Total Charges	**$113.68**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due **5/26/16**	**$113.68**
After Due Date, Pay this Amount:	$117.09
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-3333-3333**
Service Address: 100 Towne Creek Rd

#926190003 3#

JOHN SMITH
100 TOWNE CREEK RD
LOUISVILLE, KY 40243 -1000

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

010300033333333000000001170900000113680000000000024

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

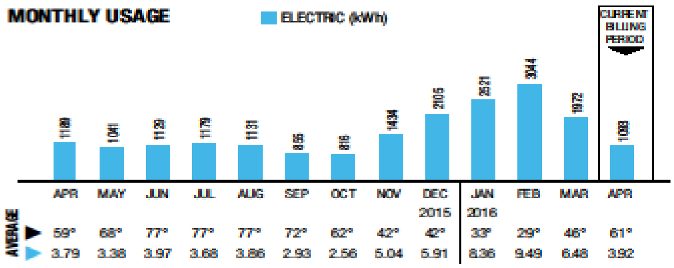
Page 2

Account # **3000-3333-3333**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**61°**	**60°**
Number of Days Billed	29	31
Avg. Electric Charges per Day	**$3.92**	**$3.79**
Avg. Electric Usage per Day (kWh)	37.69	38.35

MONTHLY USAGE



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.41

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY
MRU1 9833024, G000000
P194.39
PF:Y eB:P

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

Mailed 4/8/16 for Account # 3000-5555-5555

AMOUNT DUE $107.65

DUE DATE 5/1/16

LG&E a PPL company

Account Name:	JOHN SMITH
Service Address:	100 Cassidy Ln LOUISVILLE KY
Online Payments:	lge-ku.com
Telephone Payments:	502-589-1444, press 1-2-3 24 hours a day; $2.25 fee
Customer Service:	502-589-1444 M-F, 7am-7pm ET
Walk-in Center:	820 W. Broadway Louisville, KY 40202 M-F, 8am-5pm ET

Next read will occur 5/4/16 - 5/6/16 (Meter Read Portion 03)

BILLING SUMMARY

Previous Balance	185.14
Payment(s) Received	-185.14
Balance as of 4/7/16	**$0.00**
Current Electric Charges	54.03
Current Gas Charges	53.62
Total Current Charges as of 4/7/16	**$107.65**
Total Amount Due	**$107.65**

CURRENT USAGE

ELECTRIC

Meter Reading Information	**Meter # 700000**
Actual (R) kWh Reading on 4/7/16	58526
Previous (R) kWh Reading on 3/9/16	58072
Current kWh Usage	454
Meter Multiplier	1
Metered kWh Usage	**454**

GAS

Meter Reading Information	**Meter # 600000**
Actual (R) ccf Reading on 4/7/16	2704
Previous (R) ccf Reading on 3/9/16	2658
Current ccf Usage	46
Meter Multiplier	1
Metered ccf Usage	**46**

CURRENT CHARGES

ELECTRIC **Rate:** Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 454 kWh)	36.67
Electric DSM ($0.00520 x 454 kWh)	2.36
Electric Fuel Adjustment ($0.00224 x 454 kWh)	1.02
Environmental Surcharge (5.860% x $50.80)	2.98
Home Energy Assistance Fund Charge	0.25
Total Charges	**$54.03**

GAS **Rate:** Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 46 ccf)	12.15
Gas Supply Component ($0.49951 x 46 ccf)	22.98
Weather Normalization Adjustment ($0.26419 x 6.093 ccf)	1.61
Gas DSM ($0.01311 x 46 ccf)	0.60
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$53.62**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By 5/1/16	$107.65
After Due Date, Pay This Amount:	$110.91
Winterhelp Donation:	
Total Amount Enclosed:	

Account # 3000-5555-5555
Service Address: 100 Cassidy Ln

LG&E a PPL company

PO Box 9001960
Louisville, KY 40290-1960

#926190005 1#

JOHN SMITH
100 CASSIDY LN
LOUISVILLE, KY 40229-1000

01030005555555000000001118500000010859000000000000023

TERMS AND CONDITIONS

Bill Format

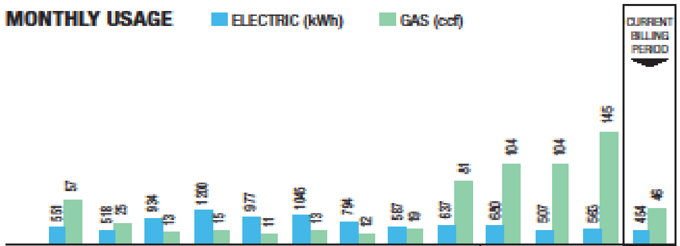
Page 2

Account # **3000-5555-5555**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**53°**	**49°**
Number of Days Billed	29	29
Avg. Electric Charges per Day	**$1.86**	**$2.08**
Avg. Gas Charges per Day	**$1.85**	**$2.10**
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97

MONTHLY USAGE



AVERAGE	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC 2015	JAN 2016	FEB	MAR	APR
▶	49°	60°	71°	77°	76°	79°	70°	58°	42°	40°	35°	29°	53°
▶	2.08	1.86	3.24	3.63	3.39	3.62	2.84	2.02	2.22	2.17	2.17	1.88	1.86
▶	2.10	1.17	0.87	0.85	0.85	0.92	0.89	0.99	2.54	3.11	3.82	3.50	1.85

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.26

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and RatesLouisville, Kentucky
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

B. When a dangerous condition is found to exist on the customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify the customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred final bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a **T**

TERMS AND CONDITIONS

Discontinuance of Service

lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications. **T**

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where the Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service.

T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Discontinuance of Service

Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered, and assessment of the charges under the Unauthorized Reconnect Charge provision of Special Charges incurred by reason of the fraudulent use. **T** **T** **T**

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY

In all territory served by where Company does not have existing facilities to meet Customer's electric service needs.

B. DEFINITIONS

1) "Company" shall mean Louisville Gas and Electric Company.
2) "Customer" shall mean the applicant for service. When more than one electric service is requested by an applicant on the same extension, such request shall be considered one customer under this plan when the additional service request(s) is only for incidental or minor convenience loads or when the applicant for service is the developer of a subdivision.
3) "Line Extension" shall mean the single phase facilities required to serve Customer by the shortest route most convenient to Company from the nearest existing adequate Company facilities to Customer's delivery point, approved by Company, and excluding transformers, service drop, and meters, if required and normally provided to like customers.
4) "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one year and where the intended use is not seasonal, intermittent, or speculative in nature.
5) "Commission" shall mean the Public Service Commission of Kentucky.

C. GENERAL

1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

5) Customer must agree in writing to take service when the extension is completed and have Customer's building or other permanent facility wired and ready for connection.
6) Nothing herein shall be construed as preventing Company from making electric line extensions under more favorable terms than herein prescribed provided the potential revenue is of such amount and permanency as to warrant such terms and render economically feasible the capital expenditure involved and provided such extensions are made to other customers under similar conditions.
7) Company may require a non-refundable deposit in cases where Customer does not have a real need or in cases where the estimated revenue does not justify the investment.
8) The Company shall not be obligated to extend its lines in cases where such extensions, in the good judgment of Company, would be infeasible, impractical, or contrary to good engineering or operating practice, unless otherwise ordered by Commission.

D. NORMAL LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25kVA and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ 1 above.

E. OTHER LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten (10) year refund period ends.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Line Extension Plan

E. OTHER LINE EXTENSIONS (continued)

5) Where Customer requires poly-phase service or transformer capacity above 25kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

F. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS

1) In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and through a subdivision may be required by Company to deposit the total cost of the extension.
2) Each year for ten (10) years Company shall refund to Customer, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

G. MOBILE HOME LINE EXTENSIONS

1) Company will make line extensions for service to mobile homes in accordance with 807 KAR 5:041, Section 12, and Commission's Orders.
2) Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home.
3) Company shall provide to Customer requesting permanent service for a mobile home a line extension in excess of 300 feet and up to 1,000 feet but Company may require the total cost of the footage in excess of 300 feet, based on the average cost per foot of the total extension, be deposited with Company by Customer. Beyond 1,000 feet the policies set forth in OTHER LINE EXTENSIONS shall apply.
4) Each year for four (4) years Company shall refund to Customer equal amounts of the deposit for the extension from 300 feet to 1,000 feet.
5) If service is disconnected for sixty (60) days, if the original mobile home is removed and not replaced by another mobile home or a permanent structure in sixty (60) days, the remainder of the deposit is forfeited.
6) No refund will be made except to the original customer.

H. UNDERGROUND LINE EXTENSIONS

General

1) Company will make underground line extensions for service to new residential customers and subdivisions in accordance with 807 KAR 5:041, Section 21.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

General (continued

2) In order that Company may make timely provision for materials, and supplies, Company may require Customer to execute a contract for an underground extension under these Terms and Conditions with Company at least six (6) months prior to the anticipated date service is needed and Company may require Customer to deposit with Company at least 10% of any amounts due under the contract at the time of execution. Customer shall deposit the balance of any amounts due under the contract with Company prior to ordering materials or commencement of actual construction by Company of facilities covered by the contract.
3) Customer shall give Company at least 120 days written notice prior to the anticipated date service is needed and Company will undertake to complete installation of its facilities at least thirty (30) days prior to that date. However, nothing herein shall be interpreted to require Company to extend service to portions of subdivisions not under active development.
4) At Company's discretion, Customer may perform a work contribution, to Company's specifications, including but not limited to conduit, setting pads, or any required trenching and backfilling, and Company shall credit amounts due from Customer for underground service by Company's estimated cost for such work contribution.
5) Customer will provide, own, operate and maintain all electric facilities on Customer's side of the point of delivery including the service and with the exception of Company's meter.
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company.
7) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
8) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.
9) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

1) Within the City of Louisville underground district or in those cases where Company's engineering or operating convenience requires the construction of an underground extension to an individual premise, the excess of the cost of an underground extension over that of an overhead extension will be at no cost.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

Individual Premises (continued)

2) In cases other than those specified in 1) above, where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

Medium Density Subdivisions

1) A medium density residential subdivision is defined as containing ten or more lots for the construction of new residential buildings each designed for less than five (5)-family occupancy.
2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount determined by a unit charge of $6.77 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be the Company's full estimate cost of construction. Where Customer is required to deposit with the Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $22.50 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
4) Each year for ten (10) years Company shall refund to Customer an amount determined as follows:
   a. Where customer is required to provide trenching and backfilling, a refund of $5,000 for each customer connected during that year.
   b. Where customer is required to provide a non-refundable advance, 500 times the difference in the unit charge advance amount in 3) and the non-refundable unit charge advance in 2) for each customer connected during that year.
5) In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

High Density Subdivisions

1) A high density residential subdivision is defined as building complexes consisting of two or more buildings each not more than three stories above grade and each designed for five (5) or more family occupancy.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

High Density Subdivisions (continued)

2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Other Underground Subdivisions

In cases where a particular residential subdivision does not meet the conditions provided for above, Customer requests and Company agrees to supply underground service, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

I. SPECIAL CASES

1) Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlines in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify the Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment.
2) Each year for ten (10) years, Company shall refund to Customer, an amount calculated by:
   a. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric demand billing of the monthly electric billing for that year of any customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company
   b. times the refundable amount divided by the estimated total ten-year base rate electric demand billing required to justify the investment.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

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DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Louisville Gas and Electric Company ("Company") system in the event of a capacity shortage and to restore service following an outage. Notwithstanding any provisions of these Energy Curtailment and Service Restoration Procedures, Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law.

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

For the purpose of these procedures, the following Priority Levels have been established:

I. Essential Health and Safety Uses -- to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use

A. "Hospitals", which shall be limited to institutions providing medical care to patients.

B. "Life Support Equipment", which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

C. "Police Stations and Government Detention Institutions", which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

G. "Transportation and Defense-related Services", which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential street, highway and signal-lighting services.

Although, when practical, these types of uses will be given special consideration when implementing the manual load-shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be Customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses -- Except as described in Section III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III Residential Use -- The priority of residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses -- The following and similar types of uses of electric energy shall be considered nonessential for all customers:

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DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

A. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

B. General interior lighting levels greater than minimum functional levels.

C. Show-window and display lighting.

D. Parking-lot lighting above minimum functional levels.

E. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

F. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

G. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

CURTAILMENT PROCEDURES

In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on curtailable contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Curtailable Service Rider tariff.

2. Power output will be maximized at Company's generating units.

3. Company use of energy at its generating stations will be reduced to a minimum.

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

CURTAILMENT PROCEDURES (continued)

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.

5. The Kentucky Public Service Commission will be advised of the situation.

6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.

7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.

8. Implement procedures for interruption of selected distribution circuits.

SERVICE RESTORATION PROCEDURES

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under PRIORITY LEVELS. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times to aid customers in assessing the need for alternative power sources and temporary relocations.

Special Contracts
Electric

Summary of Proposed Charges Under Electric Special Contracts

Customer 1	Propose to move to Rate TODP	
	Basic Service Charge:	$330.00 per month
	Plus an Energy Charge:	$0.03824 per kWh
	Plus a Maximum Load Charge per kVA:	
	Peak Demand Period:	$6.86
	Intermediate Demand Period:	$5.03
	Base Demand Period:	$3.18
Customer 2	Demand Charge:	$13.62 per kW of billing demand per month
	Energy Charge:	$0.03872

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

In the seventeen counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

Standard Rate **RGS**
Residential Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term "residential" customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, personal vehicle fueling, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. Company shall not be obligated to install an additional service to a residential customer for the purpose of the customer installing equipment for either electric standby generation or personal vehicle fueling.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation or personal vehicle fueling shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Company's Terms and **T**
Conditions. Additionally, service for gas for use in standby electric generation and personal vehicle **T**
fueling shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers.

RATE

Basic Service Charge per month:	$24.00 per delivery point	**T/I**
Plus a Distribution Charge per 100 cubic feet:	$ 0.25385	**T/R D**

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **RGS**
Residential Gas Service

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	
Home Energy Assistance Program	Sheet No. 92	

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Louisville Gas and Electric Company

Standard Rate **VFD**
Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation or personal vehicle fueling shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Company's Terms and Conditions. Additionally, service for gas for use in standby electric generation and personal vehicle fueling shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers. **T**

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:
1) having at least 12 members and a chief,
2) having at least one fire fighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge per month:	$24.00 per delivery point	**T/I**
Plus a Distribution Charge per 100 cubic feet:	$ 0.25385	**T/R D**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	**T**
Gas Supply Clause	Sheet No. 85	
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **VFD**
Volunteer Fire Department Service

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month’s charges.

TERMS AND CONDITIONS
Service will be furnished under Company’s Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **CGS**

Firm Commercial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term “commercial” customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Company’s Terms and Conditions. Additionally, service for **T**
gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate **CGS**

Firm Commercial Gas Service

RATE

Basic Service Charge per month:		T
If all of the customer's meters have a capacity < 5000 cf/hr:	$ 60.00 per delivery point	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$285.00 per delivery point	I
Plus a Distribution Charge per 100 cubic feet:	$ 0.26267	T/I D

Off-Peak Pricing Provision:
The Distribution Charge applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above. T

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE T

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **IGS**
Firm Industrial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term “industrial” customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, vehicular fueling of internal combustion engines, and for other similar uses. Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Company’s Terms and Conditions. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers. **T**

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate **IGS**
Firm Industrial Gas Service

RATE

Basic Service Charge per month:		T
If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 165.00 per delivery point	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$750.00 per delivery point	I
Plus a Distribution Charge per 100 cubic feet:	\$ 0.21929	T/R D

Off-Peak Pricing Provision:
The Distribution Charge applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by \$0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above. T

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DATE OF ISSUE: November 23, 2016

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State Regulation and Rates
Louisville, Kentucky

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DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

Standard Rate **AAGS**

As-Available Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the provisions of this rate schedule. **T**

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual delivery point. **T**

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual delivery point. Customers not electing service under either Rate CGS or Rate IGS shall **T** receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in “Contract-Term” below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE

Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM

Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on

Louisville Gas and Electric Company

Standard Rate **AAGS**
As-Available Gas Service

CONTRACT TERM (continued)
November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

RATE

Basic Service Charge per month:	$500.00 per delivery point	**T/I**
Plus a Distribution Charge per Mcf:	$1.0644	**T/I** **D**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	**T**
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

PENALTY FOR FAILURE TO INTERRUPT
Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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PENALTY FOR FAILURE TO INTERRUPT (continued)

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on “Contract Term”, and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge applicable to any unauthorized takes of gas during the period of interruption (excluding Pilot Light Requirements where applicable) equal to $15.00 plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the period of interruption that falls into each monthly billing cycle, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the period of interruption that falls into each monthly billing cycle. Such penalty for failure to interrupt shall be in addition to any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T**

2. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules. **T**

3. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder. **T**

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

4. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer. **T**

5. Customer shall discontinue taking service upon applicable notice by Company to do so. **T**

6. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption. **T**

7. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS. **T**

8. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules. **T**

9. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder. **T**

10. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at any time thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall reimburse Company for the cost of the remote metering equipment, for any modifications to Company facilities, and for the replacement of any existing meters required in order to facilitate the functioning of the remote metering. **T**

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State Regulation and Rates
Louisville, Kentucky

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SPECIAL TERMS AND CONDITIONS (continued)

Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

D

Standard Rate **SGSS**
Substitute Gas Sales Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is required for any commercial or industrial customer that is physically connected to the facilities of any other provider of natural gas, bio-gas, native gas, methane, or other gaseous fuels, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. In the event that such Customer desires to continue to receive natural gas service from Company and/or declines to allow Company to remove Company's facilities hitherto used to provide natural gas service to Customer, then Customer shall be obligated to take service under Rate SGSS.

Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

Company may decline to serve customers using gas to generate electricity in standby or other applications under this rate schedule.

Customers shall be classified as commercial or industrial in accordance with the definitions set forth in either Rate CGS or Rate IGS, as applicable to customer's primary gas use.

RATE
For commercial customers, the following charges shall apply:

Basic Service Charge per month:	$285.00 per delivery point
Plus a Demand Charge:	$6.27 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.3767 per Mcf delivered

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State Regulation and Rates
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RATE (continued)

For industrial customers, the following charges shall apply:

Basic Service Charge per month:	$750.00 per delivery point
Plus a Demand Charge:	$10.90 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.2992 per Mcf delivered

MAXIMUM DAILY QUANTITY

Company shall provide firm natural gas sales service to Customer at a single Point of Delivery up to the Maximum Daily Quantity ("MDQ"). Customer and Company may mutually agree to establish the level of the MDQ; provided, however, that in the event that Customer and Company cannot agree upon the MDQ, then the level of the MDQ shall be equal to the highest daily volume used by Customer during the twelve (12) months prior to the date that Customer began receiving natural gas from another supplier with which Customer is physically connected; in the event that such daily gas usage is not available, then the MDQ shall be equal to the Customer's average daily use for the highest month's gas use in the twelve (12) months prior to the date that Customer began receiving natural gas from another supplier with which Customer is physically connected; in no case shall the MDQ be greater than 5,000 Mcf/day.

Service by Company to Customer in excess of the MDQ shall be provided by Company on an interruptible basis. The maximum hourly volume that Company shall be obligated to deliver to Customer shall not exceed 1/16th of the MDQ.

MONTHLY BILLING DEMAND

The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered during the current month or the previous eleven (11) monthly billing periods. The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

Regardless of the Monthly Billing Demand established by Customer, Company's obligation to provide firm natural gas sales service up to the MDQ shall be limited to the MDQ.

MINIMUM CHARGE

The minimum monthly bill shall be equal to all of the charges under this rate schedule, including, but not limited to, the basic service charge, the monthly demand charge, any volumetric charges, and any adjustment clauses.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Gas Supply Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

2. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the MDQ, Delivery Point, delivery pressure, and any other matters relating to individual Customer circumstances.

3. On no day shall Company be obligated to supply gas in excess of Customer's MDQ. In order to effectuate Company's obligation, Company may install such remote flow equipment as it determines to be necessary in order to control and limit the amount of gas taken by Customer from Company, such facilities to be installed by Company at Customer's expense.

4. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

5. Any Customer contracting for service hereunder shall be required, prior to commencing service hereunder, to have appropriate remote metering devices. The remote metering devices allow Company to monitor Customer's usage. The Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering. Company may also install at Customer's expense, any backflow protection devices and/or flow control equipment as may be required in sole discretion of Company. The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering or other facilities determined to be the

SPECIAL TERMS AND CONDITIONS (continued)

installation and operation of such remote metering or other facilities determined to be necessary by Company. The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

6. Company will have the right to curtail or interrupt the delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

TERM OF CONTRACT

The minimum term for service hereunder shall be for a period of one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of MDQ or other special circumstances. After the expiration of the primary term, the contract may be terminated by either Company or Customer upon one year's prior written notice.

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV.

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the provisions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers. **T**

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity ("MDQ") in excess of 20,000 Mcf/day. In the event that Customer's MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rate schedule.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Standard Rate **FT**

Firm Transportation Service (Transportation Only)

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 7 of the Special Terms and Conditions. **T**

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply: **T**

Administrative Charge per month:	$550.00 per Delivery Point	**T**
Plus a Distribution Charge per Mcf:	$ 0.4428	**T/I**

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected **T**

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State Regulation and Rates
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RATE (continued)

in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings. **T**

For customers electing service under Rate FT effective November 1, 2015, the Gas Cost True-Up Charge shall be:

$(0.0375) per Mcf for Bills Rendered On and After November 1, 2016

For customers electing service under Rate FT effective November 1, 2016, the Gas Cost True-Up Charge shall be:

$0.0467 per Mcf for Bills Rendered On and After November 1, 2016

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula:

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

Payment of the Minimum Daily Threshold Charge is not a remedy for Customer's failure to meet the Minimum Daily Threshold Requirement for service under Rate FT. In the event that Customer does not meet the Minimum Daily Threshold Requirement for one-hundred twenty (120) days during a given Contract Year, service to Customer under Rate FT may be discontinued by Company. Customer will receive thirty (30) days prior written notice that Customer will be removed from Rate FT and returned to firm sales service under either Rate CGS or IGS as applicable.

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RATE (continued)

Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month’s charges.

IMBALANCES

Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

$$\text{Imbalance} = \text{Metered Usage} - \text{Delivered Volume}$$

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Metered Usage} - \text{Delivered Volumes})}{\text{Delivered Volume}}$$

The term “day” or “daily” shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

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State Regulation and Rates
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The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer’s estimated deliveries by Pipeline Transporter occurs through the operation of the cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

UTILIZATION CHARGE FOR DAILY IMBALANCES (continued)

Daily Demand Charge:	$0.1608 per Mcf	
Daily Storage Charge:	0.2785	I
Utilization Charge for Daily Imbalances:	$0.4393 per Mcf	I

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume unless an OFO has been issued. If an OFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable and further described below under “Operational Flow Orders.” Customers not in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order (“OFO”) which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect and shall include information related to the OFO. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool, it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that

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OPERATIONAL FLOW ORDERS (continued)

is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Unauthorized receipts or deliveries during the effectiveness of an OFO shall be subject to an OFO Charge per Mcf for each Mcf of unauthorized receipts or deliveries, as applicable. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge per Mcf shall be equal to $15.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated. Such OFO Charge shall be in addition to any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

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RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions **T**
applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor **T**
inconsistent, with the specific provisions hereof. **T**

2. Service under this rate schedule shall be performed under a written contract between Customer **T**
and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances.

3. As further described below, Customer shall specify to Company the daily volume of gas required **T**
by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. **T**

SPECIAL TERMS AND CONDITIONS (continued)

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service. **T**

4. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The maximum hourly volume that Company shall be obligated to deliver shall not exceed 1/24th of the MDQ. The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis. **T T T**

5. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Company's Terms and Conditions. **T T**

6. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter. **T**

7. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition. **T**

8. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements. **T**

9. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the provisions of this rate schedule. **T**

10. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data. **T T**

D

Standard Rate **DGGS**

Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE

Gas sales service under this rate schedule shall be considered firm.

Louisville Gas and Electric Company

Standard Rate **DGGS**
Distributed Generation Gas Service

RATE

In addition to any other charges set forth herein, the following charges shall apply: **T**

Basic Service Charge per month:		**T**
If all of the customer's meters have a capacity < 5000 cf/hr:	$ 165.00 per delivery point	**I**
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$750.00 per delivery point	**I**
Plus a Demand Charge:	$ 1.08978 per 100 cubic feet of Monthly Billing Demand	**T/R**
Plus a Distribution Charge:	$ 0.02992 per 100 cubic feet	**T/R** **D**

The total monthly minimum bill shall be the sum of the minimum Demand Charge and the Basic Service Charge. **T**

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity ("MDQ"), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	**T**
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate **DGGS**
Distributed Generation Gas Service

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T**

2. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances. **T**

3. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof. **T**

4. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate ("MHR"), and the maximum daily quantity ("MDQ"). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer's installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf. **T**

5. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less. **T**

6. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract. **T**

7. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company. **T**

D

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State Regulation and Rates
Louisville, Kentucky

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APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rate schedule is available to any party who contracts with Company to provide firm transportation service of local gas (including landfill gas, bio-gas, synthetic gas, and locally produced natural gas) where and when such transportation will not, in the sole discretion of Company, interfere with the operation of Company's storage or other facilities, or the delivery of gas to Company's retail sales or end-use gas transportation customers. Customer must meet the eligibility requirements further described hereunder and shall deliver gas meeting the gas quality standards incorporated into this rate schedule.

Customer shall request Company to utilize its system to transport, by displacement, such local gas to the Delivery Point. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Company shall not be required to install any facilities of any kind to serve a Customer under this rate schedule. In the event that Company is agreeable to the installation or alteration of any facilities as may be required to serve Customer, then Customer shall execute a separate contract for the construction of such facilities and shall pay for all costs of those facilities. Company shall not be obligated to extend its mains to facilitate service hereunder. Company's "Gas Main Extension Rules" shall not apply to service under this rate schedule.

Company and Customer shall enter into an Interconnect Facility Agreement covering the design, ownership, operation, and maintenance of the Interconnect Facility, including, but not limited to, any cost reimbursement provisions. Company shall own and operate the Interconnect Facility (including, but not limited to, regulation, meters, chromatograph, control valves, taps, insulators, rights-of-way, and related facilities) as are required to effectuate service hereunder. The Interconnect Facility shall be designed and constructed in accordance with Company's specifications. Company shall own and install facilities downstream of the Interconnect Facility required to connect the Interconnect Facility to Company's mainline gas system. Company shall be reimbursed by Customer for the costs of such downstream facilities and their installation as well as the costs to construct, operate, and maintain the Interconnect Facility. Customer may be required by Company to provide adequate surety to cover the costs incurred by Company related to either the Interconnect Facility or the related downstream facilities. The outlet of the Interconnect Facility shall be the Receipt Point as the latter term is used herein.

Customer shall warrant, in its Service Agreement, that all gas transported under this rate schedule shall be consumed within the Commonwealth of Kentucky. If Customer is unable to warrant that such gas is so consumed, then Company's transportation service shall be deemed interstate service and may only be provided pursuant to authorization from the Federal Energy Regulatory Commission ("FERC") and subject to the terms and conditions of Company's Statement of Operating Conditions as filed with FERC. Customer shall not be allowed to combine interstate services with intrastate services. Any Customer requesting interstate and intrastate transportation service shall have separate contracts for each activity. Only one service, either interstate service or intrastate service, shall apply to a Receipt Point.

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point to the Delivery Point. The Delivery Point shall be a pool operating under either Rider PS-TS-2 or Rider PS-FT. Company shall receive gas from Customer for transportation at the Receipt Point and deliver that gas by displacement to the Delivery Point. Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver a volume of gas to the Delivery Point, either daily or monthly, which differs from the volume of gas delivered to Company at the Receipt Point. Company will provide service to meet imbalances only on an as-available basis, as set forth herein.

Company shall not be obligated to deliver gas to the Delivery Point in excess of the Maximum Daily Quantity ("MDQ") as further defined herein. Customer and Company shall mutually agree to establish the level of the MDQ; provided, however, that the MDQ shall not be less than 50 Mcf/day.

Company may decline to deliver volumes to the Delivery Point in excess of the MDQ or accept volumes from the Receipt Point that are in excess of the MDQ plus applicable Lost and Unaccounted for Gas ("LAUFG") as further defined herein.

Company may deliver volumes of gas to the Delivery Point in excess of the MDQ; provided, however, that such deliveries to the Delivery Point in excess of the MDQ shall establish a new Monthly Billing Demand as further defined herein. Regardless of the Monthly Billing Demand established by Customer, Company's obligation to provide firm natural gas transportation service shall be limited to the MDQ.

Volumes shall be delivered by Customer to Company at the Receipt Point as nearly as practicable at uniform daily rates of flow, that is, 1/24th of the daily Gross Nominated Volume as further defined herein.

RATE

Administrative Charge per month:	$550.00 per Receipt Point
Plus a Basic Service Charge per month:	$1,310.00 per Receipt Point
Plus a Demand Charge:	$2.57 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.0388 per Mcf of Net Nominated Volumes at the Delivery Point

The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered to the Delivery Point during the current month or the previous eleven (11) monthly billing periods.

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Company's Pipeline Transporter(s), then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

MAXIMUM DAILY QUANTITY, NOMINATIONS AND NOMINATED VOLUMES

The MDQ shall represent the maximum volume which Customer shall be entitled to nominate and Company shall be obligated to deliver to the Delivery Point.

As further described below, Customer shall specify to Company the daily volumes of gas to be received at the Receipt Point (the "Gross Nominated Volume"). From such Gross Nominated Volume shall be deducted an allowance for Company's system average LAUFG expressed as a percentage and based on historical levels. Effective November 1, 2016, such LAUFG percentage is 2.69%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to Customer at least thirty (30) days prior to such November 1.

The Net Nominated Volume (the Gross Nominated Volume less applicable LAUFG) shall be stated in Mcf/day and converted to MMBtu/day using the conversion factor specified by Company. The Net Nominated Volume is the amount that shall be delivered to the Delivery Point.

For example, if Customer requests Company to receive 342 Mcf on a given day at the Receipt Point (the Gross Nominated Volume), and the LAUFG percentage is 5.0%, then the Net Nominated Volume shall be 325 Mcf [342 – (342 x 0.05)]. The Net Nominated Volume of 325 Mcf shall be converted to MMBtu using the conversion factor specified by Company.

At least ten (10) days prior to the beginning of each calendar month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the month. Any changes in daily nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time ("ECT") on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled at the Delivery Point by an authorized Pool Manager are considered Net Nominated Volumes. Company shall not be obligated to accept from Customer daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays observed by Company.

Customer shall submit in writing to Company the daily nominated volumes and such other information as may be required to effectuate the transportation of natural gas by using the appropriate Nomination Schedule as may be specified by Company from time to time and by giving appropriate notice as designated by Company.

Customer agrees to inform Company promptly of any changes in the delivery rate to Company of gas transported under this rate schedule or any other information with regard to scheduling of deliveries that Company reasonably requests or as may be required by proper regulatory authorities.

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State Regulation and Rates
Louisville, Kentucky

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LOCAL GAS FLOW ORDERS

Company shall have the right to issue a Local Gas Flow Order ("LGFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the LGFO.

Notice of an LGFO shall be provided to Customer at least four (4) hours prior to the beginning of the gas day for which the LGFO is in effect and shall include information related to the LGFO. A shorter notice period may be given where necessary to protect the integrity of Company's gas system. Customer shall respond to an LGFO by adjusting its deliveries to Company's system as directed in the LGFO within the specified timeframe.

Upon issuance of an LGFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must nominate at the Receipt Point a Gross Nominated Volume that is no more than the daily amount being received by Company from Customer at the Receipt Point (Metered Receipts); or (b) Customer must nominate at the Receipt Point a Gross Nominated Volume that is no less than the daily amount being received by Company from Customer at the Receipt Point (Metered Receipts). Customer shall respond to an LGFO either by adjusting its Gross Nominated Volume at the Receipt Point or by adjusting volumes being received by Company from Customer at the Receipt Point. All volumes nominated by Customer at the Receipt Point in excess of volumes received by Company from Customer at the Receipt Point in violation of the above "condition (a)" LGFO shall constitute an unauthorized under-delivery by Customer to Company at the Receipt Point. All volumes nominated by Customer at the Receipt Point less than volumes received by Company from Customer at the Receipt Point in violation of the above "condition (b)" LGFO shall constitute an unauthorized over-delivery from Customer to Company at the Receipt Point. Unauthorized under-deliveries or over-deliveries during the effectiveness of an LGFO shall be subject to an LGFO Charge per Mcf for each Mcf of unauthorized under-deliveries or over-deliveries, as applicable. Customer shall be subject to the LGFO Charge on the day for which the LGFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized under-deliveries or over-deliveries that occur.

Company may, in its sole discretion, issue an LGFO to an individual Customer taking service under this rate schedule without issuing an LGFO to all Customers taking service under this rate schedule.

The LGFO Charge per Mcf shall be equal to $15.00 plus the higher of either (a) the daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the LGFO was violated, or (b) the daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the LGFO was violated. Such LGFO Charge shall be in addition to any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule if Customer does not comply with the terms or conditions of an LGFO. Payment of LGFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the LGFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company. As a result of Customer's failure to comply with the terms or conditions of service, including an LGFO, Company may take such actions as it deems necessary to suspend service to Customer.

If Customer fails to manage its use of Company's transportation service in strict conformance with the directives of an LGFO, then Company may at its sole discretion do one or more of the following immediately upon delivering oral or written notice to Customer: (1) suspend all gas transportation service to the extent necessary to protect the operational integrity of Company's system, (2) decline to deliver to the extent necessary the gas provided by Customer, (3) decline to receive to the extent necessary the volume tendered by Customer at the Receipt Point, and (4) permanently terminate service under this rate schedule. Any suspension or termination under this section shall be without prejudice to and in addition to any other rights and remedies of Company.

IMBALANCES

The terms "Imbalance" or "Imbalances" as used herein mean the difference between Customer's Gross Nominated Volume in Mcf of gas to be received by Company at the Receipt Point and the metered volume of gas in Mcf actually received by Company from Customer at the Receipt Point (Metered Receipts).

When Company can provide such balancing service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of +/-5% of the Gross Nominated Volume. Company shall issue an LGFO as set forth herein during periods when service cannot be provided to meet daily imbalances.

Company shall calculate on a daily and monthly basis Customer's imbalance resulting from the difference between Customer's Gross Nominated Volume in Mcf for receipt by Company at the Receipt Point and the Metered Receipts of gas in Mcf from Customer at the Receipt Point. This will be calculated as follows:

$$\text{Imbalance} = \text{Gross Nominated Volumes} - \text{Metered Receipts}$$

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Gross Nominated Volumes} - \text{Metered Receipts})}{\text{Gross Nominated Volumes}}$$

The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by Company.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤ 5%	100%
> 5% to ≤ 10%	90%
>10% to ≤ 15%	80%
>15% to ≤ 20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

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State Regulation and Rates
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The appropriate percentage shall be dependent on Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to $\leq$ 5%	100%
> 5% to $\leq$ 10%	110%
>10% to $\leq$ 15%	120%
>15% to $\leq$ 20%	130%
>20%	140%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to $\leq$ 5%	100%
> 5% to $\leq$ 10%	110%
>10% to $\leq$ 15%	120%
>15% to $\leq$ 20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such cash-out charges or credits, as applicable, shall be shown and included on Customer's monthly bill. The billing of these cash-out charges or credits shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATION IN MMBTU CONTENT

The reconciliation of the actual deliveries to the Delivery Point and Company's receipt of gas from Customer at the Receipt Point, including any variation in MMBtu content, occurs through the operation of the cash-out provision. If not reflected on the current month's bill, changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following month's bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance as calculated herein exceed +/- 5% of the Gross Nominated Volume on any day when an LGFO (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the imbalance in Mcf greater than +/- 5% of Gross Nominated Volume for each daily occurrence.

The Utilization Charge for Daily Imbalances is the sum of the following:

Daily Demand Charge:	\$0.1608 per Mcf
Daily Storage Charge:	0.2785
Utilization Charge for Daily Imbalances:	\$0.4393 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed the +/- 5% unless an LGFO has been issued. If an LGFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the LGFO directive, either "condition (a)" or "condition (b)" as applicable and further described above under "Local Gas Flow Orders". Customers not in violation of the LGFO directive, either "condition (a)" or "condition (b)" as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

MEASUREMENT OF GAS

Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Company's Terms and Conditions. All gas delivered by Customer to Company pursuant to this rate schedule shall be measured by Company using such gas meters, chromatograph, and other instrumentation as Company deems appropriate.

REMOTE METERING

Any Customer contracting for service hereunder shall be required, prior to commencing service hereunder, to have appropriate remote metering devices. The remote metering devices allow Company to monitor receipts of gas from Customer.

Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities required in order to facilitate the functioning of the remote metering. Company may also install at Customer's expense, any backflow protection devices, remote flow equipment, and the like, as may be required in sole discretion of Company, in order to protect the integrity of Company's gas system. Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering or other facilities determined to be necessary by Company. Customer shall be responsible for providing the necessary and adequate electric and telecommunications service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. Customer shall be responsible for maintaining the necessary and adequate electric and telecommunications service to provide remote metering.

GAS QUALITY

Gas received hereunder shall be merchantable gas, commercially free from toxins, odors, dust, solids, gums, gum-forming constituents, gasoline, water, or any other foreign substances of any kind, including liquid matter and hydrocarbon liquids which may become separated from the gas in the course of transportation through Company's system, and which might interfere with its merchantability or cause injury to or interference with proper operation of lines, regulators, meters, or other appliances.

Furthermore, such receipts shall not contain, either in the gas or in any liquids with the gas, any microbiological organism, pathogen, active bacteria, or bacterial agent capable of producing or contributing to corrosion, operational problems, or other problems, or are injurious to utility facilities or cause the gas to be unmarketable. Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria and acid producing bacteria.

Customer agrees that it will indemnify Company and save it harmless from all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of any claim by any other persons or entity related to or arising from gas tendered by Customer to Company not meeting the quality specifications herein.

If the gas tendered by Customer for transport by Company fails at any time to conform to any of the specifications set forth herein, then Company shall so notify Customer and Company may, at its sole option and in addition to any other remedies available to Company, refuse to accept delivery pending correction by Customer.

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State Regulation and Rates
Louisville, Kentucky

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2016-00371 dated xxxx

Standard Rate

LGDS
Local Gas Delivery Service

The table below sets forth the applicable specifications for the gas received hereunder by Company from Customer.

Component	Units	Low	High
Total Heating Value	Btu per scf	967	1110
Wobbe Index	Calculated by dividing the Total Heating Value (dry) of the gas (at standard conditions of 14.73 psia and 60 degrees Fahrenheit) by the square root of the specific gravity of the gas	1314	1400
Carbon Dioxide	Percent by volume (mole%)	0.00%	2.00%
Hydrogen	Percent by volume (mole%)	0.00%	0.00%
Water (or water vapor)	lbs. per MMscf	0	7
Ammonia	ppm	0	3
Hydrogen Sulfide	grains per 100 scf	0	0.25
Total Sulphur (not including any mercaptan sulphur)	grains per 100 scf	0	5
Oxygen	Percent by volume (mole%)	0.00%	0.10%
All non-hydrocarbon gases such as carbon dioxide, nitrogen, and oxygen (Total Diluténts and Inerts)	Percent by volume (mole%)	0.00%	4.00%
Non-methane Hydrocarbons (C2+) such as ethane	Percent by volume (mole%)	0.00%	12.00%
Heavier Hydrocarbons (C3, C4, C6, +) such as propane, propylene, butanes, hexanes	Percent by volume (mole%)	0.00%	1.50%
Delivery Temperature	degrees Fahrenheit	40	90
Hydrocarbon Dewpoint	degrees Fahrenheit	Less than 10	

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Company shall have the unqualified right to commingle gas received for service hereunder with gas from other sources. Accordingly, gas received by Company shall be subject to such changes as may result from such commingling and Company shall, notwithstanding any other provisions herein, be under no obligation to deliver for Customer's account gas identical to that received by Company.

CREDITWORTHINESS

Customer shall upon request of Company agree to maintain an irrevocable letter of credit, cash prepayment, or such other financial instrument satisfactory to Company ("credit support") in order to assure Customer's performance of its obligations hereunder. In determining the level of the security to be required of Customer, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customer, the MDQ, the general creditworthiness of Customer, and Customer's prior credit record with Company, if any. The amount of the credit support shall not exceed two twelfths (2/12) of Customer's estimated annual bill. In the event that Customer defaults on its obligations under this rate schedule, Company shall have the immediate right to draw on such credit support to satisfy Customer's obligation hereunder. Such credit requirements shall be administered by Company in a nondiscriminatory manner.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

2. Service under this rate schedule shall be performed under a written contract between Customer and Company ("Service Agreement") which shall set forth specific arrangements as to the MDQ, volumes to be transported, Receipt Point, Delivery Point, Receipt Pressure, timing of receipts and deliveries of gas by Company, term, and any other matters relating to individual Customer circumstances.

3. Should Customer be unable to provide an amount of gas to Company at the Receipt Point equivalent to the Gross Nominated Volume (the Net Nominated Volume plus applicable LAUFG), Company will not be obligated hereunder to provide standby quantities of gas. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

4. Company will have the right to curtail or interrupt the delivery of gas hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

5. It is at all times the responsibility of Customer to deliver gas to the Receipt Point at a pressure ("Receipt Pressure") sufficient to cause the delivery of gas into the system of Company. Company shall not be obligated to modify either its facilities or its prevailing system operating pressures in order to effectuate the receipt of gas from Customer at the Receipt Point.

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SPECIAL TERMS AND CONDITIONS

6. Customer hereby agrees to reimburse Company for all Kentucky sales tax, if any, assessed on the charges specified in this rate schedule. Customer's Kentucky Sales Tax Permit Account Number shall be provided to Company pursuant to Company's request.

7. As between Company and Customer, Customer shall be in exclusive control and possession of the gas until such gas has been delivered to Company at the Receipt Point and after such gas has been delivered to the Delivery Point. Company shall be in exclusive control and possession of such gas while it is in Company's system between the Receipt Point and the Delivery Point. Company shall have no liability while the gas is in the exclusive control of Customer and Customer shall have no liability (except for damage, loss, or injury caused by Company's transportation of gas that does not meet the quality standards set forth herein or that is delivered to Company in violation of any other provision of this Rate Schedule) while the gas is in the exclusive control of Company. Title to all gas delivered by Customer to Company for transportation under this rate schedule shall remain with Customer at all times during transportation by Company. Company shall not acquire or take title to the gas transported hereunder with the exception of any over-deliveries purchased through the operation of the cash-out mechanism described hereunder.

8. In no event shall Company be liable to Customer for consequential, indirect, special, punitive, or exemplary damages arising out of service provided hereunder.

9. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data.

TERM OF CONTRACT

The minimum term for service hereunder shall be for a period of one (1) year or through the following October 31, whichever period is shorter. Company, in its sole discretion, may require that a contract be executed for a longer initial term when deemed necessary by the size of MDQ or other special circumstances. After such initial term, service under this rate schedule automatically shall continue in full force and effect and from year to year (from November 1 through October 31, which period shall be defined as a "Contract Year"), until terminated by either Party hereto for any reason, or no reason, pursuant to written notice of termination given by one Party to the other Party by the April 30th prior to the next available November 1st termination date.

When the Parties have agreed upon the terms required to complete the contract for service hereunder, Company shall tender a Service Agreement to Customer reflecting such agreed upon terms. The Service Agreement shall be invalid unless signed by the requesting Party and returned to Company within thirty (30) days after Company provides such Service Agreement to Customer for execution.

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a Customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a Customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1, the Customer will be charged $90.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Rate Schedules RGS, VFD, CGS, IGS, and AAGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. Customers taking service under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of service. **T**

INSPECTION CHARGE

With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $150.00 will be made for each additional trip.

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State Regulation and Rates
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Louisville Gas and Electric Company

Special Charges

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

UNAUTHORIZED RECONNECT CHARGE N

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

2. A charge of $132.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a meter.

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Standard Rate Rider **TS-2**

Gas Transportation Service/Firm Balancing Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 15,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. **T**

In addition, transportation service hereunder will be subject to the provisions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers. **T**

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

Louisville Gas and Electric Company

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 7 of the Special Terms and Conditions. **T**

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a third-party TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge per month: $550.00 per Delivery Point **T**

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.6267	$2.1929	$1.0644	**I/R/I**
Pipeline Supplier's Demand Component	0.8392	0.8392	0.8392	
Total	$3.4659	$3.0321	$1.9036	**I/R/I**

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State Regulation and Rates
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Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

RATE (continued)

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rate FT. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rider TS-2 effective November 1, 2015, the Gas Cost True-Up Charge shall be:

$(0.0375) per Mcf for Bills Rendered On and After November 1, 2016

For customers electing service under Rider TS-2 effective November 1, 2016, the Gas Cost True-Up Charge shall be:

$0.0467 per Mcf for Bills Rendered On and After November 1, 2016

Minimum Annual Threshold Requirement and Charge: When Customer's annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 15,000 Mcf and the Customer's actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer's Annual Usage) times the Peak Period Distribution Charge

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RATE (continued)

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Optional Monthly Telemetry Charge: $300.00 per Delivery Point per month

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

At the time that the Customer executes a contract for service hereunder, Customer shall elect to either (1) pay for the cost of this remote metering equipment and the cost of its installation in an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified herein. Under either option, Customer shall reimburse Company for the cost of any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that Customer's service under Rider TS-2 becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

Louisville Gas and Electric Company

SPECIAL TERMS AND CONDITIONS

1. Service under this rider will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T**

2. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances. **T**

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in Rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

3. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The maximum hourly volume that Company shall be obligated to deliver shall not exceed 1/24th of the MDQ. The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis. **T T T**

SPECIAL TERMS AND CONDITIONS (continued)

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Company's Terms and Conditions. **T** **T**

5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter. **T**

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition. **T**

7. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural gas hereunder. **T**

8. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data. **T** **T**

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Standard Rate Rider **GMPS**
Gas Meter Pulse Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater.

CHARACTER OF SERVICE
The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer.

For customers served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer.

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and 10 mA or less, or as otherwise determined by the **T**

CHARACTER OF SERVICE (continued)

Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements. **T**

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply: **T**

For Customers Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $ 7.17

For Customers Not Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $24.34

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T** **T** **T**

2. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment. **T**

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

3. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes. **T**

4. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment. **T**

5. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice. **T**

6. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose. **T**

7. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost. **T**

8. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder. **T**

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a "TS-2 Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A customer served under Rider TS-2 must join a Rider PS-TS-2 pool managed by a third-party Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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ACTION ALERTS

Company shall have the right to issue an Action Alert (“AA”) which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. It is the responsibility of the Pool Manager, not Company, to convey an AA to Customers in its TS-2 Pool. Pool Manager shall be responsible for complying with the directives contained in the AA.

Notice of an AA shall be provided to TS-2 Pool Manager at least eighteen (18) hours prior to the beginning of the gas day for which the AA is in effect. TS-2 Pool Manager shall respond to an AA by adjusting its deliveries to Company's system as directed in the AA within the specified timeframe.

Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Each Mcf delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge.

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge per Mcf shall be equal to $5.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the AA was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the AA was violated. Such Action Alert Charge shall be in addition to any other charges under this rider.

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

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State Regulation and Rates
Louisville, Kentucky

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IMBALANCES

Company will calculate on a daily and monthly basis the TS-2 Pool Manager’s imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

$$\text{Imbalance} = \text{Metered Usage} - \text{Delivered Volumes}$$

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Metered Usage} - \text{Delivered Volumes})}{\text{Delivered Volumes}}$$

The term “day” or “daily” shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

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State Regulation and Rates
Louisville, Kentucky

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NOMINATIONS AND NOMINATED VOLUME (continued)

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2016, such LAUFG percentage is 2.69%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG percentage is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SUPPLIER CODE OF CONDUCT

Each PS-TS-2 Pool Manager participating in the Company's transportation program under Rider PS-TS-2 must:

1. communicate to participating Customers in clear, understandable terms the Customer's rights and responsibilities. This communication must include (a) the PS-TS-2 Pool Manager's customer service address and local or toll-free telephone number; and (b) a statement describing the PS-TS-2 Pool Manager's dispute resolution procedures;

2. provide in writing pricing and payment terms that are clearly defined and understandable and that inform consumers whether the price that the Customer will pay is inclusive or exclusive of applicable taxes, and Company approved tariff riders and surcharges;

3. refrain from engaging in communications or promotional practices which are fraudulent, deceptive, or misleading;

4. deliver gas to the Company on a firm basis on behalf of the Customers enrolled in the PS-TS-2 Pool Manager's pool in accordance with the requirements of the PS-TS-2 Pool Management Agreement;

SUPPLIER CODE OF CONDUCT

5. establish and maintain a credit-worthy financial position that enables PS-TS-2 Pool Manager to indemnify the Company and the Customers for costs incurred as a result of any failure by the PS-TS-2 Pool Manager to deliver gas in accordance with the requirements of Rider PS-TS-2 and to assure payment of any applicable charges for any such failure;

6. refrain from requesting customer-specific billing, payment, and usage history without first having received the Customer's written approval allowing PS-TS-2 Pool Manager to access such information.

Failure to fulfill any of these obligations shall be considered a violation of the Supplier Code of Conduct.

If the PS-TS-2 Pool Manager fails to comply with the Supplier Code of Conduct, the Company will have the discretion to temporarily suspend or terminate such PS-TS-2 Pool Manager from further participation in the transportation program under Rider PS-TS-2. If service to the PS-TS-2 Pool Manager is suspended or terminated, Customer(s) in the PS-TS-2 Pool Manager's Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS) until said Customer(s) join another PS-TS-2 Pool Manager's Pool. If the Company seeks to suspend or terminate service to a PS-TS-2 Pool Manager, Company shall first notify the PS-TS-2 Pool Manager of the alleged violations which merit suspension or termination. Such notice must be in writing and must be sent to the PS-TS-2 Pool Manager as specified in the notice provisions of the PS-TS-2 Pool Management Agreement at least five (5) business days prior to the effective date of the suspension or termination.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.

2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

SPECIAL TERMS AND CONDITIONS (continued)

The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

3. The TS-2 Pool Manager shall upon request of Company agree to maintain an irrevocable letter **T**
of credit or such other financial instrument satisfactory to Company in order to assure TS-2 Pool **T**
Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

   Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool.

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State Regulation and Rates
Louisville, Kentucky

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SPECIAL TERMS AND CONDITIONS (continued)

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.

6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.

7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

8. Pool Manager shall enter into a Website Subscriber Agreement if Pool Manager desires to access **T**
telemetry data. **T**

Standard Rate Rider **PS-FT**

Pooling Service – Rate FT

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to "FT Pool Managers".

For the purpose of this rider, a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE

In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager:

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool.

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT.

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State Regulation and Rates
Louisville, Kentucky

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CHARACTER OF SERVICE (continued)

Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

   The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) days prior to the end of a billing period.

   The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

SPECIAL TERMS AND CONDITIONS (continued) **T**

3. The FT Pool Manager shall upon request of Company agree to maintain an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT.

8. Pool Manager shall enter into a Website Subscriber Agreement if Pool Manager desires to access telemetry data. **T** **T**

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to main extensions or to other facilities which are necessary to provide basic gas service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES

Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

EXCESS FACILITIES CHARGE

Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With No Contribution-in-Aid-of-Construction 1.24%

(b) making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With Contribution-in-Aid-of-Construction 0.47%

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PAYMENT

The Excess Facilities Charges shall be incorporated with the bill for gas service and will be subject to the same payment provisions.

TERM OF CONTRACT

The initial term of contract to Customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

Standard Rate Rider **NGV**
Natural Gas Vehicle Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under **T**
this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than as natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or **T**
boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

CHARACTER OF SERVICE
Company will provide Customer with uncompressed natural gas pursuant to either Rate IGS or Rate FT, as applicable. A customer served under Rate IGS that meets the qualifications for service under Rider TS-2 may also transport gas pursuant to Rider TS-2.

Customer shall be responsible for installing, owning, and maintaining all facilities required to operate its fueling station.

The compression of natural gas to the pressure required for use as a motor vehicle fuel will be conducted by Customer using facilities installed, owned and operated by Customer.

RATE
The rates, provisions, and special terms and conditions of Rate IGS, Rider TS-2, or Rate FT as applicable to the Customer shall apply.

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate Rider **NGV**
Natural Gas Vehicle Service

SPECIAL TERMS AND CONDITIONS **T**

1. Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T T**

2. Company reserves the right to inspect customer's premises to ensure gas provided pursuant to this Rider is only used for vehicular fuel. Any other use of gas by Customer may result in termination of service. **T**

3. Service under this Rider shall be performed under a written contract between Customer and Company containing such provisions regarding delivery pressure, indemnification, and other matters as the Company deems necessary or desirable with respect to a particular customer. **T**

4. Customer shall be responsible for and shall reimburse the Company for all taxes (including, but not limited to, any motor vehicle taxes) payable by the Company to any governmental body on sales of gas and/or for services rendered under this Rider. Customer shall be solely responsible for the reporting and payment of all applicable federal and state motor fuel taxes including, but not limited to, any federal special fuel excise tax and any state motor fuel tax. **T T T T**

5. The Resale of Gas provision set forth in the Company's Terms and Conditions shall not apply to service provided under this Rider. Customer may resell gas received from Company under this Rider for use as a fuel in vehicular internal combustion engines. **T**

6. Customer is solely responsible for compliance with codes and standards, permitting requirements, regulations, and laws related to the use of compressed natural gas and the operation of a natural gas vehicle fueling station, whether as a fleet operation or as a public fueling station. Company is not responsible for vehicle fueling. **T**

D

Adjustment Clause **GLT**
Gas Line Tracker

APPLICABLE

Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, FT, SGSS, DGGS, and LGDS. **T**

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT

The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals;
e. Incremental Operation and Maintenance; and
f. Property Taxes

GLT PROGRAM FACTORS

After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in the Company's most recent general rate case. **T** **T** **T**

A filing to update the projected program costs will be submitted annually. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the current year. At the same time, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective for services rendered on and after the first day of the following month after the effective date of such change. **T** **T** **T** **T** **T**

RATES

The charges for the respective gas service schedules are:

	Distribution Projects ($/delivery point)	Transmission Projects ($/Ccf)	
			T/N
RGS – Residential Gas Service	$ 0.84	$0.00067	**R/N**
VFD – Volunteer Fire Department Service	0.84	0.00067	**R/N**
CGS – Commercial Gas Service	4.26	0.00051	**R/N**
IGS – Industrial Gas Service	48.86	0.00020	**R/N**
AAGS – As-Available Gas Service	48.86	0.00020	**R/N**
SGSS – Substitute Gas Sales Service	4.26	0.00051	**N**
DGGS – Distributed Generation Gas Service	48.86	0.00020	**I/N**
FT – Firm Transportation Service	N/A	0.00003	**N**
LGDS – Local Gas Delivery Service	N/A	0.00003	**N**

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State Regulation and Rates
Louisville, Kentucky

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APPLICABLE TO

All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.40675
Gas Cost Actual Adjustment (GCAA)	0.00259
Gas Cost Balance Adjustment (GCBA)	(0.00088)
Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:	
None	
Performance-Based Rate Recovery Component (PBRRC)	0.00296
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.41142

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Adjustment Clause **GSC**

Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information:

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.

2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."

2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.

3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Substitute Gas Sales Service Rate SGSS, and Firm Transportation Rate FT. **T**

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) of monthly gas consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process (“approved programs”). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCR for such rate class. **T**

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

DRLS = DSM REVENUE FROM LOST SALES (continued)

1. For each upcoming twelve-month period, the estimated reduction in customer usage (in Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Charge billings for the customer classes. **T**

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE.
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

DSMI = DSM INCENTIVE (continued)

The DSM incentive amount shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT.
The DBA shall be calculated on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest to be calculated at a rate equal to the average of the “Three-Month Commercial Paper Rate” for the immediately preceding twelve-month period. The balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DCCR = DSM CAPITAL COST RECOVERY

The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

$$DCCR = [(RB)\ (ROR + (ROR - DR)\ (TR / (1 - TR))] + OE$$

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

PROGRAMMATIC CUSTOMER CHARGES (continued)

Customer Education and Public Information
This program help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the CGS, IGS, AAGS, SGSS, and FT Standard Gas Rate Schedules. T

Customer Education and Public Information
This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Gas Service Rate RGS and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.01788 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00079 per Ccf
DSM Incentive (DSMI)	$ 0.00083 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf
DSM Balance Adjustment (DBA)	$ (0.00866) per Ccf
Total DSMRC for Rates RGS and VFD	$ 0.01084 per Ccf

Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS*, Substitute Gas Sales Service Rate SGSS*, and Firm Transportation Service Rate FT*	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00086 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf	
DSM Incentive (DSMI)	$ 0.00000 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf	
DSM Balance Adjustment (DBA)	$ (0.00029) per Ccf	
Total DSMRC for Rates CGS, AAGS, and FT	$ 0.00057 per Ccf	

* This charge does not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

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State Regulation and Rates
Louisville, Kentucky

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Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

APPLICABLE
To all gas sold.

RATE MECHANISM
The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$\mathbf{PBRRC = \frac{CSPBR + BA}{ES}}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$\mathbf{CSPBR = TPBRR \times ACSP}$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$\mathbf{TPBRR = (GAIF + TIF + OSSIF)}$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

The BGC shall include the benchmark component as follows:

BGC = TABMGCC

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm seasonal entitlements by pipeline and by zone for which indices are posted. The seasonal percentages represent the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company may have firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

$$SAI = [I(1) + I(2) + I(3)] / 3$$

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, Gulf Coast, Onshore as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for Louisiana - Onshore South, Texas Gas, Zone SL averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas, Zone SL.

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, North as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for East Texas - North Louisiana Area, Texas Gas, zone 1 averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas, Zone 1.

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Appalachia, Lebanon Hub.

I(2) is the *Platts Gas Daily* midpoint postings for Appalachia – Lebanon Hub averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast, Lebanon Hub.

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Texas, Gulf Coast, Onshore Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for South – Corpus Christi, Tennessee, Zone 0 averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee, Texas, Zone 0.

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, Gulf Coast, Onshore as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for Louisiana – Onshore South, Tennessee, 500 Leg averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee, Louisiana, 500 leg.

DAI (TGT-4) and (TGPL-2)

DAI is the Delivery Area Index to be established for **PEFDCQ** made by Company on the day(s) when Company has arranged for deliveries to Company's city gate that are in excess of its total firm pipeline quantity entitlements.

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DATE EFFECTIVE: November 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The daily DAI applicable to the daily purchases made for city-gate delivery shall be the higher of the following, either

DAI = DAI (TGT-1) / (1 – FR%) + CCS + DDCS

or

DAI = DAI (TGT-4) / (1 – FR%) + CCS + DDCS

Where:

DAI (TGT-1) represents the highest daily midpoint posting by *Platts Gas Daily* for East Texas – North Louisiana Area, Texas Gas, zone 1.

DAI (TGT-4) represents the highest daily midpoint posting by *Platts Gas Daily* for Appalachia – Lebanon Hub.

FR% is the tariffed Fuel Retention Percentage under Texas Gas Transmission, LLC's Rate NNS.

CCS are the tariffed NNS Commodity Charge and Surcharges under Texas Gas Transmission, LLC's Rate NNS.

DDCS are the tariffed Daily Demand Charge and Surcharges under Texas Gas Transmission, LLC's Rate NNS.

If an index ceases to exist or fails to report, the Company may use a suitable replacement index and report that change in writing to the Commission in the applicable quarterly report. If the Company elects not to select a replacement index, the average is adjusted accordingly.

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs (excluding any supply reservation fees) plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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State Regulation and Rates
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To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission, LLC.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company, LLC.

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF = Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off-System Sales **(NR)**.

Net Revenue is calculated as follows:

NR = OSREV - OOPC

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm transportation contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\mathbf{PTAGSC} = \frac{\mathbf{TPBRR}}{\mathbf{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\mathbf{TAGSC = AGC + TAAGTC}$$

If the absolute value of the PTAGSC is less than or equal to 3.0%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 3.0%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 3.0% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 3.0% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

Adjustment Clause **WNA**
Weather Normalization Adjustment Clause T

APPLICABLE

The sales to Residential Customers, Volunteer Fire Departments, and Commercial Customers under Rate Schedules RGS, VFD, and CGS shall be increased or decreased monthly by an amount hereinafter described as the WNA.

DETERMINATION OF WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the applicable Distribution Charges for Customers served under Rate Schedules RGS, VFD and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

WNA will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable Distribution Charge T
as set forth on the RGS, VFD, and CGS Rate Schedules. T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE

The utility gross receipts license tax authorized under state law.

Adjustment Clause **HEA**
Home Energy Assistance

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per month. **T**

BILLING
The HEA charge shall be shown as a separate item on customer bills.

PURPOSE
Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service, unless any rate or rider under which you take service explicitly states otherwise. **T**
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS T

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions to the extent that such Terms and Conditions are T not in conflict, nor inconsistent, with the specific provisions in each rate schedule and which shall T constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR

The United Nations Convention on Contracts for the International Sale of Goods is specifically disclaimed and excluded and will not apply to or govern agreements between customers and Company.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which gas service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

General

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied gas service.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render gas service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

Applications for gas service are not transferable and new occupants of premises will be required to make application for service before commencing the use of gas. Customers who have been receiving gas service shall notify Company when discontinuance of service is desired, and shall pay for all gas service furnished until such notice has been given and final meter readings made by Company.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which Customer desires to receive service.

Company will, at any time, upon request, advise any Customer as to the most advantageous rate for existing or anticipated service requirements as defined by the Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, the Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customers will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER'S EQUIPMENT AND INSTALLATION.
Customer shall furnish, install, and maintain at Customer's expense the necessary Customer's Service Line extending from Company's Service Connection at the property line to the building or place of utilization of the gas.

All piping, appliances, and other gas equipment and apparatus, except the meter, regulator, and any gas riser or service line the Company has installed, repaired, or replaced, located on and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof.

OWNER'S CONSENT TO OCCUPY
Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT
Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of gas service or for the purpose of turning on and shutting off the gas supply when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY
Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED
Gas service shall not be used for purposes other than as set forth in customer's application or contract.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. In the event that such Customer desires to continue to receive natural gas service from **T**
Company and/or declines to allow Company to remove Company's facilities hitherto used to provide **T**
natural gas service to Customer, then Customer shall be obligated to take service under Rate SGSS. **T**

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of gas, occasioned by such gas or said pipes and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution mains, Customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and across such intervening property of Customer's piping and facilities required for the supply of gas service to Customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

COMPANY-OWNED SERVICE LINES

The Company will install, own, operate and maintain the service line at the premises of residential and commercial customers, if such premises are not connected to a Company main by a service line. With respect to residential and commercial customers that occupy premises already connected to a Company main by a service line that the Company has installed, repaired, or replaced, the Company shall be responsible for operating and maintaining the customer service line and when the Company determines that replacement of such customer service line is necessary the Company shall be responsible for installing the service line and shall thereafter own the service line.

Any customer accepting gas service under this section shall be deemed to have granted the Company an easement across his property for such service. No service line shall be installed across private property other than the premises of the building to be supplied with gas, except after special investigation and approval by the Company.

When the length of the service pipe required between the property line and the meter is 100 feet or less, the Company will assess no charge for the service pipe installation.

When the length of required service pipe exceeds 100 feet, the Company may require the applicant to contribute toward the cost of the service line installation an amount equal to the estimated cost per foot for each lineal foot of service beyond 100 feet. Contributions by customers toward the Company’s cost of furnishing and installing service lines in accordance with this section are non-refundable.

In the event that the Company is required to undertake any excavation on a customer’s property in connection with the installation, repair, maintenance or replacement of a service line, the Company shall make reasonable efforts to restore the property to its original condition pursuant to generally accepted utility standards for such construction operations.

TERMS AND CONDITIONS

Company Responsibilities

METERING

The gas used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. Company has the right to install any meter or meters it deems in its sole discretion to be necessary or prudent to serve any customer, including without limitation a digital, automated meter reading, automated metering infrastructure, or advanced metering systems meter or meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company. **T T T T**

POINT OF DELIVERY OF GAS

The point of delivery of gas supplied by Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulating equipment.

If the Service Line is owned by the Customer, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of Company’s Service Connection into Customer’s Service Line, irrespective of the location of the metering and regulation equipment.

If the Service Line is owned by the Company, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the outlet of the meter to the Customer’s yard line or house piping.

COMPANY'S EQUIPMENT AND INSTALLATION

The Company shall furnish, install, and maintain at its expense the necessary service connection. The location of this service connection will be made at the discretion and judgment of the Company.

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage or tamper with the same. Customer shall execute a reasonable form of easement agreement, if requested by Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Company Responsibilities

COMPANY'S EQUIPMENT AND INSTALLATION (continued)

Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective gas requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of gas service delivered at Company's property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer's premises or resulting from defects in or accidents to any of Customer's piping, equipment, apparatus or appliances, or resulting from any cause whatsoever other than the negligence of Company.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the gas service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

OBLIGATION TO SERVE

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any

TERMS AND CONDITIONS

Company Responsibilities

Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

SPECIAL RULES FOR CUSTOMERS SERVED FROM HIGH PRESSURE MAINS, GAS TRANSMISSION MAINS, AND STORAGE GATHERING LINES

In order to ensure the integrity, safe operations, and reliability of the Company's gas system, these special rules apply to customers served from high pressure mains, gas transmission mains, and storage gathering lines.

When a customer requests service from a high pressure main, gas transmission main, or storage gathering line under Rate RGS, VFD, CGS, IGS, AAGS, SGSS, or FT, Company shall determine, in its sole discretion, if service is justified, feasible, and consistent with good operating practice. **T**

Upon approval by Company of a request by a customer (or group of customers) for service from a high pressure main, gas transmission main, or storage gathering line, then Company may charge the customer (or group of customers) in addition to the charges under the applicable rate schedule, the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

In no case, shall Company be obligated to provide service to customers served under Rate DGGS from a high pressure main, gas transmission main, or storage gathering line.

PURCHASE OF CERTAIN CUSTOMER-OWNED GAS SERVICE ENTRANCES AND RISERS.

LG&E will reimburse its gas customers who have replaced their service entrances or gas risers (or both) between January 1, 2011 and December 31, 2012. Customers must notify LG&E if they desire such reimbursement. LG&E has no obligation to seek out such customers. LG&E will post on its website a notice of the availability of this reimbursement. The reimbursement will be in the amount of the customers' reasonable costs of replacing such service entrances or gas risers (or both), which must be demonstrated to LG&E's reasonable satisfaction. Customers disputing the amount of reimbursement may contact the Commission. LG&E will reimburse only owners of affected properties, each of whom must have owned the affected property at the time of the replacement of the service entrance or gas riser.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot. All gas received into the system of Company from interstate pipelines shall meet the applicable quality standards of the respective interstate pipeline delivering natural gas to Company All gas received into the system of Company from sources other than an interstate pipeline shall meet the quality standards prescribed in Local Gas Delivery Service Rate LGDS. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

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STANDARD PRESSURE AND MEASUREMENT BASE

The standard distribution pressure of the gas supplied by Company is four ounces per square inch above atmospheric pressure.

Atmospheric pressure shall be assumed in all cases to be 14.5 pounds per square inch and temperature shall be assumed to be 60 degrees Fahrenheit; provided, however, Company reserves the right for billing purposes to correct as necessary the actual temperature to a 60 degree Fahrenheit basis in the case of large volume customers.

All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

DELIVERY PRESSURE

Company shall not be obligated to provide gas service to any Customer at a minimum delivery pressure greater than 50 psig or the expected minimum pipeline pressure, whichever is less.

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS

As used in the entirety of this Tariff, "meter reading" and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a "meter reading." T

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customers meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's electric or gas meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. However, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of rendition thereof. If full payment is not received by the due date of the bill, a late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which

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TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS (continued)

the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill. T T

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two or more meters will not be combined except where Company's operating convenience requires the installation of two or more meters upon Customer's premises instead of one meter.

CUSTOMER RATE MIGRATION

Unless otherwise specified in the applicable rate schedule or rider, a change from one rate to another will be effective with the first full billing period following a customer's request for such change or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual Customer consumption, Company will monitor the usage of each Customer at least once quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Billing

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company’s billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company’s billing.

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 8 except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service
3) Company may offer residential customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first six (6) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the requirements set forth in Section 3 of the Special Terms and Conditions **T** contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.7), Standard Rate Rider PS-FT (Sheet **T** No. 61.2), and the CREDITWORTHINESS section of Rate LGDS (Sheet No. 36.11). **T**

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $100.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d). For combination gas and electric customers, the total deposit will be $260.00.
3) Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Deposits

RESIDENTIAL (continued)

4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d).
2) For customers not meeting the parameters of GENERAL ¶ 2, Company may retain Customer’s deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during the customer’s budget year. If actual usage indicates the customer’s account will not be current with the final payment in the customer’s budget year, the customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer’s next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the Plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed **4/14/16** for Account # **3000-4444-4444**

AMOUNT DUE	DUE DATE
$80.31	**5/8/16**

Account Name: JOHN SMITH
Service Address: 100 Kensington Place Ln
PLEASUREVILLE KY

Online Payments: lge-ku.com
Telephone Payments: 502-589-1444, press 1-2-3
24 hours a day; $2.25 fee
Customer Service: 502-589-1444
M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway
Louisville, KY 40202
M-F, 8am-5pm ET

Next read will occur 5/11/16 - 5/13/16 (Meter Read Portion 08)

BILLING SUMMARY

Previous Balance	261.00
Payment(s) Received	-261.00
Balance as of 4/13/16	**$0.00**
Current Gas Charges	79.52
Current Taxes and Fees	0.79
Total Current Charges as of 4/13/16	**$80.31**
Total Amount Due	**$80.31**

CURRENT USAGE

GAS

Meter Reading Information	**Meter # 563885**
Actual (R) ccf Reading on 4/13/16	8734
Previous (R) ccf Reading on 3/14/16	8657
Current ccf Usage	77
Meter Multiplier	1
Metered ccf Usage	**77**

CURRENT CHARGES

GAS	**Rate:** Residential Gas Service
Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 77 ccf)	20.34
Gas Supply Component ($0.49951 x 77 ccf)	38.46
Weather Normalization Adjustment ($0.26419 x 12.964 ccf)	3.43
Gas DSM ($0.01311 x 77 ccf)	1.01
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$79.52**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By **5/8/16**	**$80.31**
After Due Date, Pay This Amount:	**$82.74**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-4444-4444**
Service Address: 100 Kensington Place Ln

#926190004 2#

JOHN SMITH
100 KENSINGTON PLACE LN
PLEASUREVILLE, KY 40057-1000

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

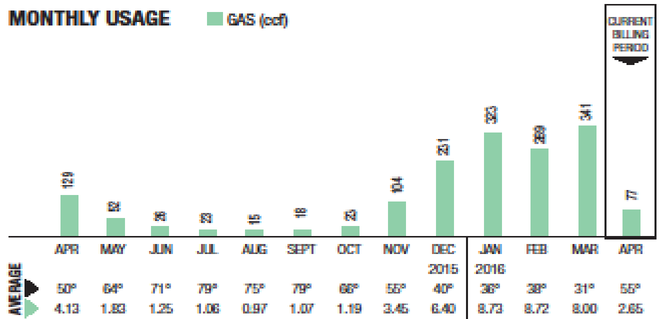
ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS
Bill Format

Page 2 Account # 3000-4444-4444

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**56°**	**52°**
Number of Days Billed	30	28
Avg. Gas Charges per Day	**$2.85**	**$4.13**
Avg. Gas Usage per Day (ccf)	2.57	4.61



TAXES & FEES

Franchise Fee-Pleasureville	0.79
Total Taxes and Fees	**$0.79**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $2.43

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS
Bill Format

a PPL company

Mailed **4/8/16** for Account # **3000-5555-5555**

AMOUNT DUE	DUE DATE
$107.65	5/1/16

Account Name: JOHN SMITH
Service Address: 100 Cassidy Ln, LOUISVILLE KY

BILLING SUMMARY

Previous Balance	185.14
Payment(s) Received	-185.14
Balance as of 4/7/16	**$0.00**
Current Electric Charges	54.03
Current Gas Charges	53.62
Total Current Charges as of 4/7/16	**$107.65**
Total Amount Due	**$107.65**

Online Payments: lge-ku.com
Telephone Payments: 502-589-1444, press 1-2-3
24 hours a day; $2.25 fee
Customer Service: 502-589-1444
M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway
Louisville, KY 40202
M-F, 8am-5pm ET

Next read will occur 5/4/16 - 5/6/16 (Meter Read Portion 03)

CURRENT USAGE

ELECTRIC

Meter Reading Information	**Meter # 700000**
Actual (R) kWh Reading on 4/7/16	58526
Previous (R) kWh Reading on 3/9/16	58072
Current kWh Usage	454
Meter Multiplier	1
Metered kWh Usage	**454**

GAS

Meter Reading Information	**Meter # 600000**
Actual (R) ccf Reading on 4/7/16	2704
Previous (R) ccf Reading on 3/9/16	2658
Current ccf Usage	46
Meter Multiplier	1
Metered ccf Usage	**46**

CURRENT CHARGES

ELECTRIC	**Rate:** Residential Electric Service
Basic Service Charge	10.75
Energy Charge ($0.08076 x 454 kWh)	36.67
Electric DSM ($0.00520 x 454 kWh)	2.36
Electric Fuel Adjustment ($0.00224 x 454 kWh)	1.02
Environmental Surcharge (5.860% x $50.80)	2.98
Home Energy Assistance Fund Charge	0.25
Total Charges	**$54.03**

GAS	**Rate:** Residential Gas Service
Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 46 ccf)	12.15
Gas Supply Component ($0.49951 x 46 ccf)	22.98
Weather Normalization Adjustment ($0.26419 x 6.093 ccf)	1.61
Gas DSM ($0.01311 x 46 ccf)	0.60
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$53.62**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By **5/1/16**	**$107.65**
After Due Date, Pay This Amount:	**$110.91**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-5555-5555**
Service Address: 100 Cassidy Ln

#926190005 1#

JOHN SMITH
100 CASSIDY LN
LOUISVILLE, KY 40229-1000

a PPL company
PO Box 9001960
Louisville, KY 40290-1960

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

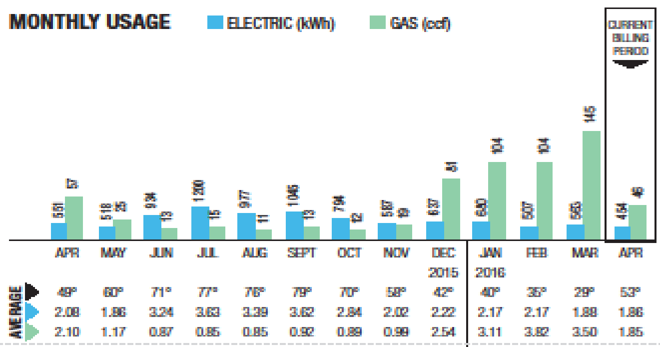
Louisville Gas and Electric Company

TERMS AND CONDITIONS
Bill Format

Page 2 Account # 3000-5555-5555

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	53°	49°
Number of Days Billed	29	29
Avg. Electric Charges per Day	$1.86	$2.08
Avg. Gas Charges per Day	$1.85	$2.10
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.26

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse, or to discontinue, service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least 10 days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

B. When a dangerous condition is found to exist on Customer's or Applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or Applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given 15 days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for **T**
service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a **T**

TERMS AND CONDITIONS

Discontinuance of Service

lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications. **T**

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of the customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered, and assessment of the charges under the Unauthorized Reconnect Charge provision of Special Charges incurred by reason of the fraudulent use. **T** **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Discontinuance of Service

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

TERMS AND CONDITIONS

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
   a) The existing main is of sufficient capacity to properly supply the additional customer(s);
   b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
   c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

3. Where funds were advanced in accordance with paragraph 2 for extensions into developed residential neighborhoods and notwithstanding paragraph 1, any customer that subsequently connects to the main during a ten-year period from the effective date of the main extension contract shall advance to Company a pro rata share of the cost of the extension over 100 feet per connected customer.

4. For each new year-round customer connected to an extension in accordance with paragraph 3, Company will refund to the previous applicant(s) who advanced funds an amount equal to the difference between the refundable amount advanced and the amount of the advance so determined for the new applicant.

5. Company will extend its gas mains to serve a proposed real estate subdivision provided the applicant for such extension advances to Company an amount equal to the estimated cost of the total extension. Company shall have the right to determine the length of the extension and to specify the pipe size and the location of the extension, as well as the timing of its construction.

6. For each new year-round customer actually connected to the extension within a ten-year period following the effective date of the gas main extension contract, but not to extensions or laterals therefrom, Company will refund to applicant(s) who advanced funds in accordance with paragraph 5 above an amount equal to 100 times the average unit cost per foot of extension advanced by such applicant(s); provided that such refunds shall not exceed, in the aggregate, the amount originally advanced to Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Gas Main Extension Rules

7. Company will install at its own expense a service pipe of suitable capacity extending from its gas main to the customer's property line beyond which point all necessary piping shall be installed by and at the expense of the customer and in a manner acceptable to Company.

8. Company will install at its own expense the necessary meter together with the regulator required to convert from medium pressure to service pressure. When a high pressure gas line is tapped to serve a customer or group of customers, Company may charge the customer or customers for the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

9. In the event Company is required to make a further extension of its mains to serve a customer, Company reserves the right to tap any extension constructed under these rules and to make connections from such additional extensions without application of the refunds referred to in paragraph 4 or 6 above.

10. The title to all extensions herein provided for, together with all necessary rights-of-way, permits and easements, shall be and remain in Company.

11. Company shall not be obligated to make service connections or to extend its gas mains in cases where such extensions or connections, in the sole judgment of Company would be infeasible, impractical, or contrary to good operating practice, or where such extensions are not in accordance with the terms of the applicable rate schedule.

TERMS AND CONDITIONS

Gas Service Restrictions

By Order dated September 5, 1973, in Case Nos. 5829 and 5839, the Public Service Commission of Kentucky authorized Company to incorporate in its gas tariff restrictions on the supply of gas service, occasioned by the inadequacy of gas supplies to meet customer demands. These restrictions have been modified from time to time by tariff filings authorized or approved by the Commission. Uncertainty as to future gas supply makes it necessary that Company continue to exercise control over the addition of gas loads to its system, as set forth in these rules.

1. **GENERAL**. Except as specifically provided in these rules, Company will not (a) initiate service to any new customer, location, or service point; (b) permit any commercial customer (including any governmental agency or institution) or any industrial customer to increase its connected load or to expand its gas requirements in any manner; or (c) permit any customer to change to another rate schedule for the purpose of obtaining a higher priority under Company's Tariff.

2. **NEW CUSTOMERS**. Until further notice, Company will accept applications for gas service to new customers as set forth below. Main extensions will be made in accordance with the Gas Main Extension Rules contained in this Tariff.

   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, SGSS, and FT**. Single family dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers. **T**

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, SGSS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied. **T**

3. **INCREASE IN SERVICE TO EXISTING CUSTOMERS**. Until further notice, Company will, upon application, permit increases in the connected gas load or the gas usage of commercial and industrial customers existing as of the effective date of these rules, as follows:

   (a) **ADDITIONAL SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, SGSS, and FT.** **T**
   Company will permit the addition of connected gas loads under Rates RGS, VFD, CGS, DGGS, IGS, SGSS, and FT. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers. **T**

TERMS AND CONDITIONS

Gas Service Restrictions

(b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, SGSS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied. **T**

4. **LOAD ADDITIONS TO BE AGGREGATED**. Limitations on new or additional gas loads as specified herein refer to the aggregate of loads added subsequent to the effective date of these rules, and not to individual increments made from time to time.

5. **VOLUMES OF GAS USAGE**. Daily and monthly volumes of gas usage may be established or increased to reflect additions of connected load or increased usage of connected load existing as of the effective date of these rules. For customers subject to curtailment under Company's Curtailment Rules, Monthly Base Period Volumes will be established or adjusted accordingly.

6. **TRANSFERS BETWEEN LOCATIONS**. Company may permit any customer to transfer his own gas entitlement from one location to another; provided, however, that transfers of service cannot be aggregated so as to exceed the limitations on connected load set forth in Paragraphs 2 and 3 above with respect to Rates RGS, VFD, CGS, DGGS, IGS, SGSS, and FT. **T**

7. **PRIORITY CONSIDERATIONS**. If at any time, Company is required to select among applicants for service as provided for in Paragraphs 2(b) or 3(b) above, it will, to the extent practicable, observe the following priorities in the order named:

   (a) Schools, hospitals and similar institutions.
   (b) Other commercial establishments.
   (c) Industrial process and feedstock uses.
   (d) Other industrial applications.

8. **LAPSE OF APPLICATIONS**. If any applicant for new or increased service under these rules is not ready to take such service within twelve (12) months from the date of application, such application shall be void. Any reapplication shall be subject to Company's rules in effect at the time thereof.

9. Applicants may make application for gas service beyond that provided for in these rules, to be initiated at such time as these rules may be terminated or modified so as to enable Company to provide the service applied for. Company will file such applications in the order of receipt and dispose of them as circumstances dictate.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

1. **DEFINITIONS** (for purposes of these Rules).

COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

HUMAN NEEDS: Residential and other customers whose facilities are used for residential dwellings on either a permanent or temporary basis or a facility providing critical emergency services (including, but not limited to, apartment buildings, correctional institutions, hospitals, nursing homes, assisted living facilities, hotels, motels, fire department stations, police stations, national guard facilities, and emergency response agency facilities).

INDUSTRIAL CUSTOMERS: Customers engaged primarily in a process or processes which create or change raw or unfinished materials into another form or product, including, but not limited to, the generation of electric power as further described in Rate IGS and Rate DGGS.

SMALL INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes is 10,000 Mcf or less.

LARGE INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes exceeds 10,000 Mcf.

PILOT LIGHT REQUIREMENTS: Gas used on either a continuous or intermittent basis only for the ignition of the fuel in the main burner; does not include any gas used to preheat or atomize solid or liquid fuels.

BASE PERIOD: The twelve (12) months ending on the October 31 preceding the calendar year which is the subject of the implementation of any curtailments hereunder.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Curtailment Rules

MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption (including sales and transportation volumes) during the Base Period.

AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month.

Some customers may have usage falling within more than one (1) of the above categories; as such, these customers may be required to segregate their total usage accordingly.

2. **COMBINATION OF AUTHORIZED MONTHLY VOLUMES**. Subject to a written application by a customer and acceptance thereof by Company, Company may permit any customer served through more than one point of delivery at any location, or any person, corporation or entity served with gas at more than one location, to take gas through the points or at the locations of its choosing, provided that the gas so taken will not exceed the combined Authorized Monthly Volumes applicable to such points of delivery, and provided that only volumes purchased under rate schedules subject to Pro-Rata Curtailment may be so combined. Gas taken through each individual point of delivery will be billed at the rate applicable to such point of delivery.

   The right to combine Authorized Monthly Volumes as herein described is limited to individual customers or individual persons, corporations or entities and such right will not extend to similar combinations between or among unrelated customers. Nor shall such combinations be employed by any customer for the purpose of obtaining a lower overall cost of gas.

   Provided, however, in the case of Industrial Customers provided with sales service under Rate IGS or Special Contracts, which have requested and received approval to combine Authorized Monthly Volumes, Monthly Base Period Volumes for such combined Industrial Customers must aggregate to not less than 10,000 Mcf for a twelve-month period and such combination shall be treated as a Large Industrial Customer for the purpose of implementing either Pro-Rata or Emergency Curtailment.

   For the purpose of assessment of penalties, the point of delivery will be considered on a combined basis, so that the actual combined takes will be measured against combined Authorized Monthly Volumes. It will be the responsibility of any applicant for this treatment to advise Company in writing as to the party or entity to be held accountable for the payment of such penalty.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Curtailment Rules

3. **PRO-RATA CURTAILMENT**. In order to meet seasonal and daily sendout requirements, to preserve underground storage deliverability, and to provide for adequate and timely underground storage injections, Company will implement pro-rata curtailment with respect to the classes of customers here listed:

    (a) All customers served under Rate AAGS.
    (b) Large Industrial Customers provided with sales service under Rate IGS, Rate SGSS, or Special Contracts. **T**

    Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

    Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts.

    During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT**. In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

    (1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

    (2) Issue Action Alerts to Pool Managers under Rider PS-TS-2 serving customers under Rider TS-2, and take similar actions applicable to transportation customers served under Special Contracts. Customers of Pool Managers that fail to comply with Action Alerts may be required to terminate service under Rider PS-TS-2 and Rider TS-2 and return to firm sales service.

TERMS AND CONDITIONS

Curtailment Rules

(3) Discontinue service to customers served under Rate AAGS.

(4) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS, Rate SGSS, or Special Contracts for gas sales service. **T**

(5) Once curtailment in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers.

(6) Company may request that transportation customers served under Rate FT and Special Contracts allow Company's use of customer-owned gas to supply higher priority end-use customers. Company shall negotiate compensation for such gas with any customer that complies with such request.

(7) Once curtailment of customers in level 5 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers.

(8) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network.

5. **PENALTY CHARGES**. Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment.

Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service.

TERMS AND CONDITIONS

Curtailment Rules

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service.

The payment of penalty charges for takes of gas in excess of Authorized Monthly Volumes or authorized quantities shall not be considered as giving any customer the right to make unauthorized takes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to Company.

Company shall return to all customers through Company’s Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company’s supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

Special Contracts
Gas

Summary of Proposed Charges Under Gas Special Contracts

Intra-Company Sales

	Sales Rate:	
	Customer Charge:	$750.00 per month
	Monthly Demand Charge:	$10.8978 per Mcf
	Distribution Charge :	$0.2992 per Mcf Delivered
	Gas Supply Cost Component:	Per Rate IGS

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(4)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing: (a) The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or (b) A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

See attached present and proposed tariffs in comparative form on the same sheet side-by-side. Please note that on each sheet of the side-by-side comparison the present tariff is on the left and the proposed tariff is on the right.

P.S.C. Electric No. 10
Canceling P.S.C. Electric No.9

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In the nine counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

P.S.C. Electric No. 11
Canceling P.S.C. Electric No.10

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In the nine counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Second Revision of Original Sheet No. 1
Canceling P.S.C. Electric No. 10, First Revision of Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Third Revision of Original Sheet No. 1.1
Canceling P.S.C. Electric No. 10, Second Revision of Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 9, 2016

DATE EFFECTIVE: November 4, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 5
Canceling P.S.C. No. 10, Original Sheet No. 5

Standard Rate **RS**
Residential Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase secondary delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge of:	$ 0.08639 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 5

Standard Rate **RS**
Residential Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase secondary delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff.

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.04790	$0.03681	$0.08471	**R**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
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The Basic Service Charge shall be the minimum charge.

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Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

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If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision to Original Sheet No. 6
Canceling P.S.C. No. 10, Original Sheet No. 6

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Energy shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Energy and RTOD-Demand combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule GS (where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge:	
Off Peak Hours:	$0.06128 per kWh
On Peak Hours:	$0.23263 per kWh

<u>ADJUSTMENT CLAUSES</u>
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 6

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Energy shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Energy and RTOD-Demand combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule GS (where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge per month:	$22.00	**T/I**
Plus an Energy Charge per kWh:		**T**
Off-Peak Hours:	$0.05850	**T/R**
On-Peak Hours:	$0.23263	**T**

ADJUSTMENT CLAUSES **T**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak	
			T
Weekdays	11 AM - 7 AM	7 AM - 11 AM	
Weekends	All Hours		

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 7
Canceling P.S.C. No. 10, Original Sheet No. 7

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Demand shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Demand and RTOD-Energy combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule GS (where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge:	$ 0.04565 per kWh
Plus a Demand Charge:	
Off Peak Hours:	$ 3.25 per kW
On Peak Hours:	$12.38 per kW

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 7

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Demand shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Demand and RTOD-Energy combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule GS (where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
   a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
   b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge per month:	$22.00	**T/I**
Plus an Energy Charge per kWh:	$ 0.03681	**T/R**
Plus a Demand Charge per kW:		**T**
Base Hours:	$ 3.51	**T/I**
Peak Hours:	$ 7.68	**T/R**

ADJUSTMENT CLAUSES **T**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 7.1

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

DETERMINATION OF PRICING PERIODS
Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 7.1

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

DETERMINATION OF PRICING PERIODS
Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October

	Base	Peak	
			T
Weekdays	All Hours	1 PM - 5 PM	**T**
Weekends	All Hours		

All Other Months of November continuously through March

	Base	Peak	
			T
Weekdays	All Hours	7 AM - 11 AM	**T**
Weekends	All Hours		

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate will not be eligible for Company's Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 9
Canceling P.S.C. No. 10, Original Sheet No. 9

Standard Rate **VFD**
Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief,
2) having at least one firefighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge of:	$ 0.08639 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 9

Standard Rate **VFD**
Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief; **T**
2) having at least one firefighting apparatus; and **T**
3) half the members must be volunteers.

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.04790	$0.03681	$0.08471	**R**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 10
Canceling P.S.C. No. 10, Original Sheet No. 10

Standard Rate **GS**
General Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. Electric No. 6, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

Basic Service Charge:	$25.00 per month for single-phase service $40.00 per month for three-phase service
Plus an Energy Charge of:	$ 0.09650 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
If Company determines based on Customer's usage history that Customer may be exceeding the maximum load permitted under Rate GS, Company may, at its discretion, equip Customer with a meter capable of measuring demand to determine Customer's continuing eligibility for Rate GS. If Customer is equipped with a demand-measuring meter, Customer's load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE
The Basic Service Charge shall be the Minimum Charge.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 10

Standard Rate **GS**
General Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. Electric No. 6, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

Basic Service Charge per month:	$31.50 single-phase service			**T/I**
	$50.40 three-phase service			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.06509	$0.03721	$0.10230	**I**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF LOAD **T**
Service hereunder will be metered except when, by mutual agreement of Company and Customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 10.1

Standard Rate **GS**

General Service Rate

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 10.1

Standard Rate **GS**

General Service Rate

DETERMINATION OF MAXIMUM LOAD **T**

If Company determines based on Customer's usage history that Customer may be exceeding the maximum load permitted under Rate GS, Company may, at its discretion, equip Customer with a meter capable of measuring demand to determine Customer's continuing eligibility for Rate GS. If Customer is equipped with a demand-measuring meter, Customer's load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE

The Basic Service Charge shall be the Minimum Charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 15
Canceling P.S.C. No. 10, Original Sheet No. 15

Standard Rate **PS**
Power Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

	Secondary	Primary
Basic Service Charge per month:	$90.00	$200.00
Plus an Energy Charge per kWh of:	$ 0.04071	$ 0.03925
Plus a Demand Charge per kW of:		
Summer Rate:		
(Five Billing Periods of May through September)	$18.40	$ 15.92
Winter Rate:		
(All other months)	$15.99	$ 13.63

Where the monthly billing demand is the greater of:
a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 15

Standard Rate **PS**
Power Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE	Secondary	Primary	
Basic Service Charge per month:	$90.00	$240.00	**I**
Plus an Energy Charge per kWh:	$ 0.04071	$ 0.03925	**T**
Plus a Demand Charge per kW:			**T**
Summer Rate:			
(Five Billing Periods of May through September)	$20.93	$18.64	**I**
Winter Rate:			
(All other months)	$18.19	$15.96	**I**

Where the monthly billing demand is the greater of:
a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) if applicable, a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 15.1

Standard Rate **PS**
Power Service Rate

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in Percent)}}$$

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month’s charges.

TERM OF CONTRACT
Contracts under this rate shall be for an initial term of one (1) year, remaining in effect from month to month thereafter until terminated by notice of either party to the other.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 15.1

Standard Rate **PS**
Power Service Rate

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in Percent)}}$$

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month’s charges.

TERM OF CONTRACT
Contracts under this rate shall be for an initial term of one (1) year, remaining in effect from month to month thereafter until terminated by notice of either party to the other.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 20
Canceling P.S.C. No. 10, Original Sheet No. 20

Standard Rate **TODS**
Time-of-Day Secondary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for secondary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum loads exceed 250 kW and whose 12-month-average monthly maximum loads do not exceed 5,000 kW.

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh of:	$ 0.04049
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 6.74
Intermediate Demand Period	$ 5.10
Base Demand Period	$ 4.60

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 20

Standard Rate **TODS**
Time-of-Day Secondary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for secondary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum loads exceed 250 kW and whose 12-month-average monthly maximum loads do not exceed 5,000 kW.

RATE

Basic Service Charge per month:	$200.00	**T**
Plus an Energy Charge per kWh:	$ 0.04049	**T**
Plus a Maximum Load Charge per kW:		**T**
Peak Demand Period:	$ 7.56	**T/I**
Intermediate Demand Period:	$ 5.54	**T/I**
Base Demand Period:	$ 4.84	**T/I**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 20.1

Standard Rate **TODS**
Time-of-Day Secondary Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 20.1

Standard Rate **TODS**
Time-of-Day Secondary Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

Standard Rate **TODS**
Time-of-Day Secondary Service

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

Standard Rate **TODS**
Time-of-Day Secondary Service

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 22
Canceling P.S.C. No. 10, Original Sheet No. 22

Standard Rate **TODP**
Time-of-Day Primary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03824
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.26
Intermediate Demand Period	$ 3.91
Base Demand Period	$ 3.75

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 22

Standard Rate **TODP**
Time-of-Day Primary Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$330.00	**I**
Plus an Energy Charge per kWh:	$ 0.03824	**T**
Plus a Maximum Load Charge per kVA:		**T**
Peak Demand Period:	$ 6.86	**T/I**
Intermediate Demand Period:	$ 5.03	**T/I**
Base Demand Period:	$ 3.18	**T/I**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
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Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 22.1

Standard Rate **TODP**
Time-of-Day Primary Service

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT
Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 22.1

Standard Rate **TODP**
Time-of-Day Primary Service

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT
Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 25
Canceling P.S.C. No. 10, Original Sheet No. 25

Standard Rate **RTS**
Retail Transmission Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for transmission service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$1,000.00
Plus an Energy Charge per kWh of:	$ 0.03711
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 4.85
Intermediate Demand Period	$ 3.30
Base Demand Period	$ 3.05

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 25

Standard Rate **RTS**
Retail Transmission Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for transmission service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$1,400.00	**I**
Plus an Energy Charge per kWh:	$ 0.03711	**T**
Plus a Maximum Load Charge per kVA:		**T**
Peak Demand Period:	$ 6.98	**T/I**
Intermediate Demand Period:	$ 5.12	**T/I**
Base Demand Period:	$ 1.52	**T/I**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 25.1

Standard Rate **RTS**
Retail Transmission Service

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT
Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 25.1

Standard Rate **RTS**
Retail Transmission Service

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
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DUE DATE OF BILL
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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 30
Canceling P.S.C. No. 10, Original Sheet No. 30

Standard Rate **FLS**
Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service FLS schedule of Kentucky Utilities Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission
Basic Service Charge per month:	$1,000.00	$1,000.00
Plus an Energy Charge per kWh of:	$ 0.03612	$ 0.03612
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 3.42	$ 3.42
Intermediate Demand Period	$ 2.37	$ 2.37
Base Demand Period	$ 2.37	$ 1.62

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 30

Standard Rate **FLS**
Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service FLS schedule of Kentucky Utilities Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$ 330.00	$1,400.00	**R/I**
Plus an Energy Charge per kWh:	$ 0.03824	$ 0.03711	**T/I**
Plus a Maximum Load Charge per kVA:			**T**
Peak Demand Period:	$ 6.30	$ 6.41	**T/I**
Intermediate Demand Period:	$ 4.48	$ 4.56	**T/I**
Base Demand Period:	$ 2.83	$ 1.35	**T/R**

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and **T**

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or **T**
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. **T**

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30.1

Standard Rate **FLS**
Fluctuating Load Service

ADJUSTMENT CLAUSES
The amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 30.1

Standard Rate **FLS**
Fluctuating Load Service

ADJUSTMENT CLAUSES
The amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD
The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS
The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30.2

Standard Rate **FLS**
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA

Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours,

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 30.2

Standard Rate **FLS**
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA

Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours,

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30.3

Standard Rate **FLS**
Fluctuating Load Service

if any, under the CURTAILABLE SERVICE RIDER CSR. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System ("LKE System") owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of LG&E and KU. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 30.3

Standard Rate **FLS**
Fluctuating Load Service

if any, under the CURTAILABLE SERVICE RIDER CSR. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System ("LKE System") owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of LG&E and KU. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

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Service will be furnished under Company's Terms and Conditions applicable hereto.

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Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 35
Canceling P.S.C. No. 10, Original Sheet No. 35

Standard Rate **LS**
Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is offered under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of street, driveways, yards, lots, and other outdoor areas where secondary voltage of 120/240 is available.

Service will be provided under written contract, signed by customer prior to service commencing, when additional facilities are required.

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities.

OVERHEAD SERVICE
Based on Customer's lighting choice, Company will furnish, own, install, and maintain the lighting unit. A basic overhead service includes lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company will, upon request furnish ornamental poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for basic overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only
High Pressure Sodium				
452	Cobra Head	16,000	0.181	$13.78
453	Cobra Head	28,500	0.294	16.17
454	Cobra Head	50,000*	0.471	18.61
455	Directional	16,000	0.181	$14.73
456	Directional	50,000*	0.471	19.44
457	Open Bottom	9,500	0.117	$11.93
Metal Halide				
470	Directional	12,000	0.150	$13.81
473	Directional	32,000	0.350	19.89
476	Directional	107,800*	1.080	42.04

Should Customer request underground service, Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of Company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the overhead lighting system.

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 35

Standard Rate **LS**
Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is offered under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of street, driveways, yards, lots, and other outdoor areas where secondary voltage of 120/240 is available.

Service will be provided under written contract, signed by customer prior to service commencing, when additional facilities are required.

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities.

OVERHEAD SERVICE
Based on Customer's lighting choice, Company will furnish, own, install, and maintain the lighting unit. A basic overhead service includes lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only). Company will, upon request furnish ornamental poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for basic overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	
High Pressure Sodium					
452	Cobra Head	16,000	0.181	$13.78	
453	Cobra Head	28,500	0.294	16.17	
454	Cobra Head	50,000*	0.471	18.61	
455	Directional	16,000	0.181	$14.73	
456	Directional	50,000*	0.471	19.44	
457	Open Bottom	9,500	0.117	$11.93	
Metal Halide					D
473	Directional	32,000*	0.350	$19.89	T
					D
Light Emitting Diode (LED)					N
490	Cobra Head	8,179	0.080	$14.62	N
491	Cobra Head	14,166	0.134	17.73	N
492	Cobra Head	23,214*	0.228	27.18	N
493	Open Bottom	5,007	0.050	$ 9.65	N
					T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 35.1
Canceling P.S.C. No. 10, Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider. For wood poles installed prior to 3/1/2010, such charge will be in accordance with the rates listed on Sheet No, 36.1 of the Restricted Lighting Service Rate RLS Tariff.

UNDERGROUND SERVICE
Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Decorative Smooth	Monthly Charge: Historic Fluted
High Pressure Sodium					
412	Colonial, 4-Sided	5,800	0.083	$20.82	
413	Colonial, 4-Sided	9,500	0.117	21.56	
444	Colonial, 4-Sided	16,000	0.181	21.69	
415	Acorn	5,800	0.083	$21.21	
416	Acorn	9,500	0.117	23.63	
445	Acorn	16,000	0.181	23.63	
427	London	5,800	0.083		$36.24
429	London	9,500	0.117		37.15
431	Victorian	5,800	0.083		$33.97
433	Victorian	9,500	0.117		36.07
400	Dark Sky	4,000	0.060	$25.33	
401	Dark Sky	9,500	0.117	25.98	
					Westchester/Norfolk
956	Victorian/London Bases				$ 3.56
423	Cobra Head	16,000	0.181	$27.32	
424	Cobra Head	28,500	0.294	29.55	
425	Cobra Head	50,000*	0.471	35.27	

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

OVERHEAD SERVICE (continued) T
Should Customer request underground service, Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of Company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the overhead lighting system.

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider. For wood poles installed prior to 3/1/2010, such charge will be in accordance with the rates listed on Sheet No. 36.1 of the Restricted Lighting Service Rate RLS Tariff. T

UNDERGROUND SERVICE
Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Decorative Smooth	Monthly Charge: Historic Fluted	
High Pressure Sodium						
412	Colonial, 4-Sided	5,800	0.083	$22.30		I
413	Colonial, 4-Sided	9,500	0.117	22.85		
444	Colonial, 4-Sided	16,000	0.181	24.06		
415	Acorn	5,800	0.083	$24.47		
416	Acorn	9,500	0.117	24.42		
445	Acorn	16,000	0.181	25.64		
427	London	5,800	0.083		$36.76	I
429	London	9,500	0.117		37.15	
431	Victorian	5,800	0.083		$36.40	I
433	Victorian	9,500	0.117		36.72	I
400	Dark Sky	4,000	0.060	$25.33		
401	Dark Sky	9,500	0.117	25.98		
					Westchester/Norfolk	
956	Victorian/London Bases				$ 4.63	I T

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 35.2
Canceling P.S.C. No. 10, Original Sheet No. 35.2

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Decorative Smooth
High Pressure Sodium					
439/420	Contemporary	16,000	0.181	$17.42	$30.86
440/421	Contemporary	28,500*	0.294	19.37	33.96
441/422	Contemporary	50,000*	0.471	23.55	39.63
Metal Halide					
479/480	Contemporary	12,000	0.150	$15.08	$24.85
481/482	Contemporary	32,000	0.350	21.67	31.43
483/484	Contemporary	107,800*	1.080	45.01	54.76

Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the conventional overhead lighting system.

Where Customer's location would require the installation of additional facilities, Company may furnish, own, and maintain the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill. Billing for this service to be made a part of bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION
The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 16, 2015

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 35.2

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued)
RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Decorative Smooth	
High Pressure Sodium (continued)						T
423	Cobra Head	16,000	0.181		$35.52	T/I
424	Cobra Head	28,500	0.294		38.42	T/I
425	Cobra Head	50,000*	0.471		45.85	T/I
439/420	Contemporary	16,000	0.181	$17.42	37.57	I
440/421	Contemporary	28,500*	0.294	19.37	40.07	I
441/422	Contemporary	50,000*	0.471	23.55	43.12	I
Metal Halide						D
481/482	Contemporary	32,000*	0.350	$21.67	$40.61	T/I
						D
Light Emitting Diode (LED)						N
496	Cobra Head	8,179	0.080		$53.90	
497	Cobra Head	14,166	0.134		57.01	
498	Cobra Head	23,214*	0.228		66.46	
499	Colonial, 4-Sided	5,665	0.068		$46.45	

Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the conventional overhead lighting system.

Where Customer's location would require the installation of additional facilities, Company may furnish, own, and maintain the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill. Billing for this service to be made a part of bill rendered for other electric service.

DETERMINATION OF ENERGY CONSUMPTION
The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff. T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer.

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement lighting within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

ADJUSTMENT CLAUSES T

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer.

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement lighting within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 36
Canceling P.S.C. No. 10, Original Sheet No. 36

Standard Rate **RLS**
Restricted Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole

OVERHEAD SERVICE
Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only).

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Fixture & Wood Pole	Fixture & Orn. Pole
Mercury Vapor						
252	Cobra/Open Bottom	8,000	0.210	$10.25		
203	Cobra Head	13,000	0.298	11.69		
204	Cobra Head	25,000	0.462	14.41		
209	Cobra Head	60,000	1.180	29.46		
207	Directional	25,000	0.462	$16.44		
210	Directional	60,000	1.180	30.66		
201	Open Bottom	4,000	0.100	$ 8.77		
Metal Halide						
471	Directional	12,000	0.150		$16.09	N/A
474/475	Directional	32,000	0.350		22.18	29.64
477	Directional	107,800	1.080		45.23	N/A

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 36

Standard Rate **RLS**
Restricted Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS. Spot replacements will not be available for Mercury Vapor and Incandescent rate codes. T T

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole. T

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities. T T

OVERHEAD SERVICE
Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only).

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Fixture & Wood Pole	Fixture & Orn. Pole	
Mercury Vapor							
252	Cobra/Open Bottom	8,000	0.210	$10.56			I
203	Cobra Head	13,000	0.298	12.04			I
204	Cobra Head	25,000	0.462	14.84			I
209	Cobra Head	60,000*	1.180	30.34			T/I
207	Directional	25,000	0.462	$16.93			I
210	Directional	60,000*	1.180	31.58			T/I
201	Open Bottom	4,000	0.100	$ 9.03			I
Metal Halide							
470/471	Directional	12,000	0.150	$13.81	$16.56		N/I
474/475	Directional	32,000*	0.350		22.18	$29.64	T
476/477	Directional	107,800*	1.080	42.04	45.23		N

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 36.1
Canceling P.S.C. No. 10, Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE

Rate Code		Monthly Charge
Wood Pole		
958	Installed Before 3/1/2010	$11.32
900	Installed Before 7/1/2004	2.06

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 200 feet of conductor per fixture on appropriate poles.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Decorative Smooth
High Pressure Sodium					
275	Cobra/Contemporary	16,000	0.181		$25.86
266	Cobra/Contemporary	28,500	0.294		28.44
267	Cobra Contemporary	50,000	0.471		32.64
276	Coach/Acorn	5,800	0.083		$15.20
274	Coach/Acorn	9,500	0.117		18.26
277	Coach/Acorn	16,000	0.181		23.11
279/278	Contemporary	120,000	1.000	$45.11	$76.24
417	Acorn, Bronze	9,500	0.117		$24.75
419	Acorn, Bronze	16,000	0.180		26.30
280	Victorian	5,800	0.083	$20.41	
281	Victorian	9,500	0.117	21.42	
282	London	5,800	0.083	$20.56	
283	London	9,500	0.117	21.89	

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE

Rate Code		Monthly Charge	
Wood Pole			
958	Installed Before 3/1/2010	$11.32	
900	Installed Before 7/1/2004	2.68	I

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 200 feet of conductor per fixture on appropriate poles.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Decorative Smooth	
High Pressure Sodium						
275	Cobra/Contemporary	16,000	0.181		$33.62	I
266	Cobra/Contemporary	28,500	0.294		36.97	I
267	Cobra Contemporary	50,000*	0.471		42.43	T/I
276	Coach/Acorn	5,800	0.083		$19.76	I
274	Coach/Acorn	9,500	0.117		22.85	I
277	Coach/Acorn	16,000	0.181		24.06	I
279/278	Contemporary	120,000*	1.000	$45.11	$76.24	T
417	Acorn, Bronze	9,500	0.117		$25.33	I
419	Acorn, Bronze	16,000	0.180		26.48	I
280	Victorian	5,800	0.083	$26.53		I
281	Victorian	9,500	0.117	27.85		I
282	London	5,800	0.083	$26.73		I
283	London	9,500	0.117	28.46		I

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 36.2
Canceling P.S.C. No. 10, Original Sheet No. 36.2

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth
High Pressure Sodium					
426	London	5,800	0.083		$34.26
428	London	9,500	0.117		35.17
430	Victorian	5,800	0.083		33.30
432	Victorian	9,500	0.117		35.41
Victorian/London Bases					
950	Old Town				$ 3.47
951	Chesapeake				3.73
Poles					
901	10" Smooth Pole				10.82
902	10" Fluted Pole				12.91
Mercury Vapor					
318	Cobra Head	8,000	0.210		$18.09
314	Cobra Head	13,000	0.298		19.93
315	Cobra Head	25,000	0.462		23.85
347	Cobra (State of KY Pole)	25,000	0.462	$23.84	
206	Coach	4,000	0.100		$13.08
208	Coach	8,000	0.210		14.91
Incandescent					
349	Continental Jr.	1,500	0.102		$ 9.57
348	Continental Jr.	6,000	0.447		13.93

Where Customer's location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

DUE DATE OF BILL

Payment is due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill. Billing for this service to be made a part of the bill rendered for other electric service.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 36.2

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
High Pressure Sodium (continued)						T
426	London	5,800	0.083		$36.37	I
428	London	9,500	0.117		35.83	I
430	Victorian	5,800	0.083		36.01	I
432	Victorian	9,500	0.117		36.32	I
Victorian/London Bases						
950	Old Town				$ 4.51	I
951	Chesapeake				4.24	I
Poles						
901	10' Smooth Pole				10.82	T
902	10' Fluted Pole				12.91	T
Mercury Vapor						
318	Cobra Head	8,000	0.210		$19.56	I
314	Cobra Head	13,000	0.298		21.54	I
315	Cobra Head	25,000	0.462		25.78	I
						D
206	Coach	4,000	0.100		$14.14	I
208	Coach	8,000	0.210		16.12	I
Metal Halide						N
479/480	Contemporary	12,000	0.150	$17.18	$32.31	N
483/484	Contemporary	107,800*	1.080	45.01	58.35	N
Incandescent						
349	Continental Jr.	1,500	0.102		$ 9.57	
348	Continental Jr.	6,000	0.447		13.93	

Where Customer's location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 36.3

Standard Rate **RLS**
Restricted Lighting Service

DETERMINATION OF ENERGY CONSUMPTION
The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT
For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 36.3

Standard Rate **RLS**
Restricted Lighting Service

DUE DATE OF BILL T
Payment is due within sixteen (16) business days (no less than twenty-two (22) calendar days) T
from the date of the bill. Billing for this service to be made a part of the bill rendered for other T
electric service. T

DETERMINATION OF ENERGY CONSUMPTION
The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT
For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 37
Canceling P.S.C. No. 10, Original Sheet No. 37

Standard Rate **LE**
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE
$0.06934 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

CONDITIONS OF DELIVERY
1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

2. The location of the point of delivery of the energy supplied hereunder and the voltage at which such delivery is effected shall be mutually agreed upon by Company and the customer in consideration of the type and size of customer's street lighting system and the voltage which Company has available for delivery.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 37

Standard Rate **LE**
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE
$0.06934 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

CONDITIONS OF DELIVERY
1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

2. The location of the point of delivery of the energy supplied hereunder and the voltage at which such delivery is effected shall be mutually agreed upon by Company and the customer in consideration of the type and size of customer's street lighting system and the voltage which Company has available for delivery.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. No. 10, First Revision of Original Sheet No. 38
Canceling P.S.C. No. 10, Original Sheet No. 38

Standard Rate **TE**
Traffic Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

RATE

Basic Service Charge:	$4.00 per delivery per month
Plus an Energy Charge of:	$0.07871 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00222 dated December 7, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 38

Standard Rate **TE**
Traffic Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, but not limited to, signals, cameras, or **T**
other traffic lights, electronic communication devices, and emergency sirens. **T**

RATE

Basic Service Charge per month:	$4.00 per delivery point	**T**
Plus an Energy Charge per kWh:	$0.08533	**T/I**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE

1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.

3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE

1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.

3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40

Standard Rate — **CTAC**

Cable Television Attachment Charges

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Where Company is willing to permit the attachments of cables, wires and appliances to its poles where, in Company's judgment, such attachments will not interfere with its electric service requirements and other prior licensees using Company's poles. Attachments will be permitted upon execution by both parties of a Cable Television Attachment Agreement supplied by Company.

ATTACHMENT CHARGE

$7.25 per year for each attachment to pole.

BILLING

Attachment Charges to be billed semi-annually based on the number of pole attachments being maintained on December 1 and June 1. Provided, however, that should the Agreement be terminated in accordance with the terms of the said Agreement, the Attachment Charges will be prorated to the date of such termination. Payment will be due within thirty (30) days from date of bill. Non-payment of bills shall constitute a default of the Agreement.

TERM OF AGREEMENT

The Cable Television Attachment Agreement shall become effective upon execution by both parties and shall continue in effect for not less than one (1) year, subject to provisions contained in the agreement. At any time thereafter, the Customer may terminate the agreement by giving not less than six (6) months' prior written notice. Upon termination of the agreement, Customer shall immediately remove its cables, wire, appliances and all other attachments from all poles of Company.

TERMS AND CONDITIONS OF POLE ATTACHMENTS

Pole attachments shall be permitted in accordance with this Schedule. Company's Terms and Conditions shall be applicable, to the extent they are not in conflict with or inconsistent with, the special provisions of this Schedule.

Upon written Agreement, Company is willing to permit, to the extent it may lawfully do so, the attachment of cables, wires and appliances to its poles by a cable television system operator, hereinafter "Customer," where, in its judgment, such use will not interfere with its electric service requirements and other prior licensees using Company's poles, including consideration of economy and safety, in accordance with this schedule approved by the Public Service Commission. The Terms and Conditions applicable to such service are as follows:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40

Standard Rate — **PSA** — T

Pole and Structure Attachment Charges

APPLICABLE

In all territory served.

AVAILABILITY

Available to the facilities of cable television system operators and telecommunications carriers as provided below except: (1) facilities of incumbent local exchange carriers with joint use agreements with the Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. Nothing in this tariff expands the right to attach to the Company's structures beyond the rights otherwise conveyed by law.

APPLICABILITY OF SCHEDULE TO CURRENT LICENSE AGREEMENTS

Any telecommunication carrier that executed a license agreement permitting attachments to the Company's structures prior to the effective date of this Schedule shall be subject to the rates, terms, and conditions of this Schedule upon expiration or termination of its license agreement.

DEFINITIONS

"Affiliate" means, with respect to an entity, any entity controlling, controlled by, or under common control with such entity.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means the Cable or Wireless Facilities and all associated appliances including without limitation any overlashed cable, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or otherwise conflicts with Company's electric design and construction standards.

"Attachment Customer" means a customer that attaches its facilities to one or more of the Company's Structures and has executed an Attachment Customer Agreement with the Company.

"Attachment Customer Agreement" means the written agreement provided by the Company and executed between Attachment Customer and Company incorporating the terms and conditions of this Schedule.

"Cable" means the fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Cable television system operator" means a Person who operates a system that transmits television signals, for distribution to subscribers of its services for a fee, by means of wires or cables connecting its distribution facilities with its subscriber's television receiver or other equipment connecting to the subscriber's television receiver, and not by transmission of television signals through the air, and subscription to the system's service is available to the public.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.1

Standard Rate **CTAC**
Cable Television Attachment Charges

1. **ATTACHMENT APPLICATIONS AND PERMITS**
   Before making attachment to any pole or poles of Company, Customer shall make application and receive a permit therefore on a form to be supplied by Company. The information submitted by Customer with the application for a permit shall consist of drawings and associated descriptive matter which shall be adequate in all detail to enable Company to thoroughly check the proposed installation of Customer. Before the attachments are made, the permit must be approved by Company. Customer shall not build separate pole lines along existing facilities of Company and shall not place intermediate poles in spans of Company, unless authorized by Company in writing. Company shall have the right to remove unauthorized Customer attachments at Customer's expense after notice to Customer. In the event a pole attachment count does not correspond to the recorded attachment count, Customer will pay a back attachment fee for any excess attachments. The back attachment fee will be double the rate otherwise in effect over the time since last pole attachment count and shall be payable on demand.

2. **PERMITTED ATTACHMENTS**
   Customer shall be permitted to make only one bolt attachment for one messenger on tangent poles and two bolt attachments for two messengers on corner poles. A maximum of five individual coaxial cables may be supported by any single messenger if these cables are all attached to the messenger by suitable lashings or bindings, and so that the maximum overall dimension of the resulting cable bundle does not exceed two (2) inches. Any messenger attachment other than to tangent poles must be properly braced with guys and anchors provided by Customer to the satisfaction of Company. The use of existing Company anchors for this purpose must be specifically authorized in writing, subject to additional charge, and will not ordinarily be permitted. The use of crossarms or brackets shall not be permitted. In addition to messenger attachments, Customer will be permitted one Customer amplifier installation per pole and four service drops to be tapped on cable messenger strand and not on pole. Customer power supply installations shall be permitted, but only at pole locations specifically approved by Company. Any or all of the above are considered one attachment for billing purposes. Any additional attachments desired by Customer will be considered on an individual basis by Company, and as a separate attachment application.

3. **CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS**
   Customer's cables, wires and appliances, in each and every location, shall be erected and maintained in accordance with the requirements and specifications of the National Electrical Safety Code, current edition, and Company's construction practices, or any amendments or revisions of said Code and in compliance with any rules or orders now in effect or that hereinafter may be issued by the Public Service Commission of Kentucky, or other authority having jurisdiction. In the event any of Customer's construction does not meet any of the foregoing requirements, Customer will correct same in fifteen work days after written notification. Company may make corrections and bill Customer for total costs incurred, if not corrected by Customer.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.1

Standard Rate **PSA**
Pole and Structure Attachment Charges T

"Communication Space" means the area below the Communication Worker Safety Zone to the limit of allowable NESC clearance, department of transportation or other governmental requirements, and Company's internal construction standards on poles.

"Communication Worker Safety Zone" means the space between the facilities located in the Supply Space and facilities located in the Communications Space on poles.

"Contractor" means any Person employed or engaged by Attachment Customer to perform work or render services upon or in the immediate vicinity of Company's Structures or associated facilities other than Attachment Customer and Attachment Customer's employees.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69 kV, but does not include a non-wood street light pole or a wood street light pole that is not located in a public right-of-way.

"Duct" means a pipe, tube, conduit, manhole, or other structure made for supporting and protecting electric and/or communications wires or cables and in which wires, cables and conduits may be placed for support or protection but excluding (1) any pipe now or previously used for the transmission or distribution of natural gas, (2) any duct system supporting electric supply lines operated at 69kV or greater, and (3) any vault.

"High Volume Application" means an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes submitted to Company within a 30-day period.

"Macro Cell Facility" means a wireless communications system site that is typically high-power and high-site, and capable of covering a large physical area, as distinguished from a distributed antenna system (DAS), small cell, or WiFi attachment, by way of example. Macro Cell Facilities are typically, but not exclusively, co-located on Transmission Poles and communications monopoles and towers.

"Make Ready Survey" means a survey, in the form prescribed by the Company from time to time, prepared by the Company or an Approved Contractor describing in reasonable detail the make-ready engineering requirements, and such other information as the Company may require, for the installation of an Attachment or group of Attachments on a Structure or group of Structures.

"NEC" means the National Electrical Code.

"NESC" means the National Electrical Safety Code.

"Person" is defined by KRS 278.010(2).

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.2

Standard Rate **CTAC**

Cable Television Attachment Charges

4. **MAINTENANCE OF ATTACHMENTS**
Customer shall, at its own expense, make and maintain said attachments in safe condition and in thorough repair, and in a manner suitable to Company and so as not to conflict with the use of said poles by Company, or by other parties, firms, corporations, governmental units, etc., using said poles, pursuant to any license or permit by Company, or interfere with the working use of facilities thereon or which may, from time to time, be placed thereon. Customer shall promptly at any time, at its own expense, upon written notice from Company, relocate, replace or renew its facilities placed on said poles, and transfer them to substituted poles, or perform any other work in connection with said facilities that may be required by Company but in no case longer than 30 day after date of written request. In cases of emergency, however, Company may arrange to relocate, replace or renew the facilities placed on said poles by Customer, transfer them to substituted poles or perform any other work in connection with said facilities that may be required in the maintenance, replacement, removal or relocation of said poles, the facilities thereon or which may be placed thereon, or for the service needs of Company, or its other licensees, and Customer shall, on demand, reimburse Company for the expense thereby incurred.

5. **COSTS ASSOCIATED WITH ATTACHMENTS**
In the event that any pole or poles of Company to which Customer desires to make attachments are inadequate to support the additional facilities in accordance with the aforesaid specifications, Company will indicate on the application and permit form the changes necessary to provide adequate poles and the estimated cost thereof to Customer. If Customer still desires to make the attachments, Company will replace such inadequate poles with suitable poles and Customer will, on demand, reimburse Company for the total cost of pole replacement necessary to accommodate Customer attachments, less the salvage value of any pole that is removed, and the expense of transferring Company's facilities from the old to the new poles. Where Customer desired attachments can be accommodated on present poles of Company by rearranging Company's facilities thereon, Customer will compensate Company for the full expense incurred in completing such rearrangements, within ten days after receipt of Company's invoice for such expense. Customer will also, on demand, reimburse the owner or owners of other facilities attached to said poles for any expense incurred by it or them in transferring or rearranging said facilities. In the event Customer makes an unauthorized attachment which necessitates rearrangements when discovered, then Customer shall pay on demand twice the expense incurred in completing such rearrangements.

6. **MAINTENANCE AND OPERATION OF COMPANY'S FACILITIES**
Company reserves to itself, its successors and assigns, the right to maintain its poles and to operate its facilities thereon in such manner as will, in its own judgment, best enable it to fulfill its electric service requirements, but in accordance with the specifications herein before referred to. Company shall not be liable to Customer for any interruption to service to Customer's subscribers or for interference with the operation of the cables, wires and appliances of Customer arising in any manner out of the use of Company's poles hereunder.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.2

Standard Rate **PSA** **T**

Pole and Structure Attachment Charges

"Service Drop" means a Cable, attached to a pole with a J-hook or other similar hardware that connects the trunk line to an Attachment Customer's premises.

"Structure" means any Company pole, conduit, duct, or other facility normally used by the Company to support or protect its electric conductors but shall not include (1) any Transmission Pole other than Transmission Poles to which the Company has attached its own electric supply lines operated at less than 69kV; (2) any street light pole that is not a wood pole located in a public right-of-way; or (3) any pole that the Company has leased to a third party.

"Supply Space" means the space above the Communications Worker Safety Zone used for the installation of electric supply lines.

"Telecommunications carrier" means a Person who operates a system that (1) transmits by wire or wireless means, between or among points specified by the user, information of the user's choosing without change in the form or content of the information as sent or received, and (2) provides such transmission services for a fee directly to or for the public, or to such classes of users as to be effectively available directly to or for the public, and includes, but is not limited to, internet service providers, voice over internet protocol service providers, cellular and mobile phone service providers or resellers of such services.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69 kV or greater.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Attachment Customer's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with the Company's electric design and construction standards.

ATTACHMENT CHARGES
$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$ 84.00 per year for each Wireless Facility.

BILLING
All attachment charges for use of Structures will be billed semi-annually based upon the type and number of Attachment Customer's Attachments reflected in Company's records on December 1 and June 1. A bill issued under this Schedule shall be due upon its issuance. Any bill not paid in full within 60 days of its issuance shall be assessed a late payment fee of 3 percent on the bill's current charges. If the Attachment Customer fails to pay all charges and fees billed within six months of the bill's issuance, the Company may remove any or all of Attachment Customer's

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.3

Standard Rate **CTAC**
Cable Television Attachment Charges

7. **FRANCHISES AND EASEMENTS**
Customer shall submit to Company evidence, satisfactory to Company, of Customer's authority to erect and maintain Customer's facilities within public streets, highways and other thoroughfares within the above described territory which is to be served and shall secure any necessary consent by way of franchise or other satisfactory license, permit or authority, acceptable to Company from State, County or municipal authorities or from the owners of property where necessary to construct and maintain facilities at the locations of poles of Company which it desires to use. Customer must secure its own easement rights on private property. Customer must, regardless of authority received or franchises given by governmental agencies, conform to all requirements of Terms and Conditions with regard to Company's property. Company's approval of attachments shall not constitute any representation or warranty by Company to Customer regarding Customer's right to occupy or use any public or private right-of-way.

8. **INSPECTION OF FACILITIES**
Company reserves the right to inspect each new installation of Customer on its poles and in the vicinity of its lines or appliances and to make periodic inspections, every two (2) years or more often as plant conditions warrant of the entire plant of Customer. Such inspections, made or not, shall not operate to relieve Customer of any responsibility, obligation or liability.

9. **PRECAUTIONS TO AVOID FACILITY DAMAGE**
Customer shall exercise precautions to avoid damage to facilities of Company and of others supported on said poles; and shall assume all responsibility of any and all loss for such damage caused by it. Customer shall make an immediate report to Company of the occurrence of any damage and shall reimburse Company for the expense incurred in making repairs.

10. **INDEMNITIES AND INSURANCE**
Customer shall defend, indemnify and save harmless Company from any and all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature-including but not limited to costs and expenses of defending against the same and payment of any settlement or judgment therefore, by reason of (a) injuries or deaths to persons, (b) damages to or destructions of properties, (c) pollutions, contaminations of or other adverse effects on the environment or (d) violations of governmental laws, regulations or orders whether suffered directly by Company itself or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from acts or omissions of Customer, its employees, agents, or other representatives or from their presence on the premises of Company, either solely or in concurrence with any alleged joint negligence of Company.

Customer shall provide and maintain in an Insurance Company(s) authorized to do business in the Commonwealth of Kentucky, the following:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.3

Standard Rate **PSA**
Pole and Structure Attachment Charges T

Attachments. In lieu of or in addition to removal of Attachments, the Company may exercise any other remedies available under law to address Attachment Customer's failure to make timely payment of any charges assessed under this Schedule.

TERM OF SERVICE
An executed Attachment Customer Agreement shall be for a term of 10 years and shall thereafter automatically renew for successive one year periods unless Company or Attachment Customer provides the other with written notice of termination at least 60 days prior to the renewal date.

TERMS AND CONDITIONS OF ATTACHMENT
Attachments to Company's Structures that do not interfere with the Company's electric service requirements and the Attachments of existing customers and joint users shall be permitted in accordance with the terms and conditions of this Schedule. The Terms and Conditions set forth in Section 5 of this Tariff shall also be applicable to the extent they are not in conflict with or inconsistent with this Schedule's provisions.

1. **ATTACHMENT CUSTOMER AGREEMENT**
No Attachments shall be made to Company's Structures until Attachment Customer has executed an Attachment Customer Agreement. The Attachment Customer Agreement shall incorporate the terms and conditions set forth in this Schedule.

2. **NO PROPERTY RIGHTS**
No use, however extended, of Company Structures shall create or vest in the Attachment Customer any right, title or interest in the Structures. Attachment Customer Agreement confers only a non-exclusive right to affix and install Attachments to and on Company's Structures. The Company is not required to maintain any Structure for a period longer than demanded by its electric service requirements.

3. **USE OF COMPANY'S FACILITIES BY OTHERS**
Nothing in this Schedule shall affect the rights or privileges previously conferred by the Company to others. The rights granted under this Schedule and the Attachment Customer Agreement shall at all times be subject to such previously conferred privileges and shall not affect the rights or privileges that may be conferred by the Company in the future to others.

4. **TRANSFER OF RIGHTS**
Except as provided in this Schedule, Attachment Customer's rights under the Attachment Customer Agreement are non-delegable, non-transferable and non-assignable. Any delegation, transfer or assignment of any interest created by the Attachment Customer Agreement or this Schedule without Company's prior written consent is voidable at the Company's option.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.4

Standard Rate **CTAC**
Cable Television Attachment Charges

(a) Insurance protection for Customer employees to the extent required by the Workmen's Compensation Law of Kentucky and, where same is not applicable or if necessary to provide a defense for Company, Employer's Liability Protection (covering both Company and Customer) for Customer employees for no less than $100,000.00 per employee.

(b) Public Liability and Business Liability insurance with a minimum limit of $500,000.00 for each person injured and with a minimum total limit of $1,000,000.00 for each accident and a minimum limit of $100,000.00 for property damage for each accident.

(c) Public Liability and Property Damage insurance on all automotive equipment used by Customer on job to the extent of the amounts for Public Liability and Property Damage insurance set out in the preceding Paragraph (b).

(d) In the event that work covered by the Agreement includes work to be done in places or areas where the Maritime Laws are in effect, then and in that event additional insurance protection to the limits in Paragraph (b) above for liability arising out of said Maritime Laws.

e) In the event the work covers fixed wing aircraft, rotor lift, lighter than air aircraft or any other form of aircraft, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b).

(f) In the event the work covers blasting, explosives or operations underground, in trenches or other excavations, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b), together with products hazard and completed operations insurance where applicable, affording protection to the limits above prescribed. Customer's liability insurance shall be written to eliminate XCU exclusions. Said insurance is to be kept in force for not less than one year after cancellation of the Agreement.

Before starting work, Customer shall furnish to Company a certificate(s) of insurance satisfactory to Company, evidencing the existence of the insurance required by the above provisions, and this insurance may not be canceled for any cause without sixty (60) days advance written notice being first given Company; provided, that failure of Company to require Customer to furnish any such certificate(s) shall not constitute a waiver by Company of Customer's obligation to maintain insurance as provided herein.

Each policy required hereunder shall contain a contractual endorsement written as follows: "The insurance provided herein shall also be for the benefit of Louisville Gas and Electric Company so as to guarantee, within the policy limits, the performance by the named insured of the indemnity provisions of the Cable Television Attachment Agreement between the named insured and Louisville Gas and Electric Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Louisville Gas and Electric Company."

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.4

Standard Rate **PSA**
Pole and Structure Attachment Charges T

Attachment Customer shall not permit a third party to overlash or utilize any Attachment without Company's prior written consent. Company may condition its consent upon such third party's compliance with all provisions of the Attachment Customer Agreement, this Schedule, and such other terms as Company may reasonably require.

5. COMPANY'S ABANDONMENT OF STRUCTURE
The Company shall provide an Attachment Customer with a minimum of 180 days' notice before abandoning a Structure to which the Attachment Customer has made an Attachment unless state or local law, easement provisions, or contractual obligations to a third party requires the Structure to be abandoned in a shorter period, in which case the Company shall provide as much notice as is reasonably practicable.

6. FRANCHISES AND EASEMENTS
Attachment Customer shall secure at its own expense any right-of-way, easement, license, franchise or permit from any Person that may be required for the construction or maintenance of Attachments by or for the Attachment Customer. If requested by Company, Attachment Customer shall submit to Company satisfactory evidence of such right-of-way, easement, license, franchise or permit. Company's approval of Attachments shall not constitute any representation or warranty regarding Attachment Customer's right to occupy or use any public or private right-of-way.

Upon an Attachment Customer's written request, the Company may provide to the Attachment Customer such non-private information as the Company may have regarding the name of the record landowners from which the Company obtained easements for Structures. Such information is provided without representation or warranty as to its accuracy or completeness. The Company has no obligation to correct or supplement any information so provided. If the Company provides assistance to the Attachment Customer in obtaining easements or other property rights, the Attachment Customer shall reimburse the Company's cost of providing such assistance within 30 days of its receipt of an invoice from Company.

Attachment Customer shall indemnify and save harmless Company from all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Attachment Customer to secure any right of way, easement, license, franchise or permit.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.5

Standard Rate **CTAC**
Cable Television Attachment Charges

11. ATTACHMENT REMOVAL AND NOTICES
Customer may at any time voluntarily remove its attachments from any pole or poles of Company, but shall immediately give Company written notice of such removal on a form to be supplied by Company. No refund of any attachment charge will be due on account of such voluntary removal.

12. FORBIDDEN USE OF POLES
Prior to Customer's initial attachment, Company reserves the right due to engineering design requirements to refuse use by Customer of certain or specific poles or structures (such as normal transmission routes). Upon notice from Company to Customer that the use of any pole or poles is forbidden by municipal or other public authorities or by property owners, the permit covering the use of such pole or poles shall immediately terminate and Customer shall remove its facilities from the affected pole or poles at once. No refund of any attachment charge will be due on account of any removal resulting from such forbidden use.

13. NON-COMPLIANCE
If Customer shall fail to comply with any of the provisions of these Rules and Regulations or Terms and Conditions or default in any of its obligations under these Rules and Regulations or Terms and Conditions and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, forthwith terminate the Agreement or the permit covering the poles as to which such default or non- compliance shall have occurred, by giving written notice to Customer of said termination. No refund of any rental will be due on account of such termination.

14. WAIVERS
Failure to enforce or insist upon compliance with any of these Rules and Regulations or Terms and Conditions or the Agreement shall not constitute a general waiver or relinquishment thereof, but the same shall be and remain at all times in full force and effect.

15. USE OF COMPANY'S FACILITIES BY OTHERS
Nothing herein contained shall be construed as affecting the rights or privileges previously conferred by Company, by contract or otherwise, to others, not parties to the Agreement, to use any poles covered by the Agreement; and Company shall have the right to continue and to extend such rights or privileges. The attachment privileges herein granted shall at all times be subject to such existing contracts and arrangements.

16. ASSIGNMENT
Customer shall not assign, transfer or sublet the privileges hereby granted and/or provided in the Agreement without the prior consent in writing of Company.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.5

Standard Rate **PSA**
Pole and Structure Attachment Charges **T**

7. ATTACHMENT APPLICATIONS AND PERMITS

a. Unless waived by the Company, Attachment Customer shall make written application, in the form and manner prescribed by the Company for permission to install Attachments on or in any Structure. Each application shall include: (1) in the case of poles, the owner, number and location of all Structures for which license to attach is sought and the amount of space required thereon; (2) in the case of Ducts, the number of linear feet of Duct space and the specific location of each such Duct to be utilized, the amount of requested space, the nature of any changes or inner Duct or Ducts proposed to be installed and any other construction that might be required by the proposed Attachments; (3) the physical attributes of all proposed Attachments; (4) a load bearing study for each Attachment, unless the Company finds such study is not necessary; (5) the proposed start date for installation of the Attachments; (6) any issues then known to Attachment Customer regarding space, engineering, access or other matters that might require resolution before installation of Attachments; and (7) proposed make ready drawings. Company may request additional information be included with the application at its reasonable discretion. Attachment Customer shall clearly distinguish in its application between Distribution Poles and Transmission Poles for which Attachments are proposed. Any Approved Contractor gathering information for an application to use Ducts must be accompanied by a Company-designated inspector. The Company shall schedule Approved Contractor inspections of Ducts within 15 days of its receipt of a request for such inspection.

b. Attachment Customer shall be responsible for all costs associated with the application, a Make Ready Survey, engineering analysis, and the Company's review of the application. Attachment Customer shall reimburse Company upon presentation of an invoice for such costs. If the Attachment Customer does not request Attachments to a Transmission Pole or Duct, Company shall complete a Make Ready Survey within 60 days of its receipt of Attachment Customer's completed application. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for performance.

c. Upon completion of the Make Ready Survey, the Company shall notify Attachment Customer in writing whether its application for use of Company's Structures has been granted, of any necessary changes to the proposed construction drawings, and the conditions, if any, imposed on the installation or use of Attachments. The Company reserves the right to deny access to any Structure based upon lack of capacity, safety, reliability, engineering standards or other good reason. The Company may deny access to Transmission Poles in its discretion for any reason; provided that such denials shall be determined in a non-discriminatory manner. Transmission Poles that do not support electric supply lines operated at less than 69kV are not available for Attachments under this Schedule.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2016-00371 dated xxxx

17. PROPERTY RIGHTS
No use, however extended, of Company poles under the Agreement shall create or vest in Customer any ownership or property rights in said poles, but Customer shall be and remain a customer only. Nothing herein contained shall be construed to compel Company to maintain any of said poles for a period longer than demanded by its electric service requirements.

18. FAILURE TO PROCEED
Customer agrees to proceed as expeditiously as practical with the work of providing the television cable service to the area described in the Agreement. Within ninety (90) days from the date of the Agreement, Customer shall make progress reasonably satisfactory to Company in the installation of its facilities or shall demonstrate, to the reasonable satisfaction of Company, its ability to proceed expeditiously.

19. TERMINATION
Upon termination of the Agreement in accordance with any of its terms, Customer shall immediately remove its cables, wires and appliances from all poles of Company. If not removed, Company shall have the right to remove them at the cost and expense of Customer.

20. SECURITY
Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).
(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

d. Within 15 days of notifying Attachment Customer of the approval of its application, Company shall provide Attachment Customer a written statement of the costs of any necessary Company make-ready work, including but not limited to rearrangement of electric supply facilities and pole change out. Attachment Customer shall indicate its approval of this statement by submitting payment of the statement amount within 15 days of receipt. If facilities of a third party are required to be rearranged or transferred, Attachment Customer shall coordinate with the third party for such rearrangement or transfer and shall pay the costs related thereto. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for preparation of a written statement of the costs of any necessary Company make-ready work.

e. If an existing Structure is replaced or a new Structure is erected solely to provide adequate capacity for Attachment Customer's proposed Attachments, Attachment Customer shall pay a sum equal to the actual material and labor cost of the new Structure, as well as any replaced appurtenances, plus the cost of removal of the existing Structure minus its salvage value, within 30 days of receipt of an invoice. The new Structure shall be Company's property regardless of any Attachment Customer payments toward its cost. Attachment Customer shall acquire no right, title or interest in or to such Structure.

f. If Company is unable to perform the Make Ready Survey and engineering analysis within the time period established under Section 7b, it shall advise the Attachment Customer and promptly meet with the Attachment Customer to develop a mutually agreeable plan of performance.

g. If Company fails to perform the make-ready work within 60 days of receipt of Attachment Customer's payment of the make-ready costs, Attachment Customer may perform such work at its expense using an Approved Contractor, except that Attachment Customer may not perform such work with respect to Transmission Poles or Ducts. Company shall refund any unexpended make-ready fees within 30 days of notice that Attachment Customer has performed the work. Attachment Customer shall notify Company upon completion of such make-ready work and Company may inspect such work prior to the construction of Attachments. Attachment Customer shall bear the cost of such Company inspection.

h. If Attachment Customer submits to Company within a 30-day period an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes, such application or applications shall be considered a High Volume Application. The provisions set forth in Sections 7b through 7g that relate to time

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Standard Rate **CTAC**
Cable Television Attachment Charges

e) Company in its sole discretion may agree in writing to accept other collateral (such as a cash deposit or an irrevocable bank letter of credit) in substitution for the bond required by, and subject to the other requirements of, this Section 20.

21. NOTICES
Any notice, or request, required by these Rules and Regulations or Terms and Conditions or the Agreement shall be deemed properly given if mailed, postage pre-paid, to Company, in the case of Company; or in the case of the Customer, to its representative designated in the Agreement. The designation of the person to be notified, and/or his address may be changed by Company or Customer at any time, or from time to time, by similar notice.

22. ADJUSTMENTS
Nothing contained herein or in any Agreement shall be construed as affecting in any way the right of Company, and Company shall at all times have the right, to unilaterally file with the Public Service Commission a change in rental charges for attachments to poles, other charges as provided for, any rule, regulation, condition or any other change required. Such change or changes to become effective upon approval of the Commission or applicable regulations or statutes, and shall constitute an amendment to the Agreement.

23. BINDING EFFECT
Subject to the provisions of Section 16 hereof, the Agreement and these Rules and Regulations or Terms and Conditions shall extend to and bind the successors and assigns of the parties hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.7

Standard Rate **PSA** **T**
Pole and Structure Attachment Charges

period and cost-reimbursement of the Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make-ready work, shall not apply to High Volume Applications. The Company and Attachment Customer submitting a High Volume Application shall develop a mutually agreeable plan of performance and cost reimbursement for Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make ready work, shall set this plan to writing and shall file it with the Commission as a special contract.

i. A Service Drop may be affixed and installed on a Distribution Pole without making written application if (1) it is affixed within six (6) inches of Attachment Customer's existing Attachment, (2) it conforms to all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to construction and installation of Attachments, and (3) written notice of each such Service Drop is provided to Company in the month following the month of its installation. A Service Drop shall be counted as an Attachment for purposes of billing and permitting if it (1) is attached to a pole without an existing Attachment, (2) extends more than one span along the trunk line (in which case each individual pole to which such Service Drop is attached shall be treated as the site of an individual Attachment), or (3) is not affixed to a pole within six (6) inches of Attachment Customer's existing Attachment.

8. CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS

a. Attachment Customer shall not construct or install any Attachments until Company has approved in writing the design, construction, and installation practices for Attachment Customer's Attachments.

b. All Attachments shall be constructed and installed in a manner reasonably satisfactory to Company and so as not to interfere with the Company's present or future use of its Structures. Attachments in Ducts shall not include any splice enclosures or excess cable. Attachment Customer shall maintain, operate and construct all Attachments in such manner as to ensure Company's full and free access to all Company facilities. All Attachments shall conform to Company's electric design and construction standards and applicable requirements of the NESC, NEC, and all other applicable codes and laws. In the event of a conflict, the more stringent standard shall apply.

c. Attachment Customer shall identify each of its Attachments with a tag, approved in advance by Company, that includes Attachment Customer's name, 24-hour contact telephone number, and such other information as Company may require. Attachment Customer shall tag new Attachments at the time of construction. Any Attachments existing as of the date of execution of Attachment Customer Agreement shall be tagged within 180 days of the date of the Agreement. All Cable placed by Attachment Customer

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State Regulation and Rates
Louisville, Kentucky

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The proposed LG&E Pole and Structure Attachment Charges Rate PSA (formerly named Rate CTAC) is contained on 20 pages instead of eight pages.

Standard Rate **PSA** T

Pole and Structure Attachment Charges

within a Company-owned or controlled Duct shall be enclosed within Attachment Customer furnished inner-duct and shall be clearly marked and identified as belonging to Attachment Customer at all access points.

d. In the design, installation and maintenance of its Attachments, Attachment Customer shall comply with all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to the work of constructing and installing the Attachments. All work shall be performed in accordance with the applicable standards of the NESC and the NEC, including amendments thereto adopted. Attachment Customer shall take all necessary precautions, by the installation of protective equipment or other means, to protect all Persons and property of all kinds against injury or damage caused by or occurring by reason of the construction, installation or existence of Attachments.

e. Attachment Customer shall immediately report to Company (1) any damage caused to property of Company or others when installing or maintaining Attachments, (2) any Attachment Customer's failure to meet the requirements set forth in this Schedule for assuring the safety of Persons and property and compliance with laws and regulations of public authorities and standard-setting bodies, and (3) any unsafe condition relating to Company's Structures identified by Attachment Customer.

f. Attachment Customer shall complete installation of its Attachments within 60 days of the later of approval of the application for such Attachments or, if make-ready work is required under such approval, completion of make-ready work, and shall notify Company in writing upon its completion. If Attachment Customer fails to complete the installation within this time period, the Company may revoke its permit for the Attachment. Prior to revoking the permit for the Attachment, Company shall provide written notice of the revocation to the Attachment Customer. Company may conduct an inspection of such Attachments. Attachment Customer shall reimburse Company within 30 days of presentation of an invoice for such inspections.

g. Company may monitor Attachment Customer's construction and installation of Attachments. If the need for a monitor is caused by Attachment Customer's failure to comply with the terms of this Schedule, the Attachment Customer Agreement, or any applicable law or regulation, Attachment Customer shall reimburse Company for the actual cost of any such monitoring within 30 days of receipt of an invoice for such cost. For locations where Attachment Customer's construction and installation are within Company underground facilities, Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within 30 days of receipt of an invoice.

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h. Attachment Customer may use qualified contractors of its own choice to perform work below the Communication Worker Safety Zone. For any work in or above the Communication Worker Safety Zone that Company allows Attachment Customer to perform, Attachment Customer shall use an Approved Contractor who may, at Company's discretion, be required to be accompanied by a Company-designated inspector. For any work in Company's Ducts, Attachment Customer shall use an Approved Contractor, who must be accompanied by a Company-designated inspector. The Company shall schedule a Company-designated inspector to accompany an Approved Contractor within 15 days of its receipt of such request for such inspector. The costs of such inspection shall be reimbursed to the Company in the same manner described in Section 8g above.

i. Attachment Customer shall comply with all applicable Federal, State, and local laws, rules and regulations with respect to environmental practices undertaken pursuant to the construction, installation, operation and maintenance of its Attachments. Attachment Customer shall not bring, store or utilize any hazardous materials on any Company site without the Company's prior express written consent. To the extent reasonably practicable, Attachment Customer shall restore any property altered pursuant to its performance under the Attachment Customer Agreement to its condition existing immediately prior to the alteration. Company has no obligation to correct or restore any property altered by Attachment Customer and bears no responsibility for Attachment Customer's compliance with applicable environmental regulations.

j. If Attachment Customer fails to install any Attachment in accordance with the standards and terms set forth in this Schedule and Company provides written notice to Attachment Customer of such failure, Attachment Customer, at its own expense, shall make necessary adjustments within 30 days of receipt of such notice. Subject to Section 15 of this Schedule, if Attachment Customer fails to make such adjustments within such time period, Company may make the repairs or adjustments, and Attachment Customer shall pay Company for the actual cost thereof, plus 50 percent, within 30 days of receipt of an invoice.

k. Attachment Customer is responsible for any damage, fines or penalties resulting from any noncompliance with the construction and maintenance requirements and specifications set forth in this Section 8. Company undertakes no duty to require any specific action by Attachment Customer and assumes no responsibility by requiring such compliance or by requiring Attachment Customer to meet any specifications or to make any corrections, modifications, additions or deletions to any work or planned work by Attachment Customer.

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l. Within 15 days of completion of the installation of the Attachment, Attachment Customer shall furnish Company with complete "as-built" drawings in a computer generated electronic format (or such other format as is agreeable to Company). Hand drawings shall not be submitted.

9. ADDITIONAL REQUIREMENTS FOR WIRELESS FACILITIES

a. Wireless Facilities Attachments may be attached to Distribution Poles only.

b. Company may require Attachment Customer to furnish with any written application for permission to install a Wireless Facilities Attachment a mock-up of the proposed Attachment.

c. Attachment Customer is solely responsible for ensuring that the radiofrequency ("RF") radiation emitted by its Wireless Facilities, alone and/or in combination with any and all sources of RF radiation in the vicinity, is within the limits permitted under all applicable governmental and industry standard safety codes for general population/uncontrolled exposure. Attachment Customer shall install appropriate signage on the poles to which Wireless Facilities have been attached, to warn line workers or the general public of the presence of RF radiation and the need for precautionary measures. Attachment Customer shall periodically inspect the signage and replace the signage if necessary to ensure that the signage, including text and warning symbols, remains clearly visible.

d. Each Wireless Facility installation shall include a switch that operates to disconnect and de-energize the antenna. In non-emergency circumstances, Company employees or contractors will make reasonable efforts to contact Attachment Customer at a telephone number that Attachment Customer has marked on the Wireless Facility installation to request a temporary power shut-down. Company personnel or those of other attaching entities will operate the power disconnect switch to ensure that the antenna is not energized while work on the pole is in progress. In emergency circumstances, Company personnel and those of other entities attached to Company poles may accomplish the power-down by operation of the power disconnect switch without advance notice to Attachment Customer.

e. Attachment Customer is solely responsible for ensuring compliance with all Federal Communication Commission antenna registration requirements, Federal Aviation Administration air hazard requirements, or similar requirements with respect to the location of Attachment Customer's Wireless Facilities on Company's poles.

f. All power supplies, equipment cabinets, meter bases and other equipment associated with the Wireless Facilities that are large enough to impede accessibility shall be installed off-pole, consistent with the applicable standards of the NESC, Company standards, and all applicable laws, rules, regulations, ordinances, and other applicable governmental directives.

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Louisville Gas and Electric Company

10. OVERLASHING OF CABLE

Attachment Customer may overlash Cable to its existing Attachments without such overlashing being considered a separate Attachment subject to an Attachment Charge and without making written application provided: (1) a pole load analysis was performed for such overlashing; (2) such overlashing is completed within 120 days of the Attachment over which the overlashing occurs, (3) no make-ready work of any kind is necessary to accommodate the overlashing; (4) Attachment Customer obtained a permit from the Company for such overlashing; and (5) Attachment Customer provides Company with written notice of such overlashing within 30 days of completion. Any overlashing that fails to meet these conditions shall be deemed a new Attachment for all purposes except the assessment of Attachment Charges. Notwithstanding the foregoing, no bundle of Attachment Customer's Cable shall exceed two inches in diameter.

11. MAINTENANCE OF ATTACHMENTS AND STRUCTURES

Attachment Customer shall maintain Attachments in safe condition and in good repair, in a manner reasonably suitable to Company and so as not to conflict with any use of Company facilities (including Structures) by Company or any other Person using such facilities pursuant to any license or permit by Company. Attachment Customer shall not interfere with the working use of any other Person's property on or in such facilities or any such property, which may be placed on or near the Structures and other facilities.

Company reserves to itself, its successors, Affiliates and assigns, the right to maintain Structures and other Company property and to operate its business and maintain its property in such a manner as will, in its own judgment, best enable it to fulfill its own service requirements. Company shall not be liable to Attachment Customer for any interference with the operation of Attachment Customer's facilities, or loss of business arising in any manner out of the use of Company's Structures or other property.

12. NATIONAL JOINT UTILITIES NOTIFICATION SYSTEM

Within 30 days of executing Attachment Customer Agreement, and prior to making application for any Attachment, Attachment Customer will join National Joint Utilities Notification System ("NJUNS"), a web-based system developed to improve joint use communication, and will actively participate during the Term of Service, by entering field information into the NJUNS system within the times required by the system. Should Attachment Customer fail to actively participate in NJUNS and should such failure cause the Company to incur expense or liability to others, Attachment Customer shall reimburse the Company its expense and indemnify and hold the Company harmless from any damages or liability arising out of such failure. If Company at a later date elects to use a different web-based system for the joint use communication, it shall notify Attachment Customer at least sixty (60) days in advance of such change and Attachment Customer shall join that system.

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State Regulation and Rates
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13. INSPECTIONS
Company may make periodic inspections for the purpose of determining compliance with this Schedule and with the Attachment Customer Agreement. Neither the Company's right to make inspections nor any inspection made by Company shall relieve an Attachment Customer of any responsibility, obligation or liability assumed under this Schedule.

Upon thirty (30) days' prior notice to Attachment Customer, Company may conduct a field inspection of its Structures to verify the number, location and type of Attachment Customer's Attachments. If the field inspection reveals more Attachments than shown in Company's existing records, the additional Attachments shall be treated as Unauthorized Attachments.

14. INTERFERENCE OR HAZARD
If Company notifies Attachment Customer in writing or orally with written confirmation that the Attachment Customer's Attachments or the condition of Attachment Customer's Attachments on or in any Structure (i) interfere with the use of such Structure or the operation of Company facilities or equipment, (ii) constitute a hazard to the service rendered by Company or any other Persons permitted by Company to use such Structures, (iii) cause a danger to employees of Company or other Persons, or (iv) fail to comply with the Company's standards and applicable requirements of the NESC, NEC, and all other applicable codes, laws and regulations, the Attachment Customer shall, within a reasonable period, remove, rearrange, repair or change its Attachments as needed or as directed by Company. In the case of any immediate hazard or danger, such period shall not exceed twenty-four (24) hours from Attachment Customer's receipt of such notice. In case of a hazardous condition or other emergency which requires the immediate remove or relocation of the Attachment Customer's Attachments, the Company may at Attachment Customer's expense, without prior notice and with no liability therefor, remove or relocate such Attachments; provided however, that Company shall notify Attachment Customer of such action as soon as reasonably possible by any appropriate means, including by telephone.

15. REARRANGEMENT; RELOCATION OF STRUCTURES; NEW STRUCTURES
a. If Attachment Customer's Attachments can be accommodated on or in existing Structures only by rearranging Company facilities, or if because of Attachment Customer's proposed Attachments, Company rearranges or transfers its facilities on or in any facility not owned by it, Attachment Customer shall reimburse Company for the actual expense incurred in making such rearrangement or transfer.

b. Upon 45 days prior written notice delivered to Attachment Customer, Company may replace, relocate, or remove any Structure and cause the alteration, relocation or removal of any Attachment, consistent with normal operating, maintenance and development

The proposed LG&E Pole and Structure Attachment Charges Rate PSA (formerly named Rate CTAC) is contained on 20 pages instead of eight pages.

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procedures and prudent utility practices. In cases of emergency or dangerous situations, Company shall give only as much prior notice as practical under the circumstances. Company shall bear all costs and expenses of any relocation of the Structures not attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall bear all costs and expenses of any relocation and removal of the Attachments and all costs and expenses attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall be solely responsible for any losses occasioned by the interruption of Attachment Customer's business or operations and shall indemnify and hold Company harmless in connection with same.

c. If Company determines that any space occupied by the Attachments is required in connection with the services that the Company provides, Company may direct, by written notice to Attachment Customer, that such Attachments be removed from the Structures. Company shall use reasonable efforts to make space available as close in proximity as possible to the former Structures. Attachment Customer shall make such relocation within forty-five (45) days of the Company's request.

d. In the event a Person other than the Attachment Customer applies to make an Attachment to a Structure on which the Attachment Customer has placed an Attachment, and such application requires that Attachment Customer rearrange, transfer or relocate its Attachments, then Attachment Customer shall perform such rearrangement, transfer or relocation within 60 days of notice of such need to rearrange, transfer or relocate. Attachment Customer may condition its rearrangement, transfer or relocation upon reimbursement for the cost of such rearrangement, transfer or relocation. In the event Attachment Customer fails to perform such rearrangement, transfer or relocation within the time frame described above, the affected Attachments may be subject to rearrangement, transfer or relocation by the Person whose application necessitated the rearrangement, transfer or relocation to the extent permitted by law.

16. ABANDONMENT OF ATTACHMENT

Attachment Customer may at any time voluntarily remove its Attachments from any Structure, but shall immediately give Company written notice of such removal on the Company-prescribed form. Attachment Customer shall bear all cost of removal and any costs that Company incurs as a result of such removal and shall pay such costs within 30 days of receipt of an invoice. No refund of any amount paid for use of such Structure will result from Attachment Customer's voluntary removal nor shall such voluntary removal affect any other obligation or liability of Attachment Customer under this Schedule or the Attachment Customer Agreement.

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 40.14

Standard Rate PSA T

Pole and Structure Attachment Charges

17. INDEMNITIES

Attachment Customer shall protect, defend, indemnify and save harmless Company, its Affiliates, their officers, directors, employees and representatives from and against all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature, including but not limited to costs and expenses of defending against the same, payment of any settlement or judgment therefor and reasonable attorney's fees that are incurred in such defense, by reason of any claims arising from Attachment Customer's activities under this Schedule, or from Attachment Customer's presence on the Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives, including but not limited to claims alleging (1) injuries or deaths to Persons; (2) damage to or destruction of property including loss of use thereof; (3) power or communications outage, interruption or degradation; (4) pollution, contamination of or other adverse effects on the environment; (5) violation of governmental laws, regulations or orders; or (6) rearrangement, transfer, or removal of any third party attachment on, from, or to any Company Structure. The indemnity set forth in this section shall include indemnity for any claims arising out of the joint negligence of the Attachment Customer and Company.

18. UNAUTHORIZED ATTACHMENTS

If Attachment Customer makes any Attachment that requires Company approval under this Schedule and Attachment Customer Agreement and has not obtained such approval, the Attachment Customer shall pay a penalty for the Unauthorized Attachment equal to double the current Attachment charge. Attachment Customer shall also submit to Company an application for approval of the Unauthorized Attachment within 30 days of the attachment's discovery. If the Attachment Customer fails to submit the required applications or fails to timely remit any necessary payments to Company in connection with the application process (including but not limited to any make-ready fees necessary to accommodate the Unauthorized Attachments), Company may remove any or all such Unauthorized Attachments at Attachment Customer's expense.

19. DEFAULT

If Attachment Customer fails to pay any undisputed fee required, perform any material obligations undertaken or satisfy any warranty or representation made under the Attachment Customer Agreement or with any of the provisions of this Schedule or default in any of its obligations under this Tariff and shall fail within 30 days after written notice from Company to correct such default or non-compliance, Company may, at its option, terminate the license covering the Structures to which such default or non-compliance is applicable; remove,

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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The proposed LG&E Pole and Structure Attachment Charges Rate PSA (formerly named Rate CTAC) is contained on 20 pages instead of eight pages.

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relocate or rearrange at the Attachment Customer's expense the Attachments to which the default or non-compliance relates; or decline to permit additional Attachments until the failure or default is cured; by giving written notice to Attachment Customer of said termination. In the event of material or repeated default, Company may terminate the Attachment Customer Agreement and recover from the Attachment Customer all costs and expenses incurred as a result of reasonably related to the defaults. No refund of any attachment charge will be due on account of such termination.

20. TERMINATION

Either Company or Attachment Customer may terminate an Attachment Customer Agreement by providing the other written notice of termination at least 60 days prior to the end of the term of service.

Upon termination, Attachment Customer shall remove all Attachments from Structures and other Company property within 180 days. Attachment Customer shall bear all costs of such removal and shall exercise precautions to avoid damage to all Persons and to facilities of Company and other parties in so removing Attachments and assumes all responsibility for all damage it causes. If Attachment Customer's Attachments and other property are not removed within 180 days of termination of this Agreement, unless the time is extended by mutual agreement, Company may remove Attachment Customer's Attachments without liability and the Attachment Customer shall pay Company the cost of such removal within 30 days of receipt of an invoice.

Company may terminate an Attachment Customer Agreement without liability to Attachment Customer, upon giving 60 days advance written notice to the Attachment Customer that it has a reasonable belief that Company's performance under the Agreement would be illegal under applicable law or regulation or under any order or ruling issued by the PSC, or any other federal, state or local agency having regulatory jurisdiction over Company and same cannot be cured by Company without unreasonable expense or without materially and substantially altering the terms and conditions of the Attachment Customer Agreement; or that termination is required to preserve the Company's rights under any franchise, right-of-way, permit, easement or other similar right which is material and substantial to Company's business or operations. In the event of such termination, the Company and the Attachment Customer shall pay and perform obligations that have arisen prior to the effective date of termination, but shall not be obligated to pay and perform obligations, which arise after the effective date of termination.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

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Louisville Gas and Electric Company

Standard Rate PSA T
Pole and Structure Attachment Charges

21. WAIVER
Failure by the Company to enforce or insist upon compliance with any of the terms or conditions of this Agreement shall not constitute a general waiver or relinquishment of any such terms or conditions, but the same shall be and remain at all times in full force and effect.

22. INSURANCE
a. Throughout the term of service and so long as Attachment Customer's Attachments are on or in Company Structures, Attachment Customer shall provide and maintain the following insurance:

(1) Workers' Compensation and Employer's Liability Policy, which shall include: (a) Workers' Compensation (Coverage A), with statutory limits, and in accordance with the laws of Kentucky; (b) Employer's Liability (Coverage B) with minimum limits of $1,000,000 Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee; (c) 30 Day Cancellation Endorsement; and (d) Broad Form All States Endorsement.

(2) Commercial General Liability Policy, which shall have minimum limits of $1,000,000 each occurrence; $1,000,000 Products/Completed Operations Aggregate each occurrence; $1,000,000 Personal and Advertising Injury each occurrence, in all cases subject to $2,000,000 in the General Aggregate for all such claims, and including: (a) 30 Day Cancellation Endorsement; (b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by Company under the Attachment Customer Agreement; (c) Broad Form Property Damage; and (d) Insurance for liability arising out of blasting, collapse, and underground damage (deletion of X, C, U Exclusions).

(3) Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of $1,000,000 each occurrence.

(4) Umbrella/Excess Liability Insurance with minimum limits of $2,000,000 per occurrence; $2,000,000 aggregate, to apply to employer's liability, commercial general liability, and automobile liability.

(5) To the extent applicable, if any fixed wing or rotor craft aircraft will be used by Attachment Customer in performing the work, Aircraft Public Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury and property damage of $5,000,000 including passenger liability coverage.

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Louisville Gas and Electric Company

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(6) To the extent applicable, if engineering or other professional services will be separately provided by Attachment Customer as specified in the statements of work, then Professional Liability Insurance with limits of $3,000,000 per occurrence and $3,000,000 in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

b. Attachment Customer shall require its Contractors and subcontractors to provide and maintain the same insurance coverage as required of Attachment Customer.

c. Except with regard to workers' compensation and professional liability, each policy required under this schedule shall name Company as an additional insured and shall waive rights of subrogation against Company and Company's insurance carrier(s).

d. All policies shall be written by insurance companies that are licensed to do business in Kentucky and that are either satisfactory to Company or have a Best Rating of not less than "A-". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from Attachment Customer and the insurance carrier.

e. Company may request a summary of coverage of any of required policies or endorsements; but is not obligated to review any of Attachment Customer's certificates of insurance, insurance policies, or endorsements, or to advise Attachment Customer of any deficiencies in such documents. Company's receipt or review of such documents shall not relieve Attachment Customer from or be deemed a waiver of Attachment Customer's obligations to maintain insurance as provided.

f. Attachment Customer shall submit evidence of such coverage(s) to Company prior to the start of any work under the Attachment Customer Agreement and shall notify Company, prior to the commencement of any work pursuant to any statement of work and/or purchase order, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the Company's benefit

g. Attachment Customer shall provide notice of any accidents or claims involving Attachment Customer's Attachment or Attachment Customer's work under this Schedule and the Attachment Customer Agreement to the Company's designated representative.

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Louisville Gas and Electric Company

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23. PERFORMANCE ASSURANCE

Attachment Customer shall furnish a surety bond at the following times and in the following amounts and for the following purposes:

(a) During the period of the Attachment Customer's initial installation of its wireline pole attachments and at the time of any expansion involving more than 75 poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which the Attachment Customer intends to make a wireline pole attachment;

(b) Upon satisfactory completion of the Attachment Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);

(c) After Attachment Customer has been a customer of Company pursuant to the Attachment Agreement and is not in default under that agreement for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof)

(d) If an Attachment Customer proposes to attach a Wireless Facility or Facilities to a Structure, Attachment Customer shall post a surety bond in the amount of $1,500 for each pole to which a wireless attachment is attached. The amount of the bond shall not be reduced upon completion of installation or other event.

Each surety bond shall contain the provision that it shall not be terminated prior to six months after Company's receipt of written notice of the desire of the bonding or insurance company to terminate such bond. Company may waive this requirement if an acceptable replacement bond is received before the six months has ended. Upon receipt of such termination notice, Company shall request Attachment Customer to immediately remove its Cables, Wireless Facilities, Attachments and all other facilities from Company Structures. If Attachment Customer should fail to complete the removal of all of its facilities from Company's Structures within 30 days after receipt of such request, then Company may remove Attachment Customer's facilities at Attachment Customer's expense and without liability for any damage to Attachment Customer's facilities. Such bond shall guarantee the payment of any sums which may become due to attachment charges, inspections or work performed by Company under this Schedule or the Attachment Customer Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

Each surety bond shall be issued by an entity having a minimum corporate debt rating of A- by Standard & Poor's Financial Services LLC at the time of issuance and at all times the relevant bond is outstanding.

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24. NOTICES
Any notice, or request, required by this Schedule or the Attachment Customer Agreement shall be deemed properly given if sent overnight by nationally recognized overnight courier, sent by certified U.S. mail, return receipt requested, postage prepaid, or sent by telecopier with confirmed receipt, to Company's and Attachment Customer's designated representative. The designation of the representative to be notified, his address and/or telecopier number may be changed at any time by similar notice.

25. LIENS
To the extent permitted by law, in the event any construction lien or other encumbrance shall be placed on the Attachments as a result of the actions or omissions of Attachment Customer or its Contractor, Attachment Customer shall promptly, in accordance with applicable laws, discharge such lien or encumbrance without cost or expense to Company. Attachment Customer shall indemnify Company for any and all actual damages that may be suffered or incurred by Company in discharging or releasing said lien or encumbrance.

26. FORCE MAJEURE
In the event Attachment Customer or Company is delayed in or prevented from performing any of its respective obligations under an Attachment Customer Agreement or this Schedule due to acts of God, war, riots, civil insurrection, acts of the public enemy, strikes, lockouts, acts of civil or military authority, government shutdown, fires, floods, earthquakes, fiber, cable or other material failures, shortages or unavailability, delay in delivery not resulting from its failure to timely place orders therefor, lack or delay in transportation, or due to any other causes beyond its reasonable control, then such delay or nonperformance shall be excused.

27. LIMITATION OF LIABILITY
IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE TO ATTACHMENT CUSTOMER FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE, (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES AND (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 27 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 41

Standard Rate **EVSE**

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to customers to be served or currently being served under Company's Standard Rate Schedules GS (with energy usage of 500 kWh or higher per month), PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles.

Charging station is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas.

A basic underground service includes the charging station, existing transformer (or secondary pedestal) and 208/240 volt single-phase service, and necessary conductor and equipment typical of an underground service drop. Said service drop can originate from underground or overhead equipment. Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own and install all duct systems and associated equipment.

Where the location of existing facilities is not suitable, and Customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	**Single Charger**	**Dual Charger**
Monthly Charging Unit Fee:	$176.13	$293.10

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 41

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Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$183.66	$307.43	**T** **I**

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 41.1

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

ENERGY CONSUMPTION

Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 5,852 kilowatt-hours.

PAYMENT

The EVSE charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions in this Tariff Book, except as set out herein.

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the Customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.

4. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults.

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 41.1

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 41.2

Standard Rate **EVSE**

Electric Vehicle Supply Equipment

5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests installation of replacement facilities within five (5) years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

7. Temporary suspension of charging station is not permitted. Upon permanent discontinuance of service, charging station and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

8. Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE

The Monthly Charging Unit Fee shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

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P.S.C. Electric No. 11, Original Sheet No. 41.2

Standard Rate **EVSE**

Electric Vehicle Supply Equipment

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 42

Standard Rate **EVC**

Electric Vehicle Charging

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts the Company's fee structure for the vehicle charging service. EVC is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards.

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

RATE

Fee Per Hour: $ 2.85

Charging Unit Fee includes an Energy Charge and Adjustment Clauses

Charging sessions of less than a full hour will be prorated

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased in accordance with the following:

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 42

Standard Rate **EVC**

Electric Vehicle Charging

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts the Company's fee structure for the vehicle charging service. EVC is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards.

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

RATE

Fee Per Hour: $ 2.92 **I**

Charging Unit Fee includes an Energy Charge and Adjustment Clauses. **T**

Charging sessions of less than a full hour will be prorated. **T**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 42.1

Standard Rate **EVC**
Electric Vehicle Charging

TERMS AND CONDITIONS

1. Service shall be furnished under the following Terms and Conditions and excludes the Company's Terms and Conditions set out in this Tariff Book.

2. EV Customer is required to pay by means of credit card or Charging Station Supplier account.
   a. Credit Card must be chip enabled (if card is not chip enabled, Customer must call the Charging Station Supplier at toll-free number provided at station), or
   b. EV Customer is required to open a Charging Station Supplier account and accepts all terms and conditions of Charging Station Supplier.

3. Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay, or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

4. Company is merely a supplier of electricity delivered to the point of connection of Company's and charging station facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of EV Customer or of third persons resulting from the presence, use or abuse of electricity or resulting from defects in or accidents to any of EV Customer's wiring, equipment, or vehicle, or resulting from any cause whatsoever other than the negligence of Company.

5. In no event shall Company have any liability to EV Customer, the owner of a vehicle receiving charging service, or any other party affected by the electrical service to EV Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to EV Customer, the owner of a vehicle receiving charging service, or any other party. In the event that EV Customer's use of Company's service causes damage to Company's property or injuries to persons, EV Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

6. By connecting a vehicle to the Charging Station, the EV Customer represents that the EV Customer is authorized to operate that vehicle and to connect it to the Charging Station for the purpose of receiving vehicle charging service.

7. All service and maintenance will be performed only during regular scheduled working hours of Company.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 42.1

Standard Rate **EVC**
Electric Vehicle Charging

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   a. Credit Card must be chip enabled (if card is not chip enabled, Customer must call the Charging Station Supplier at toll-free number provided at station), or
   b. EV Customer is required to open a Charging Station Supplier account and accepts all terms and conditions of Charging Station Supplier.

3. Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay, or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

4. Company is merely a supplier of electricity delivered to the point of connection of Company's and charging station facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of EV Customer or of third persons resulting from the presence, use or abuse of electricity or resulting from defects in or accidents to any of EV Customer's wiring, equipment, or vehicle, or resulting from any cause whatsoever other than the negligence of Company.

5. In no event shall Company have any liability to EV Customer, the owner of a vehicle receiving charging service, or any other party affected by the electrical service to EV Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to EV Customer, the owner of a vehicle receiving charging service, or any other party. In the event that EV Customer's use of Company's service causes damage to Company's property or injuries to persons, EV Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

6. By connecting a vehicle to the Charging Station, the EV Customer represents that the EV Customer is authorized to operate that vehicle and to connect it to the Charging Station for the purpose of receiving vehicle charging service.

7. All service and maintenance will be performed only during regular scheduled working hours of Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 45

Standard Rate

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1), the customer will be charged $75.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Residential and general service customers may request and be granted temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected.

METER PULSE CHARGE

Where a customer desires and Company is willing to provide data meter pulses, a charge of $15.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

METER DATA PROCESSING CHARGE

A charge of $2.75 per report will be made to cover the cost of processing, generating, and providing recorder metered customer with profile reports. If a customer is not recorder metered and desires to have such metering installed, the customer will pay all costs associated with installing the recorder meter.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 45

Standard Rate **Special Charges**

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1), the customer will be charged $75.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Residential and general service customers may request and be granted temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected.

METER PULSE CHARGE

Where a customer desires and Company is willing to provide data meter pulses, a charge of $15.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

LG&E Special Charges is now contained on two pages instead of one page.

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 45.1

N

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter System (AMS) meter; or
5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 50

Standard Rate Rider **CSR**
Curtailable Service Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kVA individually. The aggregate service under CSR for Louisville Gas and Electric Company is limited to 100 MVA in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as of August 1, 2010.

CONTRACT OPTION
Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand in kVA. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 50

Standard Rate Rider **CSR**
Curtailable Service Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rider shall be limited to customers served under applicable power schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to January 1, 2017. Company will not enter into contracts for additional curtailable demand, even with customers already participating in this rider, on or after January 1, 2017. T

CONTRACT OPTION
Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. Customer's choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. T

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand in kVA. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Option B -- Customer may contract for a given amount of curtailable load in kVA by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand in kVA immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}.

Non-compliance for each requested physical curtailment shall be the measured positive value in kVA determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 6.40 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 6.50 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$16.00 per kVA

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Option B -- Customer may contract for a given amount of curtailable load in kVA by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand in kVA immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}.

Non-compliance for each requested physical curtailment shall be the measured positive value in kVA determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service:	$ 3.56 per kVA of Curtailable Billing Demand	**T/R**
Primary Voltage Service:	$ 3.67 per kVA of Curtailable Billing Demand	**T/R**

Non-Compliance Charge: $16.00 per kVA **T**

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 50.2

Standard Rate Rider **CSR**
Curtailable Service Rider

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M., (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday.

CERTIFICATION

Upon commencement of service hereunder, the Customer shall be required to demonstrate or certify to the Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 50.2

Standard Rate Rider **CSR**
Curtailable Service Rider

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M., (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the customer Designated Curtailable Load, as described above.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred. T T T

CERTIFICATION

Upon commencement of service hereunder, the Customer shall be required to demonstrate or certify to the Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Original Sheet No. 55
Canceling P.S.C. Electric No. 10, Original Sheet No. 55

Standard Rate Rider SQF
Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation.

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing month of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours)	$0.03581 per kWh
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours)	$0.02796 per kWh.
3. During all other hours (off-peak hours)	$0.03234 per kWh.

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company $0.03231 per kWh

DATE OF ISSUE: May 26, 2016

DATE EFFECTIVE: June 30, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 55

Standard Rate Rider SQF
Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation.

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing month of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours)	$0.03581 per kWh
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours)	$0.02796 per kWh.
3. During all other hours (off-peak hours)	$0.03234 per kWh.

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company $0.03231 per kWh

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: June 30, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 55.1

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

SELECTION OF RATE AND METERING

Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.

If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").

If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.

In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.

Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.

PAYMENT

Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, that, if Seller is a customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as customer.

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 55.1

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

SELECTION OF RATE AND METERING

Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.

If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").

If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.

In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.

Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.

PAYMENT

Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, that, if Seller is a customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as customer.

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 55.2

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).
2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.
3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.
4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.
5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a customer of Company. When Seller is a customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation,

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 55.2

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).
2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.
3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.
4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.
5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a customer of Company. When Seller is a customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation,

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 55.3

Standard Rate Rider **SQF**

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.
7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.
8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.
9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.
10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 55.3

Standard Rate Rider **SQF**

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.
7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.
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    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
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ISSUED BY: /s/ Robert M. Conroy, Vice President
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Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

Applicable to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

The hourly avoided energy cost (AEC) in $ per MWh, which is payable to a QF for delivery of energy, shall be equal to Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month. The total amount of the avoided energy cost payment to be made to a QF in an hour is equal to [AEC x E_{QF}], where E_{QF} is the amount of megawatt-hours delivered by a QF in that hour and which are determined by suitable metering.

Capacity Component Payments

The hourly avoided capacity cost (ACC) in $ per MWh, which is payable to a QF for delivery of capacity, shall be equal to the effective purchase price for power available to Company from the inter-utility market (which includes both energy and capacity charges) less Company's actual variable fuel expense (AEC). The total amount of the avoided capacity cost payment to be made to a QF in an hour is equal to [ACC x CAP_i], where CAP_i, the capacity delivered by the QF, is determined on the basis of the system demand (D_i) and Company's need for capacity in that hour to adequately serve the load.

Determination of CAP_i

For the following determination of CAP_i, $C_{LG\&E}$ represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

Applicable to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.

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Determination of CAP_i

For the following determination of CAP_i, $C_{LG\&E}$ represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 56.1

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{LG\&E}$; $CAP_i = 0$

2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

   $C_{LG\&E} < D_i \leq [C_{LG\&E} + C_{QF}]$; $CAP_i = C_M$

3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:

   $D_i > [C_{LG\&E} + C_{QF}]$; $CAP_i = C_{QF}$

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar days) of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit the Customer's account for such purchases.

TERM OF CONTRACT

For contracts which cover the purchase of energy only, the term shall be one (1) year, and shall be self-renewing from year-to-year thereafter, unless canceled by either party on one (1) year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be five (5) years.

TERMS AND CONDITIONS

1. Qualifying facilities shall be required to pay for any additional interconnection costs, to the extent that such costs are in excess of those that Company would have incurred if the qualifying facility's output had not been purchased.
2. A qualifying facility operating in parallel with Company must demonstrate that its equipment is designed, installed, and operated in a manner that insures safe and reliable interconnected operation. A qualifying facility should contact Company for assistance in this regard.
3. The purchasing, supplying and billing for service, and all conditions applying hereto, shall be specified in the contract executed by the parties, and are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Terms and Conditions currently in effect, as filed with the Commission.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: November 1, 1995

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 56.1

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{LG\&E}$; $CAP_i = 0$

2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

   $C_{LG\&E} < D_i \leq [C_{LG\&E} + C_{QF}]$; $CAP_i = C_M$

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PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar days) of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit the Customer's account for such purchases.

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For contracts which cover the purchase of energy only, the term shall be one (1) year, and shall be self-renewing from year-to-year thereafter, unless canceled by either party on one (1) year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be five (5) years.

TERMS AND CONDITIONS

1. Qualifying facilities shall be required to pay for any additional interconnection costs, to the extent that such costs are in excess of those that Company would have incurred if the qualifying facility's output had not been purchased.
2. A qualifying facility operating in parallel with Company must demonstrate that its equipment is designed, installed, and operated in a manner that insures safe and reliable interconnected operation. A qualifying facility should contact Company for assistance in this regard.
3. The purchasing, supplying and billing for service, and all conditions applying hereto, shall be specified in the contract executed by the parties, and are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Terms and Conditions currently in effect, as filed with the Commission.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57

Standard Rate Rider **NMS**

Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

DEFINITIONS

"Billing period" shall be the time period between the dates on which Company issues the customer's bills.

"Billing Period Credit" shall be the electricity generated by the customer that flows into the electric system and which exceeds the electricity supplied to the customer from the electric system during any billing period. A billing period credit is a kWh-denominated electricity credit only, not a monetary credit.

METERING AND BILLING

Net metering service shall be measured using a single meter or, as determined by Company, additional meters and shall be measured in accordance with standard metering practices by metering equipment capable of registering power flow in both directions for each time period defined by the applicable rate schedule. This net metering equipment shall be provided without any cost to the Customer. This provision does not relieve Customer's responsibility to pay metering costs embedded in the Company's Commission-approved base rates. Additional meters, requested by Customer, will be provided at Customer's expense.

If electricity generated by Customer and fed back to Company's system exceeds the electricity supplied to Customer from the system during a billing period, Customer shall receive a billing-period credit for the net delivery on Customer's bill for the succeeding billing periods. If Customer takes service under time-of-use or time-of-day rate schedule, Company will apply billing-period credits Customer creates in a particular time-of-day or time-of-use block only to offset net energy consumption in the same time-of-day or time-of-use blocks in any billing period. Any such unused excess billing-period credits will be carried forward and drawn on by Customer as needed. Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57

Standard Rate Rider **NMS**

Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

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If electricity generated by Customer and fed back to Company's system exceeds the electricity supplied to Customer from the system during a billing period, Customer shall receive a billing-period credit for the net delivery on Customer's bill for the succeeding billing periods. If Customer takes service under time-of-use or time-of-day rate schedule, Company will apply billing-period credits Customer creates in a particular time-of-day or time-of-use block only to offset net energy consumption in the same time-of-day or time-of-use blocks in any billing period. Any such unused excess billing-period credits will be carried forward and drawn on by Customer as needed. Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.1

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES

General – Customer shall operate the generating facility in parallel with Company's system under the following conditions and any other conditions required by Company where unusual circumstances arise not covered herein:

1. Customer to own, operate, and maintain all generating facilities on their premises. Such facilities shall include, but not be limited to, necessary control equipment to synchronize frequency, voltage, etc., between Customer's and Company's system as well as adequate protective equipment between the two systems. Customer's voltage at the point of interconnection will be the same as Company's system voltage.
2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.
3. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
4. Customer agrees to inform Company of any changes it wishes to make to its generating or associated facilities that differ from those initially installed and described to Company in writing and obtain prior approval from Company.
5. Company will have the right to inspect and approve Customer's facilities described herein, and to conduct any tests necessary to determine that such facilities are installed and operating properly; however, Company will have no obligation to inspect, witness tests, or in any manner be responsible for Customer's facilities or operation thereof.
6. Customer assumes all responsibility for the electric service on Customer's premises at and from the point of delivery of electricity from Company and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence or willful misconduct of Company.

Level 1 – A Level 1 installation is defined as an inverter-based generator certified as meeting the requirements of Underwriters Laboratories Standard 1741 and meeting the following conditions:

1. The aggregated net metering generation on a radial distribution circuit will not exceed 15% of the line section's most recent one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
2. The aggregated net metering generation on a shared singled-phase secondary will not exceed 20 kVA or the nameplate rating of the service transformer.
3. A single-phase net metering generator interconnected on the center tap neutral of a 240 volt service shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57.1

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES

General – Customer shall operate the generating facility in parallel with Company's system under the following conditions and any other conditions required by Company where unusual circumstances arise not covered herein:

1. Customer to own, operate, and maintain all generating facilities on their premises. Such facilities shall include, but not be limited to, necessary control equipment to synchronize frequency, voltage, etc., between Customer's and Company's system as well as adequate protective equipment between the two systems. Customer's voltage at the point of interconnection will be the same as Company's system voltage.
2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.
3. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
4. Customer agrees to inform Company of any changes it wishes to make to its generating or associated facilities that differ from those initially installed and described to Company in writing and obtain prior approval from Company.
5. Company will have the right to inspect and approve Customer's facilities described herein, and to conduct any tests necessary to determine that such facilities are installed and operating properly; however, Company will have no obligation to inspect, witness tests, or in any manner be responsible for Customer's facilities or operation thereof.
6. Customer assumes all responsibility for the electric service on Customer's premises at and from the point of delivery of electricity from Company and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence or willful misconduct of Company.

Level 1 – A Level 1 installation is defined as an inverter-based generator certified as meeting the requirements of Underwriters Laboratories Standard 1741 and meeting the following conditions:

1. The aggregated net metering generation on a radial distribution circuit will not exceed 15% of the line section's most recent one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
2. The aggregated net metering generation on a shared singled-phase secondary will not exceed 20 kVA or the nameplate rating of the service transformer.
3. A single-phase net metering generator interconnected on the center tap neutral of a 240 volt service shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.2

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

4. A net metering generator interconnected to Company's three-phase, three-wire primary distribution lines, shall appear as a phase-to-phase connection to Company's primary distribution line.
5. A net metering generator interconnected to Company's three-phase, four-wire primary distribution lines, shall appear as an effectively grounded source to Company's primary distribution line.
6. A net metering generator will not be connected to an area or spot network.
7. There are no identified violations of the applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8. Company will not be required to construct any facilities on its own system to accommodate the net metering generator.

Customer desiring a Level 1 interconnection shall submit a "LEVEL 1 - Application for Interconnection and Net Metering." Company shall notify Customer within 20 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 20 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Level 2 – A Level 2 installation is defined as generator that is not inverter-based; that uses equipment not certified as meeting the requirements of Underwriters Laboratories Standard 1741; or that does not meet one or more of the conditions required of a Level 1 net metering generator. A Level 2 Application will be approved if the generating facility meets the Company's technical interconnection requirements. Those requirements are available on line at www.lge-ku.com and upon request.

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Customer submitting a "Level 2 - Application for Interconnection and Net Metering" will provide a non-refundable inspection and processing fee of $100, and in the event that the Company determines an impact study to be necessary, shall be responsible for any reasonable costs of up to $1,000 of documented costs for the initial impact study.

Additional studies requested by Customer shall be at Customer's expense.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57.2

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

4. A net metering generator interconnected to Company's three-phase, three-wire primary distribution lines, shall appear as a phase-to-phase connection to Company's primary distribution line.
5. A net metering generator interconnected to Company's three-phase, four-wire primary distribution lines, shall appear as an effectively grounded source to Company's primary distribution line.
6. A net metering generator will not be connected to an area or spot network.
7. There are no identified violations of the applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8. Company will not be required to construct any facilities on its own system to accommodate the net metering generator.

Customer desiring a Level 1 interconnection shall submit a "LEVEL 1 - Application for Interconnection and Net Metering." Company shall notify Customer within 20 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 20 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Level 2 – A Level 2 installation is defined as generator that is not inverter-based; that uses equipment not certified as meeting the requirements of Underwriters Laboratories Standard 1741; or that does not meet one or more of the conditions required of a Level 1 net metering generator. A Level 2 Application will be approved if the generating facility meets the Company's technical interconnection requirements. Those requirements are available on line at www.lge-ku.com and upon request.

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Customer submitting a "Level 2 - Application for Interconnection and Net Metering" will provide a non-refundable inspection and processing fee of $100, and in the event that the Company determines an impact study to be necessary, shall be responsible for any reasonable costs of up to $1,000 of documented costs for the initial impact study.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.3

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.
2. Customer shall represent and warrant compliance of the net metering generator with:
   a) any applicable safety and power standards established by IEEE and accredited testing laboratories;
   b) NEC, as may be revised from time-to-time;
   c) Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Public Service Commission of Kentucky;
   d) the rules and regulations of the Public Service Commission of Kentucky, as may be revised by time-to-time by the Public Service Commission of Kentucky:
   e) all other local, state, and federal codes and laws, as may be in effect from time-to-time.
3. Any changes or additions to Company's system required to accommodate the net metering generator shall be Customer's financial responsibility and Company shall be reimbursed for such changes or additions prior to construction.
4. Customer shall operate the net metering generator in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. Customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system.
5. Customer shall be responsible for protecting, at Customer's sole cost and expense, the net metering generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the net metering generator resulting solely from the negligence or willful misconduct on the part of the Company.
6. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to Customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the net metering generator comply with the requirements of this rate schedule.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57.3

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.
2. Customer shall represent and warrant compliance of the net metering generator with:
   a) any applicable safety and power standards established by IEEE and accredited testing laboratories;
   b) NEC, as may be revised from time-to-time;
   c) Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Public Service Commission of Kentucky;
   d) the rules and regulations of the Public Service Commission of Kentucky, as may be revised by time-to-time by the Public Service Commission of Kentucky:
   e) all other local, state, and federal codes and laws, as may be in effect from time-to-time.
3. Any changes or additions to Company's system required to accommodate the net metering generator shall be Customer's financial responsibility and Company shall be reimbursed for such changes or additions prior to construction.
4. Customer shall operate the net metering generator in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. Customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system.
5. Customer shall be responsible for protecting, at Customer's sole cost and expense, the net metering generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the net metering generator resulting solely from the negligence or willful misconduct on the part of the Company.
6. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to Customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the net metering generator comply with the requirements of this rate schedule.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.4

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

7. Where required by the Company, Customer shall furnish and install on Customer's side of the point of interconnection a safety disconnect switch which shall be capable of fully disconnecting Customer's net metering generator from Company's electric service under the full rated conditions of Customer's net metering generator. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, Customer shall be responsible for ensuring the location of the EDS is
properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.
8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.
   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer's entire facility.
9. Customer agrees that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in net metering generator capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in net metering generator capacity is allowed without approval.
10. Customer shall protect, indemnify and hold harmless Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys' fees, for or on account of any injury or death

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State Regulation and Rates
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Louisville Gas and Electric Company

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Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

7. Where required by the Company, Customer shall furnish and install on Customer's side of the point of interconnection a safety disconnect switch which shall be capable of fully disconnecting Customer's net metering generator from Company's electric service under the full rated conditions of Customer's net metering generator. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, Customer shall be responsible for ensuring the location of the EDS is
properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.
8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.
   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer's entire facility.
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.5

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating Customer's net metering generator or any related equipment or any facilities owned by Company, except where such injury, death or damage was caused or contributed to by the fault or negligence of Company or its employees, agents, representatives or contractors. The liability of Company to Customer for injury to person and property shall be governed by the tariff(s) for the class of service under which Customer is taking service.

11. Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial or other policy) for generating facilities. Customer shall upon request provide Company with proof of such insurance at the time that application is made for net metering.
12. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.
13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.
14. Customer shall retain any and all Renewable Energy Credits (RECs) generated by Customer's generating facilities.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57.5

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating Customer's net metering generator or any related equipment or any facilities owned by Company, except where such injury, death or damage was caused or contributed to by the fault or negligence of Company or its employees, agents, representatives or contractors. The liability of Company to Customer for injury to person and property shall be governed by the tariff(s) for the class of service under which Customer is taking service.

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13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.
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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.6

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 1

Application for Interconnection and Net Metering

Use this application form only for a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Submit this Application to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________

Customer Address: ____

Customer Phone No.: ______________ Customer E-mail Address: ________________

Project Contact Person: ____

Phone No.: ______________ E-mail Address (Optional): ________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ______________

Is Battery Storage Used: ____No ____Yes If Yes, Battery Power Rating: ______________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, *(optional: Utility accessible disconnect switch)* and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: November 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57.6

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 1

Application for Interconnection and Net Metering

Use this application form only for a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Submit this Application to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________

Customer Address: ____

Customer Phone No.: ______________ Customer E-mail Address: ________________

Project Contact Person: ____

Phone No.: ______________ E-mail Address (Optional): ________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ______________

Is Battery Storage Used: ____No ____Yes If Yes, Battery Power Rating: ______________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, *(optional: Utility accessible disconnect switch)* and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ______________________

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.7

Standard Rate Rider **NMS**
Net Metering Service

<u>LEVEL 2</u>

<u>Application for Interconnection and Net Metering</u>
Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or does not meet any of the additional conditions under Level 1.

Submit this Application, along with an application fee of $100, to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ________________________ Account Number: ________________

Customer Address: ____

Project Contact Person: ____

Phone No.: ________________ E-mail Address (Optional): ________________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Total Generating Capacity of Generating Facility: ________________________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point *of* interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by *a* nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ________________________________ Date: ________________

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: November 1, 2010

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 57.7

Standard Rate Rider **NMS**
Net Metering Service

<u>LEVEL 2</u>

<u>Application for Interconnection and Net Metering</u>
Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or does not meet any of the additional conditions under Level 1.

Submit this Application, along with an application fee of $100, to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ________________________ Account Number: ________________

Customer Address: ____

Project Contact Person: ____

Phone No.: ________________ E-mail Address (Optional): ________________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Total Generating Capacity of Generating Facility: ________________________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point *of* interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ________________________________ Date: ________________

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 60

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY
In all territory served.

AVAILABILITY OF SERVICE
This rider is available for non-standard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to line extensions or to other facilities which are necessary to provide basic electric service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term.

DEFINITION OF EXCESS FACILITIES
Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters.

EXCESS FACILITIES CHARGE
Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With No Contribution-in-Aid-of-Construction 1.32%

(b) making a one-time Contribution–in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage with Contribution-in-Aid-of-Construction 0.54%

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 60

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY
In all territory served.

AVAILABILITY OF SERVICE
This rider is available for non-standard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to line extensions or to other facilities which are necessary to provide basic electric service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term.

DEFINITION OF EXCESS FACILITIES
Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters.

EXCESS FACILITIES CHARGE
Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With No Contribution-in-Aid-of-Construction 1.32%

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Percentage with Contribution-in-Aid-of-Construction 0.54%

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 60.1

Standard Rate Rider **EF**
Excess Facilities

PAYMENT

The Excess Facilities Charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

TERM OF CONTRACT

The initial term of contract to the customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 60.1

Standard Rate Rider **EF**
Excess Facilities

PAYMENT

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The initial term of contract to the customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 61

Standard Rate Rider **RC**
Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has, and is willing, to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.43 per kW/kVA per Month
Primary Distribution	$1.26 per kW/kVA per Month

Applicable to the greater of:
(1) the highest average load in kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) recorded at either the principal distribution feed metering point or at the redundant distribution feed metering point during any 15-minute interval in the monthly billing period,
(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months, or
(3) the contracted capacity reservation.

TERM OF CONTRACT

The minimum contract term shall be five (5) years, and shall be renewed for one (1) year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement. Company may require that a contract be executed for a longer initial term when deemed necessary by the difficulty and/or high cost associated with providing the redundant feed or other special conditions.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 61

Standard Rate Rider **RC**
Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has, and is willing, to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.66 per kW/kVA per Month	I
Primary Distribution	$1.50 per kW/kVA per Month	I

Applicable to the greater of:
(1) the highest average load in kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) recorded at either the principal distribution feed metering point or at the redundant distribution feed metering point during any 15-minute interval in the monthly billing period,
(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months, or
(3) the contracted capacity reservation.

TERM OF CONTRACT

The minimum contract term shall be five (5) years, and shall be renewed for one (1) year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement. Company may require that a contract be executed for a longer initial term when deemed necessary by the difficulty and/or high cost associated with providing the redundant feed or other special conditions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 62

Standard Rate Rider **SS**
Supplemental or Standby Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This service is available as a rider to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than those of Company and who desire to contract with Company for reserve, breakdown, supplemental or standby service.

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

RATE

	Secondary	Primary	Transmission
Contract Demand per kW/kVA per Month:	$13.57	$12.30	$10.83

CONTRACT DEMAND
Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) mutually agreed upon as representing Customer's maximum service requirements and contracted for by Customer; provided, however, if such number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) is exceeded by a recorded demand, such recorded demand shall become the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE
Company will bill Customer monthly for all of the charges under Customer's applicable rate schedule, including, but not limited to, the applicable basic service charge, energy charges, and adjustment clauses. In addition to those charges, Company will bill Customer monthly a demand charge that is the greater of: (1) the Customer's total demand charge calculated under the applicable rate schedule; or (2) the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand. If Customer's applicable rate schedule does not contain a demand charge, the Customer's monthly demand charge will be the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

LG&E Supplemental or Standby Service Rate SS is proposed to be eliminated.

Louisville Gas and Electric Company

Standard Rate Rider **SS**
Supplemental or Standby Service

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

SPECIAL TERMS AND CONDITIONS

1) In order to protect its equipment from overload damage, Company may require customer to install at Customer's own expense an approved shunt trip type breaker and an approved automatic pole-mounted disconnect. Such circuit breakers shall be under the sole control of Company and will be set by Company to break the connection with its service in the event Customer's demand materially exceeds that for which Customer contracted.

2) In the event Customer's use of service is intermittent or subject to violent fluctuations, Company will require Customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

3) Customer's generating equipment shall not be operated in parallel with Company's service until the manner of such operation has been approved by Company and is in compliance with Company's operating standards for system reliability and safety.

TERM OF CONTRACT
The minimum contract period shall be one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of load or special conditions.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions except as provided herein.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

LG&E Supplemental or Standby Service Rate SS is proposed to be eliminated.

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 65

Standard Rate Rider **IL**
Rider for Intermittent Loads

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

RATE

1. A contribution in aid of construction or an excess facilities charge shall be required for all special or added facilities, if any, necessary to serve such loads, as provided under the Excess Facilities Rider.
2. Plus the charges provided for under the rate schedule applicable, including any Basic Service Charge if applicable, Energy Charge, Maximum Load Charge (if load charge rate is used), Fuel Clause and the Minimum Charge under such rate adjusted in accordance with (a) or (b) herein.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 4, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 65

Standard Rate Rider **IL**
Rider for Intermittent Loads

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. Company shall be held harmless for any damages or economic loss resulting from such termination of service. If requested by Company, Customer shall provide all available information to Company that aids Company in enforcing its service standards. If Company at any time has a reasonable basis for believing that Customer's proposed or existing use of the service provided will not comply with the service standards for interference, fluctuations, or harmonics, Company may engage such experts and/or consultants as Company shall determine are appropriate to advise Company in ensuring that such interference, fluctuations, or harmonics are within acceptable standards. Should such experts and/or consultants determine Customer's use of service is unacceptable, Company's use of such experts and/or consultants will be at the Customer's expense.

RATE

1. A contribution in aid of construction or an excess facilities charge shall be required for all special or added facilities, if any, necessary to serve such loads, as provided under the Excess Facilities Rider.
2. Plus the charges provided for under the rate schedule applicable, including any Basic Service Charge if applicable, Energy Charge, Maximum Load Charge (if load charge rate is used), Fuel Clause and the Minimum Charge under such rate adjusted in accordance with (a) or (b) herein.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 65.1

Standard Rate Rider **IL**
Rider for Intermittent Loads

RATE (continued)

(a) If rate schedule calls for a minimum based on the total kW of connected load, each kVA of such special equipment shall be counted as one kW connected load for minimum billing purposes.

(b) If rate schedule calls for a minimum based on the 15-minute integrated load, and such loads operate only intermittently so that the kW registered on a standard 15-minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each kVA of such special equipment shall be counted as one-third kW load for minimum billing purposes.

MINIMUM CHARGE
As determined by this Rider and the Rate Schedule to which it is attached.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 65.1

Standard Rate Rider **IL**
Rider for Intermittent Loads

RATE (continued)

(a) If rate schedule calls for a minimum based on the total kW of connected load, each kVA of such special equipment shall be counted as one kW connected load for minimum billing purposes.

(b) If rate schedule calls for a minimum based on the 15-minute integrated load, and such loads operate only intermittently so that the kW registered on a standard 15-minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each kVA of such special equipment shall be counted as one-third kW load for minimum billing purposes.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 66

Standard Rate Rider **TS**

Temporary and/or Seasonal Electric Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of the Company where:

1. Customer's business does not require permanent installation of Company's facilities, excluding service provided for construction of permanent delivery points for residences and commercial buildings, and is of such nature to require only seasonal service or temporary service; or
2. the service is over 50 kW, provided for construction purposes, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or
3. where Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment.

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 2 or 3, above, the Company will determine the term of service, which shall not exceed one (1) year.

CONDITIONS

Company may permit such electric loads to be served on the rate schedule normally applicable, but without requiring a yearly contract and minimum, substituting therefore the following conditions and agreements:

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.

2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above plus a monthly charge for the salvageable equipment at the Percentage With No Contribution -in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 66

Standard Rate Rider **TS**

Temporary/Seasonal Electric Service **T**

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of the Company where:

1. Customer's business does not require permanent installation of Company's facilities, excluding service provided for construction of permanent delivery points for residences and commercial buildings, and is of such nature to require only seasonal service or temporary service; or

2. the service is over 50 kW, provided for construction purposes, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or

3. where Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment.

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 2 or 3, above, the Company will determine the term of service, which shall not exceed one (1) year.

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2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above plus a monthly charge for the salvageable equipment at the Percentage With No Contribution -in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is from dusk to dawn as shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

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HOURS USE TABLE

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MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 70

Standard Rate Rider **SGE**
Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: June 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00467 dated February 22, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 70

Standard Rate Rider **SGE**
Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: June 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00467 dated February 22, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 70.1

Standard Rate Rider **LGE**

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 70.1

Standard Rate Rider **LGE**

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 71

Standard Rate Rider **EDR**
Economic Development Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE
A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS
Brownfield Development
a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to minimum monthly billing loads of 500 kVA (or kW as is appropriate) or greater where the customer takes service from existing Company facilities.

Economic Development
c) Service under EDR for Economic Development is available to:
   1) new customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate); and

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 71

Standard Rate Rider **EDR**
Economic Development Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE
A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS
Brownfield Development
a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to minimum monthly billing loads of 500 kVA (or kW as is appropriate) or greater where the customer takes service from existing Company facilities.

Economic Development
c) Service under EDR for Economic Development is available to:
   1) new customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate); and

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS
Economic Development

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined as follows:
   i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
   ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
   iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
   1) a description of the new load to be served;
   2) the number of new employees, if any, Customer anticipates employing associated with the new load;
   3) the capital investment Customer anticipates making associated with the EDR load;
   4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

e) Should Company determine a refundable contribution for the capital investment in Customer-specific facilities required by Company to serve the EDR load would ordinarily be required as set out under Company's Line Extension Plan, I. Special Cases, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.

g) Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which Company initiates service to Customer.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS
Economic Development

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined as follows:
   i. Company and the existing customer will determine Customer's Existing Base Load by calculating a 12-month rolling average of measured demand. **T**
   ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
   iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

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   1) a description of the new load to be served;
   2) the number of new employees, if any, Customer anticipates employing associated with the new load;
   3) the capital investment Customer anticipates making associated with the EDR load;
   4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

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General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 71.2

Standard Rate Rider **EDR**
Economic Development Rider

General (continued)

h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.
i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.
j) In any billing month where Customer's metered load is less than the load required to be eligible for either Brownfield Development or Economic Development, no credit under EDR will be calculated or applied to Customer's billing.

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 71.2

Standard Rate Rider **EDR**
Economic Development Rider

General (continued)

h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.
i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.
j) In any billing month where Customer's metered load is less than the load required to be eligible for either Brownfield Development or Economic Development, no credit under EDR will be calculated or applied to Customer's billing.

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 72 N

Standard Rate Rider **SSP**
Solar Share Program Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This optional, voluntary service is available to Company's customers taking service under any Standard Rate Schedule except those served under Retail Transmission Service, Fluctuating Load Service, Lighting Service, Restricted Lighting Service, Lighting Energy Service, Traffic Energy Service, Cable Television Attachment Charges, Electric Vehicle Supply Equipment, and Electric Vehicle Charging Service rate schedules. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

RATE:

Upfront Fee

Subscription Fee	$40.00 per quarter-kW subscribed

Monthly Charge

Solar Capacity Charge	$6.29 per quarter-kW subscribed

Monthly Credits and Adjustments

	Rate Schedule	Credit per kWh
Solar Energy Credit (per kWh of pro rata energy produced by the Solar Share Facilities; number of kWh eligible for credit limited to customer's net kWh consumption on each bill)	RS	$0.04020
	RTOD-Energy	$0.04020
	RTOD-Demand	$0.04020
	VFD	$0.04020
	GS	$0.04021
	PS Secondary	$0.04071
	PS Primary	$0.03925
	TODS	$0.04049
	TODP	$0.03824

Solar FAC Adjustment	Subscriber's billing under Adjustment Clause FAC will be adjusted corresponding to number of kWh to which Solar Energy Credit applies

DATE OF ISSUE: November 9, 2016

DATE EFFECTIVE: November 4, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00274 dated November 4, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 72

Standard Rate Rider **SSP**
Solar Share Program Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This optional, voluntary service is available to Company's customers taking service under any Standard Rate Schedule except those served under Retail Transmission Service, Fluctuating Load Service, Lighting Service, Restricted Lighting Service, Lighting Energy Service, Traffic Energy Service, Pole and Structure Attachment Charges, Electric Vehicle Supply Equipment, T and Electric Vehicle Charging Service rate schedules. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

RATE:

Upfront Fee

Subscription Fee	$40.00 per quarter-kW subscribed

Monthly Charge

Solar Capacity Charge	$6.29 per quarter-kW subscribed

Monthly Credits and Adjustments

	Rate Schedule	Credit per kWh
Solar Energy Credit (per kWh of pro rata energy produced by the Solar Share Facilities; number of kWh eligible for credit limited to customer's net kWh consumption on each bill)	RS	$0.04020
	RTOD-Energy	$0.04020
	RTOD-Demand	$0.04020
	VFD	$0.04020
	GS	$0.04021
	PS Secondary	$0.04071
	PS Primary	$0.03925
	TODS	$0.04049
	TODP	$0.03824

Solar FAC Adjustment	Subscriber's billing under Adjustment Clause FAC will be adjusted corresponding to number of kWh to which Solar Energy Credit applies

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 72.1 N

Standard Rate Rider **SSP**

Solar Share Program Rider

PROGRAM DESCRIPTION

The Solar Share Program is an optional, voluntary program that allows customers to subscribe capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer (“Subscriber”) may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility. Payment of the Subscription Fee for the amount of capacity a customer seeks to subscribe will be due at the time of subscription. The Subscription Fee is a non-refundable administrative and customer education fee.

After subscribing and paying the Subscription Fee, Subscriber will pay the monthly Solar Capacity Charge for each quarter-kW subscribed beginning with the first billing period in which the subscribed capacity has been in service for the entire billing period. For each such billing period, Subscriber will also receive (i) a bill credit in the amount of the monthly Solar Energy Credit (see Rate above) times the pro rata amount of energy production attributable to Subscriber’s subscribed capacity (limited by Subscriber’s net kWh consumption for the period being billed) and (ii) a bill adjustment to the Subscriber’s Fuel Adjustment Clause (FAC) credits or charges corresponding to the number of kWh for which the Subscriber receives a Solar Energy Credit.

Customers subscribing less than 50 kW DC will not be required to enter into a contract concerning their subscriptions; however, a customer may not reduce or cancel a subscription earlier than 12 months from the date of the customer’s most recent change to the customer’s subscription level. Therefore, a customer subscribing less than 50 kW has a 12-month commitment from the date of the customer’s initial subscription, and may have a longer commitment if the customer subsequently increases subscribed capacity (which a customer may do at any time upon paying a Subscription Fee for the additional capacity) or if the customer chooses to decrease but not cancel the subscription after the initial 12 months. As addressed in Term of Contract below, customers subscribing 50 kW DC or more must enter into a 5-year contract with Company.

TERMS AND CONDITIONS

1) Subscriptions will be available on a first-come first-served basis, except that 25% of the capacity of Solar Share Facility No. 1 will be available only to residential customers for the first 45 days of the initial subscription period for new facility. Otherwise, all capacity in the Solar Share Facilities will be available for subscription by all customers on a first-come, first-served basis.

2) Individual subscriptions will be available in nominal 250 W DC (quarter-kW) increments.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 72.1

Standard Rate Rider **SSP**

Solar Share Program Rider

PROGRAM DESCRIPTION

The Solar Share Program is an optional, voluntary program that allows customers to subscribe capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer (“Subscriber”) may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility. Payment of the Subscription Fee for the amount of capacity a customer seeks to subscribe will be due at the time of subscription. The Subscription Fee is a non-refundable administrative and customer education fee.

After subscribing and paying the Subscription Fee, Subscriber will pay the monthly Solar Capacity Charge for each quarter-kW subscribed beginning with the first billing period in which the subscribed capacity has been in service for the entire billing period. For each such billing period, Subscriber will also receive (i) a bill credit in the amount of the monthly Solar Energy Credit (see Rate above) times the pro rata amount of energy production attributable to Subscriber’s subscribed capacity (limited by Subscriber’s net kWh consumption for the period being billed) and (ii) a bill adjustment to the Subscriber’s Fuel Adjustment Clause (FAC) credits or charges corresponding to the number of kWh for which the Subscriber receives a Solar Energy Credit.

Customers subscribing less than 50 kW DC will not be required to enter into a contract concerning their subscriptions; however, a customer may not reduce or cancel a subscription earlier than 12 months from the date of the customer’s most recent change to the customer’s subscription level. Therefore, a customer subscribing less than 50 kW has a 12-month commitment from the date of the customer’s initial subscription, and may have a longer commitment if the customer subsequently increases subscribed capacity (which a customer may do at any time upon paying a Subscription Fee for the additional capacity) or if the customer chooses to decrease but not cancel the subscription after the initial 12 months. As addressed in Term of Contract below, customers subscribing 50 kW DC or more must enter into a 5-year contract with Company.

TERMS AND CONDITIONS

1) Subscriptions will be available on a first-come first-served basis, except that 25% of the capacity of Solar Share Facility No. 1 will be available only to residential customers for the first 45 days of the initial subscription period for new facility. Otherwise, all capacity in the Solar Share Facilities will be available for subscription by all customers on a first-come, first-served basis.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 72.2 **N**

Standard Rate Rider **SSP**

Solar Share Program Rider

TERMS AND CONDITIONS (continued)

3) Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC. No customer may subscribe more than 250 kW DC in any single Solar Share Facility.

4) All Subscription Fees are non-refundable.

5) Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.

6) Customers may not owe any arrearage prior to participating in the Solar Share Program.

7) Subscribers' pro-rata share of the electricity produced by the Solar Share Facilities will be determined on a billing cycle basis. The corresponding Solar Energy Credit (per kWh) and Solar FAC Adjustment will appear on the Subscriber's bill.

8) Subscriber may continue to participate in the Program without incurring new or additional Subscription Fees if Subscriber changes premises within the combined Kentucky certified electric service territories of Louisville Gas and Electric Company and Kentucky Utilities Company. For clarity, changing premises does not exempt Subscriber from additional Subscription Fees for any additional capacity Subscriber elects to subscribe before, during, or after changing premises.

9) Subscribers whose customer accounts are closed for any reason will not be able to remain in the Program. Any such former Subscriber who reestablishes service with Company and seeks again to subscribe will have to pay again the Subscription Fee associated with the amount of capacity desired.

10) Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a subscription any time after 12 months following the date of the most recent change to Subscriber's subscription; however, any re-subscription will require Subscriber to pay Subscription Fees for all capacity re-subscribed, as well as for any capacity subscribed beyond Subscriber's original subscription. Similarly, if Subscriber decreases and later increases subscribed capacity, Company will require Subscriber to pay Subscription Fees for the re-subscribed capacity as well as any net new capacity subscribed. Decreases in subscribed amounts will not result in refunds of Subscription Fees to Subscriber.

11) Unless constrained by contract (see Term of Contract below), Subscriber may also increase subscribed capacity at any time. Increases in subscribed capacity will require payment of additional Subscription Fees.

DATE OF ISSUE: November 9, 2016

DATE EFFECTIVE: November 4, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00274 dated November 4, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 72.2

Standard Rate Rider **SSP**

Solar Share Program Rider

TERMS AND CONDITIONS (continued)

3) Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC. No customer may subscribe more than 250 kW DC in any single Solar Share Facility.

4) All Subscription Fees are non-refundable.

5) Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.

6) Customers may not owe any arrearage prior to participating in the Solar Share Program.

7) Subscribers' pro-rata share of the electricity produced by the Solar Share Facilities will be determined on a billing cycle basis. The corresponding Solar Energy Credit (per kWh) and Solar FAC Adjustment will appear on the Subscriber's bill.

8) Subscriber may continue to participate in the Program without incurring new or additional Subscription Fees if Subscriber changes premises within the combined Kentucky certified electric service territories of Louisville Gas and Electric Company and Kentucky Utilities Company. For clarity, changing premises does not exempt Subscriber from additional Subscription Fees for any additional capacity Subscriber elects to subscribe before, during, or after changing premises.

9) Subscribers whose customer accounts are closed for any reason will not be able to remain in the Program. Any such former Subscriber who reestablishes service with Company and seeks again to subscribe will have to pay again the Subscription Fee associated with the amount of capacity desired.

10) Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a subscription any time after 12 months following the date of the most recent change to Subscriber's subscription; however, any re-subscription will require Subscriber to pay Subscription Fees for all capacity re-subscribed, as well as for any capacity subscribed beyond Subscriber's original subscription. Similarly, if Subscriber decreases and later increases subscribed capacity, Company will require Subscriber to pay Subscription Fees for the re-subscribed capacity as well as any net new capacity subscribed. Decreases in subscribed amounts will not result in refunds of Subscription Fees to Subscriber.

11) Unless constrained by contract (see Term of Contract below), Subscriber may also increase subscribed capacity at any time. Increases in subscribed capacity will require payment of additional Subscription Fees.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00274 dated November 4, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 72.3 **N**

Standard Rate Rider **SSP**

Solar Share Program Rider

TERMS AND CONDITIONS (continued)

12) Each subscription under the Solar Share Program applies to a particular meter. Subscribers with multiple meters may obtain multiple subscriptions, one per meter. But Company will not aggregate usage across multiple meters for applying credits, charges, or adjustments under Rider SSP; credits, charges, and adjustments under Rider SSP apply only to the meter associated with the subscription. The only exception to this restriction is if Subscriber has more than one meter for a single service, which multiple meters Company installed for its own operating convenience and bills on an aggregated basis in accordance with Company's Terms and Conditions.

13) Subscriptions are not transferrable or assignable between customers or between a single customer's meters.

14) Subscriber's Solar Energy Credit and corresponding Solar FAC Adjustment will apply each billing cycle to the Subscriber's pro rata amount of AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) or Subscriber's net energy consumption (kWh) for the billing period, whichever is less.

15) For all customers taking service under both of Riders NMS and SSP, Company will apply all provisions of Rider NMS to their bills before applying charges and credits under Rider SSP, including applying the Solar Energy Credit and Solar FAC Adjustment to such customers' net energy consumption. Therefore, customers should note that in months in which a customer taking service under Riders SSP and NMS has net zero energy consumption or net energy production under the terms of Rider NMS—including carryover net-energy credits from previous months, if any—the customer will receive zero Solar Energy Credit and Solar FAC Adjustment under Rider SSP. These provisions apply regardless of whether a customer first took service under Rider NMS before taking service under Rider SSP or vice versa, or if a customer began taking service under both riders simultaneously.

16) All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired.

17) Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use.

18) Service will be furnished under Company's Terms and Conditions except as provided herein.

TERM OF CONTRACT

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

DATE OF ISSUE: November 9, 2016

DATE EFFECTIVE: November 4, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00274 dated November 4, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 72.3

Standard Rate Rider **SSP**

Solar Share Program Rider

TERMS AND CONDITIONS (continued)

12) Each subscription under the Solar Share Program applies to a particular meter. Subscribers with multiple meters may obtain multiple subscriptions, one per meter. But Company will not aggregate usage across multiple meters for applying credits, charges, or adjustments under Rider SSP; credits, charges, and adjustments under Rider SSP apply only to the meter associated with the subscription. The only exception to this restriction is if Subscriber has more than one meter for a single service, which multiple meters Company installed for its own operating convenience and bills on an aggregated basis in accordance with Company's Terms and Conditions.

13) Subscriptions are not transferrable or assignable between customers or between a single customer's meters.

14) Subscriber's Solar Energy Credit and corresponding Solar FAC Adjustment will apply each billing cycle to the Subscriber's pro rata amount of AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) or Subscriber's net energy consumption (kWh) for the billing period, whichever is less.

15) For all customers taking service under both of Riders NMS and SSP, Company will apply all provisions of Rider NMS to their bills before applying charges and credits under Rider SSP, including applying the Solar Energy Credit and Solar FAC Adjustment to such customers' net energy consumption. Therefore, customers should note that in months in which a customer taking service under Riders SSP and NMS has net zero energy consumption or net energy production under the terms of Rider NMS—including carryover net-energy credits from previous months, if any—the customer will receive zero Solar Energy Credit and Solar FAC Adjustment under Rider SSP. These provisions apply regardless of whether a customer first took service under Rider NMS before taking service under Rider SSP or vice versa, or if a customer began taking service under both riders simultaneously.

16) All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired.

17) Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use.

18) Service will be furnished under Company's Terms and Conditions except as provided herein.

TERM OF CONTRACT

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 4, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00274 dated November 4, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 75

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or currently being served under Company's Standard Rate Schedules GS (with energy usage of 500 kWh or higher per month), PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles, whereby the Customer installs and owns facilities on its side of the point of delivery of the energy supplied hereunder necessary to serve Company-provided charging station.

Charging station under this rider is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas. Customer is responsible for providing the appropriate voltage levels and connections necessary to operate Company-provided charger.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by customer prior to service commencing.

RATE	**Single Charger**	**Dual Charger**
Monthly Charging Unit Fee:	$132.49	$205.83

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

PAYMENT
The EVSE-R charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 75

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as a rider to customers to be served or currently being served under Company's Standard Rate Schedules GS (with energy usage of 500 kWh or higher per month), PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles, whereby the Customer installs and owns facilities on its side of the point of delivery of the energy supplied hereunder necessary to serve Company-provided charging station.

Charging station under this rider is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas. Customer is responsible for providing the appropriate voltage levels and connections necessary to operate Company-provided charger.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$133.77	$207.65	**T** **I**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

PAYMENT
The EVSE-R charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions set out in this Tariff Book, except as set out herein.
2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.
3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.
4. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults.
5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement facilities within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.
7. Temporary suspension of charging station is not permitted. Upon permanent discontinuance of service, charging station and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Louisville Gas and Electric Company

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions set out in this Tariff Book, except as set out herein.
2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.
3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.
4. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults.
5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 75.2

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

8. Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE
As determined by this Rider and the Rate Schedule to which it is attached.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 75.2

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

8. Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE
As determined by this Rider and the Rate Schedule to which it is attached.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 85

Adjustment Clause **FAC**
Fuel Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where "F" is the expense of fossil fuel and "S" is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below:

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages, plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 85

Adjustment Clause **FAC**
Fuel Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where "F" is the expense of fossil fuel and "S" is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below:

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages, plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 85.1

Adjustment Clause **FAC**
Fuel Adjustment Clause

(3) Forced Outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (2)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(4) Sales (S) shall be all kWh sold, excluding inter-system sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(6) Base (b) period shall be April 2012 and the base fuel factor is $0.02725 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Orders in Case No. 2012-00553 dated May 17, 2013, and May 29, 2013, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2013, which begins June 26, 2013.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: With Bills Rendered On and After
June 26, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the Public Service Commission in Case No. 2012-00553 dated May 17, 2013 and May 29, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 85.1

Adjustment Clause **FAC**
Fuel Adjustment Clause

(3) Forced Outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (2)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(4) Sales (S) shall be all kWh sold, excluding inter-system sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(6) Base (b) period shall be April 2012 and the base fuel factor is $0.02725 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Orders in Case No. 2012-00553 dated May 17, 2013, and May 29, 2013, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2013, which begins June 26, 2013.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: With Bills Rendered On and After
June 26, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the Public Service Commission in Case No. 2012-00553 dated May 17, 2013 and May 29, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time of Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS. Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees, and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for each such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time of Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS. Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per kilowatt hour of monthly consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees, and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of approved programs shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DCR for each such rate class.

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Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.1

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Residential Time-of-Day Energy Service, Volunteer Fire Department, and General Service customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, RTOD-Energy, VFD, and GS rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules RTOD-Demand, PS, TODS, TODP, and RTS) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved

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Louisville Gas and Electric Company

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

1) For each upcoming twelve-month period, the estimated reduction in customer usage (in kWh) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered hereunder from each customer class. The non-variable revenue requirement for the Residential, Residential Time-of-Day Energy Service, Volunteer Fire Department, and General Service customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, RTOD-Energy, VFD, and GS rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules RTOD-Demand, PS, TODS, TODP, and RTS) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.2

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

The DSM incentive amount related to programs for Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT

The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86.2

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

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The DSM incentive amount related to programs for Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

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The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

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Louisville Gas and Electric Company

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the “Three-Month Commercial Paper Rate” for the immediately preceding twelve-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DCCR = DSM CAPITAL COST RECOVERY

The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

$$DCCR = [(RB)\ (ROR + (ROR - DR)\ (TR / (1 - TR))] + OE$$

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company’s various DSM-related capital investment(s).

CHANGES TO DSMRC

Modifications to components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.
2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA, DCCR, and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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Louisville Gas and Electric Company

P.S.C. Electric No.10, Original Sheet No. 86.4

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RS, RTOD-Energy, RTOD-Demand, and VFD Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employs switches in homes to help reduce the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve-month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

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P.S.C. Electric No. 11, Original Sheet No. 86.4

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
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Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.5

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential Incentives Program

The Residential Incentives Program encourages customers to purchase and install various ENERGY STAR® appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive as noted in the table below.

Category	Item	Incentive
Appliances	Heat Pump Water Heaters (HPWH)	$300 per qualifying item purchased
	Washing Machine	$75 per qualifying item purchased
	Refrigerator	$100 per qualifying item purchased
	Freezer	$50 per qualifying item purchased
	Dishwasher	$50 per qualifying item purchased
Window Film	Window Film	Up to 50% of materials cost only; max of $200 per customer account; product must meet applicable criteria.
HVAC	Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum
	Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus additional $100 per SEER improvement above minimum

Residential Refrigerator Removal Program

The Residential Refrigerator Removal Program is designed to provide removal and recycling of working, inefficient secondary refrigerators and freezers from LG&E customer households. Customers participating in this program will be provided a one-time incentive. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Customer Education and Public Information

This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential Incentives Program

The Residential Incentives Program encourages customers to purchase and install various ENERGY STAR® appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive as noted in the table below.

Category	Item	Incentive
Appliances	Heat Pump Water Heaters (HPWH)	$300 per qualifying item purchased
	Washing Machine	$75 per qualifying item purchased
	Refrigerator	$100 per qualifying item purchased
	Freezer	$50 per qualifying item purchased
	Dishwasher	$50 per qualifying item purchased
Window Film	Window Film	Up to 50% of materials cost only; max of $200 per customer account; product must meet applicable criteria.
HVAC	Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum
	Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus additional $100 per SEER improvement above minimum

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.6

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the RS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, PS, TODS, TODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employs switches or interfaces to customer equipment in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.9.

Commercial Conservation / Commercial Incentives
The Commercial Conservation / Commercial Incentive Program is designed to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for energy-efficiency improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable kW removed. New construction rebates are available on savings over code plus bonus rebates for LEED certification.

- Maximum annual incentive per facility is $50,000
- Customers can receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year
- Applicable for combined Prescriptive, Custom, and New Construction Rebates

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State Regulation and Rates
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Louisville Gas and Electric Company

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the RS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, PS, TODS, TODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employs switches or interfaces to customer equipment in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.9.

Commercial Conservation / Commercial Incentives
The Commercial Conservation / Commercial Incentive Program is designed to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for energy-efficiency improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable kW removed. New construction rebates are available on savings over code plus bonus rebates for LEED certification.

- Maximum annual incentive per facility is $50,000
- Customers can receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year
- Applicable for combined Prescriptive, Custom, and New Construction Rebates

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.7

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Customer Education and Public Information
This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign and an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

School Energy Management Program
The School Energy Management program will facilitate the hiring and retention of qualified, trained energy specialists by public school districts to support facilitation of energy efficiency measures for public and independent schools under KRS 160.325.

Commercial Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the GS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86.7

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Customer Education and Public Information
This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign and an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

School Energy Management Program
The School Energy Management program will facilitate the hiring and retention of qualified, trained energy specialists by public school districts to support facilitation of energy efficiency measures for public and independent schools under KRS 160.325.

Commercial Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the GS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00003 dated November 14, 2014

Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Sheet No. 86.8
Canceling P.S.C. Electric No. 10, Original Sheet No. 86.8

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Current Program Incentive Structures

Residential Load Management / Demand Conservation
Switch Option:

- $5/month bill credit for June, July, August, and September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, and September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.
- If new customer registers by December 31, 2016, then a $25 gift card per air-conditioning unit, heat pump, water heater (40 gallon minimum) and/or swimming pool pump switch installed.
  - o Customers in a tenant-landlord relationship will receive the entire $25 new customer incentive.

Multi-family Option:

- Tenant - $2/month bill credit per customer for June, July, August, and September per air conditioning unit, heat pump, or water heater (40 gallon minimum).
- Entire Complex Enrollment – Property owner receives $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, and September.
- If new customer registers by December 31, 2016, then a $25 gift card per air-conditioning unit or heat pump installed, where:
  - o Customers in a tenant/property owner relationship where the entire complex participates, the property owner will receive a $25 bonus incentive per air conditioning unit, heat pump, or water heater (40 gallon minimum).
  - o Customers in a tenant-landlord relationship where only a portion of the complex participates, the tenant will receive a $25 gift card new customer incentive.

Residential Refrigerator Removal Program

The program provides $50 per working refrigerator or freezer.

DATE OF ISSUE: July 20, 2015

DATE EFFECTIVE: With Service Rendered On
and After August 19, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86.8

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Current Program Incentive Structures

Residential Load Management / Demand Conservation
Switch Option:

- $5/month bill credit for June, July, August, and September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, and September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.
- If new customer registers by December 31, 2016, then a $25 gift card per air-conditioning unit, heat pump, water heater (40 gallon minimum) and/or swimming pool pump switch installed.
  - o Customers in a tenant-landlord relationship will receive the entire $25 new customer incentive.

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- Tenant - $2/month bill credit per customer for June, July, August, and September per air conditioning unit, heat pump, or water heater (40 gallon minimum).
- Entire Complex Enrollment – Property owner receives $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, and September.
- If new customer registers by December 31, 2016, then a $25 gift card per air-conditioning unit or heat pump installed, where:
  - o Customers in a tenant/property owner relationship where the entire complex participates, the property owner will receive a $25 bonus incentive per air conditioning unit, heat pump, or water heater (40 gallon minimum).
  - o Customers in a tenant-landlord relationship where only a portion of the complex participates, the tenant will receive a $25 gift card new customer incentive.

Residential Refrigerator Removal Program

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: With Service Rendered On
and After August 19, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.9

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Commercial Load Management / Demand Conservation

Switch Option

- $5 per month bill credit for June, July, August, and September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50 kW demand reduction per control event.

- $25 per kW for verified load reduction during June, July, August, and September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86.9

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Commercial Load Management / Demand Conservation

Switch Option

- $5 per month bill credit for June, July, August, and September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50 kW demand reduction per control event.

- $25 per kW for verified load reduction during June, July, August, and September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00003 dated November 14, 2014

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Third Revision of Original Sheet No. 86.10
Canceling P.S.C. Electric No. 10, Second Revision of Original Sheet No. 86.10

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00167 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00026 per kWh
DSM Incentive (DSMI)	$ 0.00008 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00156 per kWh
DSM Balance Adjustment (DBA)	$ (0.00011) per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00346 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00094 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00034 per kWh
DSM Incentive (DSMI)	$ 0.00005 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00021 per kWh
DSM Balance Adjustment (DBA)	$ (0.00027) per kWh
Total DSMRC for Rate GS	$ 0.00127 per kWh

Power Service Rate PS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00040 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00013 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00044 per kWh
DSM Balance Adjustment (DBA)	$ (0.00018) per kWh
Total DSMRC for Rate PS	$ 0.00081 per kWh

Time-of-Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, and Retail Transmission Service Rate RTS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00022 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00007 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00005 per kWh
DSM Balance Adjustment (DBA)	$ (0.00025) per kWh
Total DSMRC for Rates TODS, and TODP	$ 0.00010 per kWh

* These charges do not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

DATE OF ISSUE: April 18, 2016

DATE EFFECTIVE: June 30, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00398 dated March 31, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 86.10

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00167 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00026 per kWh
DSM Incentive (DSMI)	$ 0.00008 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00156 per kWh
DSM Balance Adjustment (DBA)	$ (0.00011) per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00346 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00094 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00034 per kWh
DSM Incentive (DSMI)	$ 0.00005 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00021 per kWh
DSM Balance Adjustment (DBA)	$ (0.00027) per kWh
Total DSMRC for Rate GS	$ 0.00127 per kWh

Power Service Rate PS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00040 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00013 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00044 per kWh
DSM Balance Adjustment (DBA)	$ (0.00018) per kWh
Total DSMRC for Rate PS	$ 0.00081 per kWh

Time-of-Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, and Retail Transmission Service Rate RTS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00022 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00007 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00005 per kWh
DSM Balance Adjustment (DBA)	$ (0.00025) per kWh
Total DSMRC for Rates TODS, and TODP	$ 0.00010 per kWh

* These charges do not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: June 30, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00398 dated March 31, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Second Revision of Original Sheet No. 87
Canceling P.S.C. Electric No. 10, First Revision of Original Sheet No. 87

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE.
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS.

RATE
The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS
1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f) EAS is the total proceeds from emission allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

DATE OF ISSUE: August 15, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00027 dated August 8, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 87

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows: **T**

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE.
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; FLS; EVSE; and EVC. **T**

RATE
The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS
1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f) EAS is the total proceeds from emission allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Original Sheet No. 87.1
Canceling P.S.C. Electric No. 10, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

DEFINITIONS (continued)

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

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DATE EFFECTIVE: August 31, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00027 dated August 8, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

DEFINITIONS (continued)

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 31, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00027 dated August 8, 2016

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 88

Adjustment Clause **OSS**
Off-System Sales Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules that are subject to the Fuel Adjustment Clause.

RATE
The monthly OSS Adjustment Factor per kWh delivered under each of the schedules to which this mechanism is applicable shall be calculated in accordance with the following formula:

$$\text{OSS Adjustment Factor} = 0.75 \times [(P(m) / S(m)]$$

Where “P” is the net eligible margins from off-system power sales and “S” is the kWh sales in the current period (m) as defined in 807 KAR 5:056. The OSS Adjustment Factor will be applied as set out below.

1) The monthly OSS Adjustment Factor will be combined with the monthly FAC factor and billed as one.

2) Current expense month (m) shall be the second month preceding the month in which the combined FAC and OSS factor is billed.

3) The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 88

Adjustment Clause **OSS**
Off-System Sales Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules that are subject to the Fuel Adjustment Clause.

RATE
The monthly OSS Adjustment Factor per kWh delivered under each of the schedules to which this mechanism is applicable shall be calculated in accordance with the following formula:

$$\text{OSS Adjustment Factor} = 0.75 \times [(P(m) / S(m)]$$

Where “P” is the net eligible margins from off-system power sales and “S” is the kWh sales in the current period (m) as defined in 807 KAR 5:056. The OSS Adjustment Factor will be applied as set out below.

1) The monthly OSS Adjustment Factor will be combined with the monthly FAC factor and billed as one.

2) Current expense month (m) shall be the second month preceding the month in which the combined FAC and OSS factor is billed.

3) The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 90

Adjustment Clause **FF**
Franchise Fee Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS
Base Year - the twelve-month period ending November 30.
Collection Year - the full calendar year following the Base Year.
Base Year Amount -
1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) License fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE
The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING
1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
2) The franchise charge will appear as a separate line item on the Customer's bill and show the unit of government requiring the franchise.
3) Payment of the collected franchise charges will be made to the governmental franchising body as agreed to in the franchise agreement.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: October 16, 2003

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 90

Adjustment Clause **FF**
Franchise Fee Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS
Base Year - the twelve-month period ending November 30.
Collection Year - the full calendar year following the Base Year.
Base Year Amount -
1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) License fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE
The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING
1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: October 16, 2003

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 90.1

Adjustment Clause **FF**
Franchise Fee Rider

TERM OF CONTRACT

As agreed to in the franchise agreement. In the event such franchise agreement should lapse but payment of franchise fees, other local taxes, or permitting fees paid by Company by ordinance, franchise, or other governmental directive should continue, collection shall continue under this tariff.

TERMS AND CONDITIONS

Service will be furnished in accordance with the provisions of the franchise agreement in so far as those provisions do not conflict with the Terms and Conditions applicable to Company approved by and under the direction of the Kentucky Public Service Commission.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: October 16, 2003

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 90.1

Adjustment Clause **FF**
Franchise Fee Rider

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: October 16, 2003

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 91

Adjustment Clause **ST**
School Tax

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE
The utility gross receipts license tax authorized under state law.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 91

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 92

Adjustment Clause **HEA**

Home Energy Assistance Program

APPLICABLE

In all territory served.

AVAILABILITY

To all residential customers.

RATE

$0.25 per meter per month.

BILLING

The HEA charge shall be shown as a separate item on customer bills.

PURPOSE

Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 92

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 95

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 95

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- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service, unless any rate or rider under which you take service explicitly states otherwise. **T**
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions, which shall constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR

The United Nations Convention on Contracts for the International Sale of Goods is specifically disclaimed and excluded and will not apply to or govern agreements between customers and Company.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which electric service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions in each rate schedule, and which shall constitute a part of all applications and contracts for service. T T T

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CUSTOMER GENERATION T

All existing and future installations of equipment for the purpose of electric generation that is intended to run in parallel with utility service, regardless of the length of parallel operation, shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 96.1

TERMS AND CONDITIONS

General

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied electric service.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 96.1

TERMS AND CONDITIONS

General

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 97

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render electric service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

TRANSFER OF APPLICATION

Applications for electric service are not transferable and new occupants of premises will be required to make application for service before commencing the use of electricity. Customers who have been receiving electric service shall notify Company when discontinuance of service is desired, and shall pay for all electric service furnished until such notice has been given and final meter readings made by Company.

CONTRACTED DEMANDS

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company's sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on Company's system for determining Contract Demand minimum.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which customer desires to receive service.

Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 97

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written, in-person, electronic, or oral application or contract, properly executed, will be required before Company is obligated to render electric service. Company may require any party applying for service to provide some or all of the following information for the party desiring service: full legal name, address, full Social Security Number or other taxpayer identification number, date of birth (if applicable), relationship of the applying party to the party desiring service, and any other information Company deems necessary for legal, business, or debt-collection purposes. Company shall have the right to reject for valid reasons any such application or contract, including the applying party's refusal to provide requested information. T

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

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If Company or Customer terminates Customer's service under a rate schedule that contains demand charges and Customer subsequently applies to Company to reestablish service to the same premise or facility, Company must determine monthly billing demand for the reestablished service as though Customer had continuously taken service from the time of service termination through the reestablishing of service to Customer. For the purpose of determining the monthly billing demand described in the preceding sentence, the demand to be used for the period during which Customer did not take service from Company shall be the actually recorded demand, if any, for the premise or facility during that period. The preceding two sentences will not apply if Company determines, in its sole discretion, that material changes to Customer's facilities, processes, or practices justify establishing a new Contract Demand for the reestablished service. T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 97.1

TERMS AND CONDITIONS

Customer Responsibilities

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that customers will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

CUSTOMER'S EQUIPMENT AND INSTALLATION

Customer shall furnish, install and maintain at Customer's expense all electrical apparatus and wiring to connect with Company's service drop or service line. All such apparatus and wiring shall be installed and maintained in conformity with applicable statutes, laws or ordinances and with the rules and regulations of the constituted authorities having jurisdiction. Customer shall not install wiring or connect and use any motor or other electricity-using device which in the opinion of Company is detrimental to its electric system or to the service of other customers of Company. Company assumes no responsibility whatsoever for the condition of Customer's electrical wiring, apparatus, or appliances, nor for the maintenance or removal of any portion thereof.

In the event Customer builds or extends its own transmission or distribution system over property Customer owns, controls, or has rights to, and said system extends or may extend into the service territory of another utility company, Customer will notify Company of their intention in advance of the commencement of construction.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of electric service or for the purpose of turning on and shutting off the supply of electricity when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 97.1

TERMS AND CONDITIONS

Customer Responsibilities

OPTIONAL RATES T

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which customer desires to receive service.

Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

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Customer shall furnish, install and maintain at Customer's expense all electrical apparatus and wiring to connect with Company's service drop or service line. All such apparatus and wiring shall be installed and maintained in conformity with applicable statutes, laws or ordinances and with the rules and regulations of the constituted authorities having jurisdiction. Customer shall not install wiring or connect and use any motor or other electricity-using device which in the opinion of Company is detrimental to its electric system or to the service of other customers of Company. Company assumes no responsibility whatsoever for the condition of Customer's electrical wiring, apparatus, or appliances, nor for the maintenance or removal of any portion thereof.

In the event Customer builds or extends its own transmission or distribution system over property Customer owns, controls, or has rights to, and said system extends or may extend into the service territory of another utility company, Customer will notify Company of their intention in advance of the commencement of construction.

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Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No.10, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to its customers at or near unity power factor.

Company expects any customer to use apparatus which shall result in a power factor near unity However, Company will permit the use of apparatus which shall result, during normal operation, in a power factor not lower than 90 percent either lagging or leading.

Where Customer's power factor is less than 90 percent, Company reserves the right to require the customer to furnish, at Customer's own expense, suitable corrective equipment to maintain a power factor of 90 percent or higher.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Except in cases where Customer has contracted with Company for reserve or auxiliary service, no other electric light or power service will be used by Customer on the same installation in conjunction with Company's service, either by means of a throw-over switch or any other connection.

LIABILITY

Customer assumes all responsibility for the electric service upon Customer's premises at and from the point of delivery of electricity and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service connections, transformers, meters, and appurtenances supplied by Company for the rendition of electric service to its customers have a definite capacity which may not be exceeded without damage. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, transformers, or other equipment of Company caused by such material increase in the Customer's connected load. Should Customer make a permanent change in the operation of electrical equipment that materially reduces the maximum load required by Customer, Company may reduce Customer's contract capacity.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

ACCESS TO PREMISES AND EQUIPMENT **T**

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of electric service or for the purpose of turning on and shutting off the supply of electricity when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

POWER FACTOR

Company installs facilities to supply power to its customers at or near unity power factor.

Company expects any customer to use apparatus which shall result in a power factor near unity However, Company will permit the use of apparatus which shall result, during normal operation, in a power factor not lower than 90 percent either lagging or leading.

Where Customer's power factor is less than 90 percent, Company reserves the right to require the customer to furnish, at Customer's own expense, suitable corrective equipment to maintain a power factor of 90 percent or higher.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Except in cases where Customer has contracted with Company for reserve or auxiliary service, no other electric light or power service will be used by Customer on the same installation in conjunction with Company's service, either by means of a throw-over switch or any other connection.

LIABILITY

Customer assumes all responsibility for the electric service upon Customer's premises at and from the point of delivery of electricity and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines, Customer shall obtain from the property owner or owners the necessary consent to the installation and maintenance in said premises and in or about such intervening property of
all such wiring or other customer-owned electrical equipment as may be necessary or convenient for the supply of electric service to customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

The construction of electric facilities to provide service to a number of customers in a manner consistent with good engineering practice and the least public inconvenience sometimes requires that certain wires, guys, poles, or other appurtenances on a customer's premises be used to supply service to neighboring customers. Accordingly, each customer taking Company's electric service shall grant to Company such rights on or across his or her premises as may be necessary to furnish service to neighboring premises, such rights to be exercised by Company in a reasonable manner and with due regard for the convenience of the customer.

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

CHANGES IN SERVICE

Where Customer is receiving service and desires relocation or change in facilities not supported by additional load, Customer is responsible for the cost of the relocation or change in facilities through a Non-Refundable Advance.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD **T**

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

POINT OF DELIVERY OF ELECTRICITY

The point of delivery of electrical energy supplied by Company shall be at the point, as designated by Company, where Company's facilities are connected with the facilities of Customer, irrespective of the location of the meter

EXTENSION OF SERVICE

The main transmission lines of Company, or branches thereof, will be extended to such points as provide sufficient load to justify such extensions or in lieu of sufficient load, Company may require such definite and written guarantees from a customer, or group of customers, in addition to any minimum payments required by the Tariff as may be necessary. This requirement may also be made covering the repayment, within a reasonable time, of the cost of tapping such existing lines for light or power service or both.

COMPANY'S EQUIPMENT AND INSTALLATION

Company will furnish, install, and maintain at its expense the necessary overhead service drop or service line required to deliver electricity at the voltage contracted for, to Customer's electric facilities.

Company will furnish, install, and maintain at its expense the necessary meter or meters. (The term meter as used here and elsewhere in these rules and regulations shall be considered to include all associated instruments and devices, such as current and potential transformers installed for the purpose of measuring deliveries of electricity to the customer.) Suitable provision for Company's meter, including an adequate protective enclosure for the same if required, shall be made by Customer. Title to the meter shall remain with Company, with the right to install, operate, maintain, and remove same. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage, or tamper with the same. Customer shall execute such reasonable form of easement agreement as may be required by Company.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters.
Company has the right to install any meter or meters it deems in its sole discretion to be **T**
necessary or prudent to serve any customer, including without limitation a digital, automated **T**
meter reading, automated metering infrastructure, or advanced metering systems meter or **T**
meters. When service is supplied by Company at more than one delivery point on the same **T**
premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective electricity requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply service continuously and without interruption but does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay, or failure of electric service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of electricity delivered to the point of connection of Company's and Customer's facilities, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of Customer or of third persons resulting from the presence, use or abuse of electricity on Customer's premises or resulting from defects in or accidents to any of customer's wiring, equipment, apparatus, or appliances, or resulting from any cause whatsoever other than the negligence of Company

LIABILITY

In no event shall Company have any liability to Customer or any other party affected by the electrical service to Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to Customer or any other party. In the event that Customer's use of Company's service causes damage to Company's property or injuries to persons, Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

FIRM SERVICE

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective electricity requirements.

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LIABILITY

In no event shall Company have any liability to Customer or any other party affected by the electrical service to Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to Customer or any other party. In the event that Customer's use of Company's service causes damage to Company's property or injuries to persons, Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedule herein, will be 60 cycle, alternating current delivered from Company's various load centers and distribution lines at typical nominal voltages and phases, as available in a given location, as follows:

SECONDARY VOLTAGES

Residential Service -

Single phase 120/240 volts three-wire service or 120/208Y volts three-wire service where network system is available.

Non-Residential Service -

1) Single phase 120/240 volts three-wire service or 120/208Y three-wire service where network system is available.
2) Three phase 240 volts three-wire, 480 volts three-wire service, 120/208Y volts four-wire service, or 277/480Y volts four-wire service.

PRIMARY VOLTAGES

According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 volts, or 34,500 volts.

TRANSMISSION VOLTAGES

According to location, 69,000 volts, 138,000 volts, or 345,000 volts.

The voltage available to any individual customer shall depend upon the voltage of Company's lines serving the area in which such customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of the Company, two-wire service is restricted to those customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, a customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.
   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to Customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b) The available voltage shall be the voltage on that distribution or transmission line which the Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 99

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 100

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

Residential electric service is available for uses customarily associated with residential occupation, including lighting, cooking, heating, cooling, refrigeration, household appliances, and other domestic purposes.

1. **DEFINITION OF RESIDENTIAL RATE** - Residential rates are based on service to single family units served through a single meter. Such service may include incidental usage of electricity for home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is practiced by Customer in his residence. Service to both a single family unit and a detached structure may both be served through a single meter, regardless of the meter location, and qualify for the residential service provided the consumption in the non-residential portion of the detached structure is incidental.

2. **DEFINITION OF SINGLE FAMILY UNIT** - A single family unit is a structure or part of a structure used or intended to be used as a home, residence, or sleeping place by one or more persons maintaining a common household. Residential service is not available to transient multi-family structures including, but not limited to, hotels, motels, studio apartments, college dormitories, or any structure without a permanent foundation or attached to sanitation facilities. Fraternity or sorority organizations associated with educational institutions may be classified as residential and billed at the residential rate.

3. **DETACHED STRUCTURES** - If Customer has detached structures that are located at such distance from Customer's residence as to make it impracticable to supply service through customer's residential meter, the separate meter required to measure service to the detached structures will be considered a separate service and billed as a separate customer.

4. **POWER REQUIREMENT** - Single-phase power service used for domestic purposes will be permitted under Residential Rate RS when measured through the residential meter subject to the conditions set forth below:

   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 100

TERMS AND CONDITIONS

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   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

(c) In the case of multi-motored devices arranged for sequential starting of the motors, the above rules are considered to apply to the locked-rotor currents of the individual motors; if arranged for simultaneous starting of the motors, the rules apply to the sum of the locked-rotor currents of all motors so started.

(d) Any motor or motors served through a separate meter will be billed as a separate customer.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

TERMS AND CONDITIONS

BILLING

METER READINGS AND BILLS

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customer meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. Provided, however, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of rendition thereof. If full payment is not received by the due date of the bill, a late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy

Louisville Gas and Electric Company

TERMS AND CONDITIONS

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METER READINGS AND BILLS

As used in the entirety of this Tariff, “meter reading” and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a “meter reading.”

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customer meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

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Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of rendition thereof. If full payment is not received by the due date of the bill, a late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy

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TERMS AND CONDITIONS

BILLING

assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

CUSTOMER RATE ASSIGNMENT

If Customer takes service under a rate schedule the eligibility for which contains a minimum or maximum demand parameter (or both), Company will review Customer's demand and usage data at least once annually to determine the rate schedule under which Customer will take service until the next review and rate determination. Company will also conduct such a review and determination upon Customer's request. Company shall not be obligated to change Customer's rate determination based upon detection of a substantial deviation of Customer's demand or usage if, after consultation with Customer, Company determines in its sole discretion that such deviation is not indicative of Customer's likely long-term demand. Similarly, Company may assign Customer to a rate schedule for which Customer would not be eligible based solely on Customer's historical demand or usage, but Company may do so only as part of a review and rate determination that involves consulting with Customer about Customer's likely future demand, as well as Customer's special contract demand, if applicable.

Any such review and rate determination shall be deemed conclusively to be the correct rate determination for Customer for all purposes and for all periods until Company conducts the next such review and determination for Customer. Therefore, Company shall not be liable for any refunds to Customer based upon Customer's rate assignment, and Company shall not seek to back-bill Customer based upon Customer's rate assignment, for any periods between and including such reviews and determinations unless, and only in the event that, a particular review and rate determination are shown to have been materially erroneous at the time they were conducted, in which case Company may be liable for a refund, or may back-bill Customer, only for the period from the erroneous review and determination to the present or the next non-erroneous review and determination, whichever is shorter.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 101.1

TERMS AND CONDITIONS

BILLING

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If Customer takes service under a rate schedule the eligibility for which contains a minimum or maximum demand parameter (or both), Company will review Customer's demand and usage data at least once annually to determine the rate schedule under which Customer will take service until the next review and rate determination. Company will also conduct such a review and determination upon Customer's request. Company shall not be obligated to change Customer's rate determination based upon detection of a substantial deviation of Customer's demand or usage if, after consultation with Customer, Company determines in its sole discretion that such deviation is not indicative of Customer's likely long-term demand. Similarly, Company may assign Customer to a rate schedule for which Customer would not be eligible based solely on Customer's historical demand or usage, but Company may do so only as part of a review and rate determination that involves consulting with Customer about Customer's likely future demand, as well as Customer's special contract demand, if applicable.

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 101.2

TERMS AND CONDITIONS

BILLING

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is then taking service under such a rate schedule, Company will not change Customer's rate assignment; it will remain Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is not then taking service under such a rate schedule, Company will (1) provide reasonable notice to Customer of the options available and (2) assign Customer to the rate schedule Company reasonably believes will be most financially beneficial to Customer based on Customer's historical demand and usage, which assignment Company will change upon Customer's request to take service under another rate schedule for which Customer is eligible. Company shall have no refund obligation or bear any other liability or responsibility for its initial assignment of Customer to a rate for which Customer is eligible; it is at all times Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

Nothing in this section is intended to curtail or diminish Customer's responsibility to choose among optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1. Likewise, except as explicitly stated in the paragraph above, nothing in this section creates an obligation or responsibility for Company to assign Customer to a particular rate schedule for which Customer is eligible if Customer is eligible for more than one rate schedule.

CUSTOMER RATE MIGRATION

A change from one rate to another will be effective with the first full billing period following a customer's request for such change, or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

CLASSIFICATION OF CUSTOMERS

For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes which create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32 and 33. All other non-residential customers will be defined as "commercial."

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 101.2

TERMS AND CONDITIONS

BILLING

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 101.3

TERMS AND CONDITIONS

BILLING

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual customer consumption, Company will monitor the usage of each customer at least once quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1). Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

RESALE OF ELECTRIC ENERGY

Electric energy furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such energy to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

MINIMUM CHARGE

Without limiting the foregoing, the Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer's ability or interest in operating Customer's facility, including but without limitation any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company's ability to serve customer.

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DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 101.3

TERMS AND CONDITIONS

BILLING

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 102

TERMS AND CONDITIONS

DEPOSITS

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 8 except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service
3) Company may offer residential or general service customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first six (6) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service Rate RS - Sheet No. 5, Residential Time-of-Day Energy Service Rate RTOD-Energy – Sheet No. 6, and Residential Time-of-Day Demand Service Rate RTOD-Demand – Sheet No. 7.
2) The deposit for a residential customer is in the amount of $160.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2). For combination gas and electric customers, the total deposit will be $260.00.
3) Company shall retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 102

TERMS AND CONDITIONS

DEPOSITS

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   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 102.1

TERMS AND CONDITIONS

DEPOSITS

RESIDENTIAL (Continued)

5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

GENERAL SERVICE

1) General service customers are those customers served under General Service Rate GS, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $240.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2).The deposit for a General Service customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service energy usage is no more than 300 kWh per month.
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d)(1).
2) For customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
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DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 102.1

TERMS AND CONDITIONS

DEPOSITS

RESIDENTIAL (Continued)

5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer served under Residential Service Rate RS or any general service customer served under General Service Rate GS. If a residential customer, who is currently served under Residential Service Rate RS and is currently enrolled in the Budget Payment Plan, elects to take service under Residential Time-of-Day Energy Service Rate RTOD-Energy or Residential Time-of-Day Demand Service Rate RTOD-Demand, such customer would be removed from the Budget Payment Plan and restored to regular billing.

Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company, and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove Customer from the plan, restore the Customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts Customer from the provisions of these terms and conditions.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 103

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Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer served under Residential Service Rate RS or any general service customer served under General Service Rate GS. If a residential customer, who is currently served under Residential Service Rate RS and is currently enrolled in the Budget Payment Plan, elects to take service under Residential Time-of-Day Energy Service Rate RTOD-Energy or Residential Time-of-Day Demand Service Rate RTOD-Demand, such customer would be removed from the Budget Payment Plan and restored to regular billing.

Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company, and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove Customer from the plan, restore the Customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts Customer from the provisions of these terms and conditions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Original Sheet No. 104
Canceling P.S.C. Electric No. 10, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed 4/21/16 for Account # 3000-3333-3333

AMOUNT DUE	DUE DATE
$113.68	5/26/16

BILLING SUMMARY

Previous Balance	194.39
Payment(s) Received	-194.39
Balance as of 4/28/16	**$0.00**
Current Electric Charges	113.68
Total Current Charges as of 4/28/16	**$113.68**
Total Amount Due	**$113.68**

Account Name: JOHN SMITH
Service Address: 100 Towne Creek Rd, LOUISVILLE KY

Online Payments: lge-ku.com
Telephone Payments: (502) 589-1444, press 1-2-3, 24 hours a day, $2.25 fee
Customer Service: (502) 589-1444, M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway, Louisville, KY 40202, M-F, 8am-5pm ET

Next read will occur 5/27/16 - 5/29/16 (Meter Read Portion 19)

CURRENT USAGE

ELECTRIC

Meter Reading Information	Meter # 500000
Actual (R) kWh Reading on 4/28/16	26762
Previous (R) kWh Reading on 3/30/16	25669
Current kWh Usage	1093
Meter Multiplier	1
Metered kWh Usage	**1093**

CURRENT CHARGES

ELECTRIC Rate: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 1,093 kWh)	88.27
Electric DSM ($0.00520 x 1,093 kWh)	5.68
Electric Fuel Adjustment ($0.00224 x 1,093 kWh)	2.45
Environmental Surcharge (5.860% x $107.15)	6.28
Home Energy Assistance Fund Charge	0.25
Total Charges	**$113.68**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due 5/26/16	$113.68
After Due Date, Pay this Amount:	$117.09
Winterhelp Donation:	
Total Amount Enclosed:	

Account # 3000-3333-3333
Service Address: 100 Towne Creek Rd

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

#926190003 3#
JOHN SMITH
100 TOWNE CREEK RD
LOUISVILLE, KY 40243-1000

0103000333333330000000117090000001136800000000000024

DATE OF ISSUE: March 30, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed 4/21/16 for Account # 3000-3333-3333

AMOUNT DUE	DUE DATE
$113.68	5/26/16

BILLING SUMMARY

Previous Balance	194.39
Payment(s) Received	-194.39
Balance as of 4/28/16	**$0.00**
Current Electric Charges	113.68
Total Current Charges as of 4/28/16	**$113.68**
Total Amount Due	**$113.68**

Account Name: JOHN SMITH
Service Address: 100 Towne Creek Rd, LOUISVILLE KY

Online Payments: lge-ku.com
Telephone Payments: (502) 589-1444, press 1-2-3, 24 hours a day, $2.25 fee
Customer Service: (502) 589-1444, M-F, 7am-7pm ET
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Next read will occur 5/27/16 - 5/29/16 (Meter Read Portion 19)

CURRENT USAGE

ELECTRIC

Meter Reading Information	Meter # 500000
Actual (R) kWh Reading on 4/28/16	26762
Previous (R) kWh Reading on 3/30/16	25669
Current kWh Usage	1093
Meter Multiplier	1
Metered kWh Usage	**1093**

CURRENT CHARGES

ELECTRIC Rate: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 1,093 kWh)	88.27
Electric DSM ($0.00520 x 1,093 kWh)	5.68
Electric Fuel Adjustment ($0.00224 x 1,093 kWh)	2.45
Environmental Surcharge (5.860% x $107.15)	6.28
Home Energy Assistance Fund Charge	0.25
Total Charges	**$113.68**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due 5/26/16	$113.68
After Due Date, Pay this Amount:	$117.09
Winterhelp Donation:	
Total Amount Enclosed:	

Account # 3000-3333-3333
Service Address: 100 Towne Creek Rd

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

#926190003 3#
JOHN SMITH
100 TOWNE CREEK RD
LOUISVILLE, KY 40243-1000

0103000333333330000000117090000001136800000000000024

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Original Sheet No. 104.1
Canceling P.S.C. Electric No. 10, Original Sheet No. 104.1

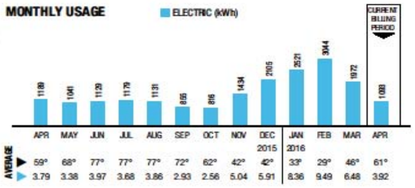
TERMS AND CONDITIONS
Bill Format

Page 2

Account # **3000-3333-3333**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**61°**	**60°**
Number of Days Billed	29	31
Avg. Electric Charges per Day	**$3.92**	**$3.79**
Avg. Electric Usage per Day (kWh)	37.69	38.35



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.41

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY
MRU1 9833024, G000000
P194.39
PF:Y eB:P

DATE OF ISSUE: March 30, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 104.1

TERMS AND CONDITIONS

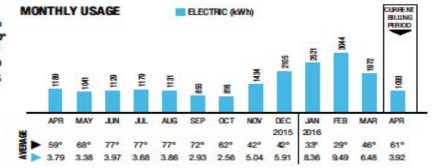
Bill Format

Page 2

Account # **3000-3333-3333**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**61°**	**60°**
Number of Days Billed	29	31
Avg. Electric Charges per Day	**$3.92**	**$3.79**
Avg. Electric Usage per Day (kWh)	37.69	38.35



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.41

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY
MRU1 9833024, G000000
P194.39
PF:Y eB:P

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Original Sheet No. 104.2
Canceling P.S.C. Electric No. 10, Original Sheet No. 104.2

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed 4/8/16 for Account # 3000-5555-5555

AMOUNT DUE	DUE DATE
$107.65	5/1/16

Account Name:	JOHN SMITH
Service Address:	100 Cassidy Ln LOUISVILLE KY
Online Payments:	lge-ku.com
Telephone Payments:	502-589-1444, press 1-2-3 24 hours a day; $2.25 fee
Customer Service:	502-589-1444 M-F, 7am-7pm ET
Walk-in Center:	820 W. Broadway Louisville, KY 40202 M-F, 8am-5pm ET

Next read will occur 5/4/16 - 5/6/16 (Meter Read Portion 03)

BILLING SUMMARY

Previous Balance	185.14
Payment(s) Received	-185.14
Balance as of 4/7/16	**$0.00**
Current Electric Charges	54.03
Current Gas Charges	53.62
Total Current Charges as of 4/7/16	**$107.65**
Total Amount Due	**$107.65**

CURRENT USAGE

ELECTRIC

Meter Reading Information	**Meter # 700000**
Actual (R) kWh Reading on 4/7/16	58526
Previous (R) kWh Reading on 3/9/16	58072
Current kWh Usage	454
Meter Multiplier	1
Metered kWh Usage	**454**

GAS

Meter Reading Information	**Meter # 600000**
Actual (R) ccf Reading on 4/7/16	2704
Previous (R) ccf Reading on 3/9/16	2658
Current ccf Usage	46
Meter Multiplier	1
Metered ccf Usage	**46**

CURRENT CHARGES

ELECTRIC — **Rate:** Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 454 kWh)	36.67
Electric DSM ($0.00520 x 454 kWh)	2.36
Electric Fuel Adjustment ($0.00224 x 454 kWh)	1.02
Environmental Surcharge (5.860% x $50.80)	2.98
Home Energy Assistance Fund Charge	0.25
Total Charges	**$54.03**

GAS — **Rate:** Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 46 ccf)	12.15
Gas Supply Component ($0.49951 x 46 ccf)	22.98
Weather Normalization Adjustment ($0.26419 x 6.093 ccf)	1.61
Gas DSM ($0.01311 x 46 ccf)	0.60
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$53.62**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By 5/1/16	$107.65
After Due Date, Pay This Amount:	**$110.91**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # 3000-5555-5555
Service Address: 100 Cassidy Ln

#926190005 1#

JOHN SMITH
100 CASSIDY LN
LOUISVILLE, KY 40229-1000

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

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DATE OF ISSUE: March 30, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 104.2

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed 4/8/16 for Account # 3000-5555-5555

AMOUNT DUE	DUE DATE
$107.65	5/1/16

Account Name:	JOHN SMITH
Service Address:	100 Cassidy Ln LOUISVILLE KY
Online Payments:	lge-ku.com
Telephone Payments:	502-589-1444, press 1-2-3 24 hours a day; $2.25 fee
Customer Service:	502-589-1444 M-F, 7am-7pm ET
Walk-in Center:	820 W. Broadway Louisville, KY 40202 M-F, 8am-5pm ET

Next read will occur 5/4/16 - 5/6/16 (Meter Read Portion 03)

BILLING SUMMARY

Previous Balance	185.14
Payment(s) Received	-185.14
Balance as of 4/7/16	**$0.00**
Current Electric Charges	54.03
Current Gas Charges	53.62
Total Current Charges as of 4/7/16	**$107.65**
Total Amount Due	**$107.65**

CURRENT USAGE

ELECTRIC

Meter Reading Information	**Meter # 700000**
Actual (R) kWh Reading on 4/7/16	58526
Previous (R) kWh Reading on 3/9/16	58072
Current kWh Usage	454
Meter Multiplier	1
Metered kWh Usage	**454**

GAS

Meter Reading Information	**Meter # 600000**
Actual (R) ccf Reading on 4/7/16	2704
Previous (R) ccf Reading on 3/9/16	2658
Current ccf Usage	46
Meter Multiplier	1
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CURRENT CHARGES

ELECTRIC — **Rate:** Residential Electric Service

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Home Energy Assistance Fund Charge	0.25
Total Charges	**$53.62**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By 5/1/16	$107.65
After Due Date, Pay This Amount:	**$110.91**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # 3000-5555-5555
Service Address: 100 Cassidy Ln

#926190005 1#

JOHN SMITH
100 CASSIDY LN
LOUISVILLE, KY 40229-1000

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

0103000555555500000000111850000001085900000000000023

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

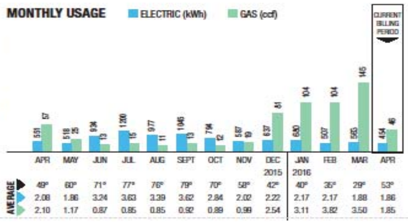
P.S.C. Electric No. 10, First Revision of Original Sheet No. 104.3
Canceling P.S.C. Electric No. 10, Original Sheet No. 104.3

TERMS AND CONDITIONS
Bill Format

Page 2 | Account # **3000-5555-5555**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**53°**	**49°**
Number of Days Billed	29	29
Avg. Electric Charges per Day	**$1.86**	**$2.08**
Avg. Gas Charges per Day	**$1.85**	**$2.10**
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.26

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: March 30, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 104.3

TERMS AND CONDITIONS
Bill Format

Page 2 | Account # **3000-5555-5555**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**53°**	**49°**
Number of Days Billed	29	29
Avg. Electric Charges per Day	**$1.86**	**$2.08**
Avg. Gas Charges per Day	**$1.85**	**$2.10**
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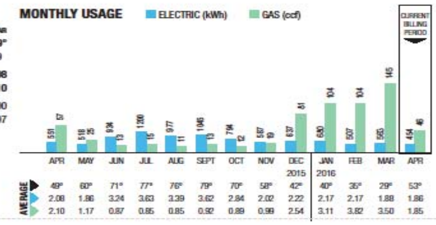
Avg. Gas Usage per Day (ccf)	1.59	1.97



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.26

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and RatesLouisville, Kentucky
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

B. When a dangerous condition is found to exist on the customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify the customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred final bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

B. When a dangerous condition is found to exist on the customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify the customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred final bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

TERMS AND CONDITIONS

Discontinuance of Service

15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications.

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where the Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

TERMS AND CONDITIONS

Discontinuance of Service

lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications. **T**

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where the Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service.

T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 105.2

TERMS AND CONDITIONS

Discontinuance of Service

use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 105.2

TERMS AND CONDITIONS

Discontinuance of Service

Company shall not be required to restore service until Customer has complied with all rules of **T**
Company and regulations of the Commission and Company has been reimbursed for the estimated
amount of the service rendered, and assessment of the charges under the Unauthorized Reconnect **T**
Charge provision of Special Charges incurred by reason of the fraudulent use. **T**

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 106

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY

In all territory served by where Company does not have existing facilities to meet Customer's electric service needs.

B. DEFINITIONS

1) "Company" shall mean Louisville Gas and Electric Company.
2) "Customer" shall mean the applicant for service. When more than one electric service is requested by an applicant on the same extension, such request shall be considered one customer under this plan when the additional service request(s) is only for incidental or minor convenience loads or when the applicant for service is the developer of a subdivision.
3) "Line Extension" shall mean the single phase facilities required to serve Customer by the shortest route most convenient to Company from the nearest existing adequate Company facilities to Customer's delivery point, approved by Company, and excluding transformers, service drop, and meters, if required and normally provided to like customers.
4) "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one year and where the intended use is not seasonal, intermittent, or speculative in nature.
5) "Commission" shall mean the Public Service Commission of Kentucky.

C. GENERAL

1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 106

TERMS AND CONDITIONS

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 106.1

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

5) Customer must agree in writing to take service when the extension is completed and have Customer's building or other permanent facility wired and ready for connection.
6) Nothing herein shall be construed as preventing Company from making electric line extensions under more favorable terms than herein prescribed provided the potential revenue is of such amount and permanency as to warrant such terms and render economically feasible the capital expenditure involved and provided such extensions are made to other customers under similar conditions.
7) Company may require a non-refundable deposit in cases where Customer does not have a real need or in cases where the estimated revenue does not justify the investment.
8) The Company shall not be obligated to extend its lines in cases where such extensions, in the good judgment of Company, would be infeasible, impractical, or contrary to good engineering or operating practice, unless otherwise ordered by Commission.

D. NORMAL LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25kVA and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ 1 above.

E. OTHER LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten (10) year refund period ends.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 106.1

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 106.2

TERMS AND CONDITIONS

Line Extension Plan

E. OTHER LINE EXTENSIONS (continued)

5) Where Customer requires poly-phase service or transformer capacity above 25kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

F. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS

1) In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and through a subdivision may be required by Company to deposit the total cost of the extension.
2) Each year for ten (10) years Company shall refund to Customer, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

G. MOBILE HOME LINE EXTENSIONS

1) Company will make line extensions for service to mobile homes in accordance with 807 KAR 5:041, Section 12, and Commission's Orders.
2) Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home.
3) Company shall provide to Customer requesting permanent service for a mobile home a line extension in excess of 300 feet and up to 1,000 feet but Company may require the total cost of the footage in excess of 300 feet, based on the average cost per foot of the total extension, be deposited with Company by Customer. Beyond 1,000 feet the policies set forth in OTHER LINE EXTENSIONS shall apply.
4) Each year for four (4) years Company shall refund to Customer equal amounts of the deposit for the extension from 300 feet to 1,000 feet.
5) If service is disconnected for sixty (60) days, if the original mobile home is removed and not replaced by another mobile home or a permanent structure in sixty (60) days, the remainder of the deposit is forfeited.
6) No refund will be made except to the original customer.

H. UNDERGROUND LINE EXTENSIONS

General

1) Company will make underground line extensions for service to new residential customers and subdivisions in accordance with 807 KAR 5:041, Section 21.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 106.2

TERMS AND CONDITIONS

Line Extension Plan

E. OTHER LINE EXTENSIONS (continued)

5) Where Customer requires poly-phase service or transformer capacity above 25kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 106.3

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

General (continued

2) In order that Company may make timely provision for materials, and supplies, Company may require Customer to execute a contract for an underground extension under these Terms and Conditions with Company at least six (6) months prior to the anticipated date service is needed and Company may require Customer to deposit with Company at least 10% of any amounts due under the contract at the time of execution. Customer shall deposit the balance of any amounts due under the contract with Company prior to ordering materials or commencement of actual construction by Company of facilities covered by the contract.
3) Customer shall give Company at least 120 days written notice prior to the anticipated date service is needed and Company will undertake to complete installation of its facilities at least thirty (30) days prior to that date. However, nothing herein shall be interpreted to require Company to extend service to portions of subdivisions not under active development.
4) At Company's discretion, Customer may perform a work contribution, to Company's specifications, including but not limited to conduit, setting pads, or any required trenching and backfilling, and Company shall credit amounts due from Customer for underground service by Company's estimated cost for such work contribution.
5) Customer will provide, own, operate and maintain all electric facilities on Customer's side of the point of delivery including the service and with the exception of Company's meter.
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company.
7) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
8) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.
9) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

1) Within the City of Louisville underground district or in those cases where Company's engineering or operating convenience requires the construction of an underground extension to an individual premise, the excess of the cost of an underground extension over that of an overhead extension will be at no cost.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 106.3

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

General (continued

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, First Revision of Original Sheet No. 106.4
Canceling P.S.C. Electric No. 10, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
Individual Premises (continued)

2) In cases other than those specified in 1) above, where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

Medium Density Subdivisions

1) A medium density residential subdivision is defined as containing ten or more lots for the construction of new residential buildings each designed for less than five (5)-family occupancy.
2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount determined by a unit charge of $6.77 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be the Company's full estimate cost of construction. Where Customer is required to deposit with the Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $22.50 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
4) Each year for ten (10) years Company shall refund to Customer an amount determined as follows:
   a. Where customer is required to provide trenching and backfilling, a refund of $5,000 for each customer connected during that year.
   b. Where customer is required to provide a non-refundable advance, 500 times the difference in the unit charge advance amount in 3) and the non-refundable unit charge advance in 2) for each customer connected during that year.
5) In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

High Density Subdivisions

1) A high density residential subdivision is defined as building complexes consisting of two or more buildings each not more than three stories above grade and each designed for five (5) or more family occupancy.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
Individual Premises (continued)

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: December 31, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 106.5

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

High Density Subdivisions (continued)

2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Other Underground Subdivisions

In cases where a particular residential subdivision does not meet the conditions provided for above, Customer requests and Company agrees to supply underground service, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

I. SPECIAL CASES

1) Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlines in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify the Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment.
2) Each year for ten (10) years, Company shall refund to Customer, an amount calculated by:
   a. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric demand billing of the monthly electric billing for that year of any customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company
   b. times the refundable amount divided by the estimated total ten-year base rate electric demand billing required to justify the investment.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 106.5

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

High Density Subdivisions (continued)

2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Other Underground Subdivisions

In cases where a particular residential subdivision does not meet the conditions provided for above, Customer requests and Company agrees to supply underground service, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

I. SPECIAL CASES

1) Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlines in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify the Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment.
2) Each year for ten (10) years, Company shall refund to Customer, an amount calculated by:
   a. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric demand billing of the monthly electric billing for that year of any customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company
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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Louisville Gas and Electric Company ("Company") system in the event of a capacity shortage and to restore service following an outage. Notwithstanding any provisions of these Energy Curtailment and Service Restoration Procedures, Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law.

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

For the purpose of these procedures, the following Priority Levels have been established:

I. Essential Health and Safety Uses -- to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use

A. "Hospitals", which shall be limited to institutions providing medical care to patients.

B. "Life Support Equipment", which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

C. "Police Stations and Government Detention Institutions", which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 107

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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To provide procedures for reducing the consumption of electric energy on the Louisville Gas and Electric Company ("Company") system in the event of a capacity shortage and to restore service following an outage. Notwithstanding any provisions of these Energy Curtailment and Service Restoration Procedures, Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107.1

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

G. “Transportation and Defense-related Services”, which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential street, highway and signal-lighting services.

Although, when practical, these types of uses will be given special consideration when implementing the manual load-shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer’s equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be Customer’s responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses -- Except as described in Section III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use -- The priority of residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses -- The following and similar types of uses of electric energy shall be considered nonessential for all customers:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 107.1

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107.2

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

A. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

B. General interior lighting levels greater than minimum functional levels.

C. Show-window and display lighting.

D. Parking-lot lighting above minimum functional levels.

E. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

F. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

G. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

CURTAILMENT PROCEDURES

In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on curtailable contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Curtailable Service Rider tariff.
2. Power output will be maximized at Company's generating units.
3. Company use of energy at its generating stations will be reduced to a minimum.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 107.2

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107.3

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

CURTAILMENT PROCEDURES (continued)

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.
5. The Kentucky Public Service Commission will be advised of the situation.
6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.
7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.
8. Implement procedures for interruption of selected distribution circuits.

SERVICE RESTORATION PROCEDURES

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under PRIORITY LEVELS. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times to aid customers in assessing the need for alternative power sources and temporary relocations.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 107.3

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

CURTAILMENT PROCEDURES (continued)

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

P.S.C. Gas No. 10
Canceling P.S.C. Gas No. 9

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

In the seventeen counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

P.S.C. Gas No. 11
Canceling P.S.C. Gas No. 10

Louisville Gas and Electric Company

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Second Revision of Original Sheet No. 1
Canceling P.S.C. Gas No. 10, First Revision of Original Sheet No. 1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

DATE OF ISSUE: August 24, 2015

DATE EFFECTIVE: September 23, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 1.1
Canceling P.S.C. Gas No. 10, Original Sheet No. 1.1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

DATE OF ISSUE: August 24, 2015

DATE EFFECTIVE: September 23, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 1.1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: September 23, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 5
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 5

Standard Rate **RGS**
Residential Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term “residential” customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, personal vehicle fueling, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. Company shall not be obligated to install an additional service to a residential customer for the purpose of the customer installing equipment for either electric standby generation or personal vehicle fueling.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation or personal vehicle fueling shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, service for gas for use in standby electric generation and personal vehicle fueling shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

RATE

Basic Service Charge:	$13.50 per delivery point per month	
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.28693	
Gas Supply Cost Component	$ 0.41142	I
Total Gas Charge Per 100 Cubic Feet	$ 0.69835	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 5

Standard Rate **RGS**
Residential Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term “residential” customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, personal vehicle fueling, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS. Company shall not be obligated to install an additional service to a residential customer for the purpose of the customer installing equipment for either electric standby generation or personal vehicle fueling.

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Conditions. Additionally, service for gas for use in standby electric generation and personal vehicle **T**
fueling shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

RATE

Basic Service Charge per month:	$24.00 per delivery point	**T/I**
Plus a Distribution Charge per 100 cubic feet:	$ 0.25385	**T/R D**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 5.1

Standard Rate **RGS**
Residential Gas Service

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 5.1

Standard Rate **RGS**
Residential Gas Service

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The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	**T**
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
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TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 9
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 9

Standard Rate **VFD**
Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as;
1) having at least 12 members and a chief,
2) having at least one fire fighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge:	$13.50 per delivery point per month	
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.28693	I
Gas Supply Cost Component	$ 0.41142	I
Total Gas Charge Per 100 Cubic Feet	$ 0.69835	

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 9

Standard Rate **VFD**
Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation or personal vehicle fueling shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Company's Terms and Conditions. Additionally, service for gas for use in standby electric generation and personal vehicle fueling shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers. **T**

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:
1) having at least 12 members and a chief,
2) having at least one fire fighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge per month:	$24.00 per delivery point	**T/I**
Plus a Distribution Charge per 100 cubic feet:	$ 0.25385	**T/R D**

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	**T**
Gas Supply Clause	Sheet No. 85	
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

Standard Rate **VFD**

Volunteer Fire Department Service

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

Standard Rate **VFD**

Volunteer Fire Department Service

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 10

Standard Rate **CGS**
Firm Commercial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term “commercial” customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 10

Standard Rate **CGS**
Firm Commercial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term “commercial” customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Company’s Terms and Conditions. Additionally, service for **T**
gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 10.1
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 10.1

Standard Rate **CGS**
Firm Commercial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.21504	
Gas Supply Cost Component	0.41142	I
Total Charge Per 100 Cubic Feet	$ 0.62646	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 10.1

Standard Rate **CGS**
Firm Commercial Gas Service

RATE

Basic Service Charge per month:		T
If all of the customer's meters have a capacity < 5000 cf/hr:	$ 60.00 per delivery point	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$285.00 per delivery point	I
Plus a Distribution Charge per 100 cubic feet:	$ 0.26267	T/I D

Off-Peak Pricing Provision:
The Distribution Charge applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above. T

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Weather Normalization Adjustment	Sheet No. 88	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE T

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Standard Rate **CGS**
Firm Commercial Gas Service

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

LG&E Firm Commercial Gas Service Rate CGS is now contained on two pages instead of three pages.

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 15

Standard Rate **IGS**
Firm Industrial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term “industrial” customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, vehicular fueling of internal combustion engines, and for other similar uses. Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 15

Standard Rate **IGS**
Firm Industrial Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term “industrial” customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, vehicular fueling of internal combustion engines, and for other similar uses. Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Company’s Terms and Conditions. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers. **T**

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 15.1
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 15.1

Standard Rate **IGS**
Firm Industrial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 40.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$180.00 per delivery point per month

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	\$ 0.22779	
Gas Supply Cost Component	\$ 0.41142	I
Total Charge Per 100 Cubic Feet	\$ 0.63921	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by \$0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 15.1

Standard Rate **IGS**
Firm Industrial Gas Service

RATE

Basic Service Charge per month:		T
If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 165.00 per delivery point	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$750.00 per delivery point	I
Plus a Distribution Charge per 100 cubic feet:	\$ 0.21929	T/R D

Off-Peak Pricing Provision: **T**
The Distribution Charge applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by \$0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	T
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 15.2

Standard Rate **IGS**
Firm Industrial Gas Service

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 15.2

Standard Rate **IGS**
Firm Industrial Gas Service

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

Standard Rate **AAGS**
As-Available Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point.

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point. Customers not electing service under either Rate CGS or Rate IGS shall receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in “Contract-Term” below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE
Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM
Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

Standard Rate **AAGS**
As-Available Gas Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the provisions of this rate schedule. **T**

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual delivery point. **T**

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual delivery point. Customers not electing service under either Rate CGS or Rate IGS shall **T** receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in “Contract-Term” below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE
Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM
Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 20.1
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 20.1

Standard Rate **AAGS**
As-Available Gas Service

CONTRACT TERM (continued)

November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

RATE

Basic Service Charge:
$400.00 per delivery point per month

Plus a Charge Per Mcf

Distribution Cost Component	$ 0.7009	
Gas Supply Cost Component	$ 4.1142	I
Total Charge Per Mcf	$ 4.8151	I

The "Gas Supply Cost Component" as shown above is the cost per Mcf determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet Nos. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

PENALTY FOR FAILURE TO INTERRUPT

Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 20.1

Standard Rate **AAGS**
As-Available Gas Service

CONTRACT TERM (continued)

November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

RATE

Basic Service Charge per month:	$500.00 per delivery point	**T/I**
Plus a Distribution Charge per Mcf:	$1.0644	**T/I D**

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	**T**
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

PENALTY FOR FAILURE TO INTERRUPT

Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.2

Standard Rate **AAGS**
As-Available Gas Service

PENALTY FOR FAILURE TO INTERRUPT (continued)

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on "Contract Term", and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge applicable to any unauthorized takes of gas during the period of interruption (excluding Pilot Light Requirements where applicable) equal to $15.00 plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the period of interruption that falls into each monthly billing cycle, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the period of interruption that falls into each monthly billing cycle. Such penalty for failure to interrupt shall be in addition to any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules.

2. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 20.2

Standard Rate **AAGS**
As-Available Gas Service

PENALTY FOR FAILURE TO INTERRUPT (continued)

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on "Contract Term", and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge applicable to any unauthorized takes of gas during the period of interruption (excluding Pilot Light Requirements where applicable) equal to $15.00 plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the period of interruption that falls into each monthly billing cycle, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the period of interruption that falls into each monthly billing cycle. Such penalty for failure to interrupt shall be in addition to any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T**

2. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules. **T**

3. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder. **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.3

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

3. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer.

4. Customer shall discontinue taking service upon applicable notice by Company to do so.

5. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption.

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

7. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules.

8. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at any time thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall reimburse Company for the cost of the remote metering equipment, for any modifications to Company facilities, and for the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 20.3

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

4. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer. **T**

5. Customer shall discontinue taking service upon applicable notice by Company to do so. **T**

6. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption. **T**

7. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS. **T**

8. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules. **T**

9. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder. **T**

10. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at any time thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall reimburse Company for the cost of the remote metering equipment, for any modifications to Company facilities, and for the replacement of any existing meters required in order to facilitate the functioning of the remote metering. **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.4

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 20.4

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)
Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

D

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

The proposed LG&E Substitute Gas Sales Service Rate SGSS is not part of the current tariff.

Louisville Gas and Electric Company

Standard Rate **SGSS**
Substitute Gas Sales Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is required for any commercial or industrial customer that is physically connected to the facilities of any other provider of natural gas, bio-gas, native gas, methane, or other gaseous fuels, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. In the event that such Customer desires to continue to receive natural gas service from Company and/or declines to allow Company to remove Company's facilities hitherto used to provide natural gas service to Customer, then Customer shall be obligated to take service under Rate SGSS.

Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

Company may decline to serve customers using gas to generate electricity in standby or other applications under this rate schedule.

Customers shall be classified as commercial or industrial in accordance with the definitions set forth in either Rate CGS or Rate IGS, as applicable to customer's primary gas use.

RATE
For commercial customers, the following charges shall apply:

Basic Service Charge per month:	$285.00 per delivery point
Plus a Demand Charge:	$6.27 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.3767 per Mcf delivered

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

The proposed LG&E Substitute Gas Sales Service Rate SGSS is not part of the current tariff.

RATE (continued)
For industrial customers, the following charges shall apply:

Basic Service Charge per month:	$750.00 per delivery point
Plus a Demand Charge:	$10.90 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.2992 per Mcf delivered

MAXIMUM DAILY QUANTITY
Company shall provide firm natural gas sales service to Customer at a single Point of Delivery up to the Maximum Daily Quantity ("MDQ"). Customer and Company may mutually agree to establish the level of the MDQ; provided, however, that in the event that Customer and Company cannot agree upon the MDQ, then the level of the MDQ shall be equal to the highest daily volume used by Customer during the twelve (12) months prior to the date that Customer began receiving natural gas from another supplier with which Customer is physically connected; in the event that such daily gas usage is not available, then the MDQ shall be equal to the Customer's average daily use for the highest month's gas use in the twelve (12) months prior to the date that Customer began receiving natural gas from another supplier with which Customer is physically connected; in no case shall the MDQ be greater than 5,000 Mcf/day.

Service by Company to Customer in excess of the MDQ shall be provided by Company on an interruptible basis. The maximum hourly volume that Company shall be obligated to deliver to Customer shall not exceed 1/16th of the MDQ.

MONTHLY BILLING DEMAND
The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered during the current month or the previous eleven (11) monthly billing periods. The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

Regardless of the Monthly Billing Demand established by Customer, Company's obligation to provide firm natural gas sales service up to the MDQ shall be limited to the MDQ.

MINIMUM CHARGE
The minimum monthly bill shall be equal to all of the charges under this rate schedule, including, but not limited to, the basic service charge, the monthly demand charge, any volumetric charges, and any adjustment clauses.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

The proposed LG&E Substitute Gas Sales Service Rate SGSS is not part of the current tariff.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Gas Supply Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

2. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the MDQ, Delivery Point, delivery pressure, and any other matters relating to individual Customer circumstances.

3. On no day shall Company be obligated to supply gas in excess of Customer's MDQ. In order to effectuate Company's obligation, Company may install such remote flow equipment as it determines to be necessary in order to control and limit the amount of gas taken by Customer from Company, such facilities to be installed by Company at Customer's expense.

4. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

5. Any Customer contracting for service hereunder shall be required, prior to commencing service hereunder, to have appropriate remote metering devices. The remote metering devices allow Company to monitor Customer's usage. The Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering. Company may also install at Customer's expense, any backflow protection devices and/or flow control equipment as may be required in sole discretion of Company. The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering or other facilities determined to be the

The proposed LG&E Substitute Gas Sales Service Rate SGSS is not part of the current tariff.

Louisville Gas and Electric Company

Standard Rate SGSS
Substitute Gas Sales Service

SPECIAL TERMS AND CONDITIONS (continued)

installation and operation of such remote metering or other facilities determined to be necessary by Company. The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

6. Company will have the right to curtail or interrupt the delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

TERM OF CONTRACT

The minimum term for service hereunder shall be for a period of one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of MDQ or other special circumstances. After the expiration of the primary term, the contract may be terminated by either Company or Customer upon one year's prior written notice.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV.

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity ("MDQ") in excess of 20,000 Mcf/day. In the event that Customer's MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rate schedule.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV.

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the provisions herein set forth and to the **T**
availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity ("MDQ") in excess of 20,000 Mcf/day. In the event that Customer's MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rate schedule.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.1

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply.

Administrative Charge: $550.00 per Delivery Point per month

Distribution Charge Per Mcf: $0.4302

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.1

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 7 of the Special Terms and Conditions. **T**

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply: **T**

Administrative Charge per month:	$550.00 per Delivery Point	**T**
Plus a Distribution Charge per Mcf:	$ 0.4428	**T/I**

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 30.2
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 30.2

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rate FT effective November 1, 2015, the Gas Cost True-Up Charge shall be: T

$(0.0375) per Mcf for Bills Rendered On and After November 1, 2016 R/T

For customers electing service under Rate FT effective November 1, 2016, the Gas Cost True-Up Charge shall be: T

$0.0467 per Mcf for Bills Rendered On and After November 1, 2016 I/T

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula:

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

Payment of the Minimum Daily Threshold Charge is not a remedy for Customer's failure to meet the Minimum Daily Threshold Requirement for service under Rate FT. In the event that Customer does not meet the Minimum Daily Threshold Requirement for one-hundred twenty (120) days during a given Contract Year, service to Customer under Rate FT may be discontinued by Company. Customer will receive thirty (30) days prior written notice that Customer will be removed from Rate FT and returned to firm sales service under either Rate CGS or IGS as applicable.

DATE OF ISSUE: October 25, 2016

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.2

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings. **T**

For customers electing service under Rate FT effective November 1, 2015, the Gas Cost True-Up Charge shall be:

$(0.0375) per Mcf for Bills Rendered On and After November 1, 2016

For customers electing service under Rate FT effective November 1, 2016, the Gas Cost True-Up Charge shall be:

$0.0467 per Mcf for Bills Rendered On and After November 1, 2016

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula:

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision to Original Sheet No. 30.3
Canceling P.S.C. Gas No. 10, Original Sheet No. 30.3

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

IMBALANCES
Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

DATE OF ISSUE: August 17, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.3

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)
Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	**T**
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

IMBALANCES
Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.4

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to $\leq$5%	100%
>5% to $\leq$10%	90%
>10% to $\leq$15%	80%
>15% to $\leq$20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.4

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

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0% to $\leq$5%	100%
>5% to $\leq$10%	90%
>10% to $\leq$15%	80%
>15% to $\leq$20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.5

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to <u><</u>5%	100%
>5% to <u><</u>10%	110%
>10% to <u><</u>15%	120%
>15% to <u><</u>20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.5

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to <u><</u>5%	100%
>5% to <u><</u>10%	110%
>10% to <u><</u>15%	120%
>15% to <u><</u>20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

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UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

UTILIZATION CHARGE FOR DAILY IMBALANCES (continued)

Daily Demand Charge:	$0.1608 per Mcf	R
Daily Storage Charge:	$0.1833	
Utilization Charge for Daily Imbalances:	$0.3441 per Mcf	R

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume unless an OFO has been issued. If an OFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable and further described below under “Operational Flow Orders.” Customers not in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order (“OFO”) which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect and shall include information related to the OFO. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool, it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

UTILIZATION CHARGE FOR DAILY IMBALANCES (continued)

Daily Demand Charge:	$0.1608 per Mcf	
Daily Storage Charge:	0.2785	I
Utilization Charge for Daily Imbalances:	$0.4393 per Mcf	I

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume unless an OFO has been issued. If an OFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable and further described below under “Operational Flow Orders.” Customers not in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order (“OFO”) which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect and shall include information related to the OFO. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool, it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.7

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

OPERATIONAL FLOW ORDERS (continued)

is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Unauthorized receipts or deliveries during the effectiveness of an OFO shall be subject to an OFO Charge per Mcf for each Mcf of unauthorized receipts or deliveries, as applicable. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge per Mcf shall be equal to $15.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated. Such OFO Charge shall be in addition to any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2014-00372 dated June 30, 2015**

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.7

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

OPERATIONAL FLOW ORDERS (continued)

is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Unauthorized receipts or deliveries during the effectiveness of an OFO shall be subject to an OFO Charge per Mcf for each Mcf of unauthorized receipts or deliveries, as applicable. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge per Mcf shall be equal to $15.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated. Such OFO Charge shall be in addition to any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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2014-00372 dated June 30, 2015**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.8

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances.

2. As further described below, Customer shall specify to Company the daily volume of gas required by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.8

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions T
applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor T
inconsistent, with the specific provisions hereof. T

2. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances. T

3. As further described below, Customer shall specify to Company the daily volume of gas required by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. T T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.9

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

SPECIAL TERMS AND CONDITIONS (continued)

system for Customer's account. Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

3. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 30.9

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

SPECIAL TERMS AND CONDITIONS (continued)

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service. **T**

4. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The maximum hourly volume that Company shall be obligated to deliver shall not exceed 1/24th of the MDQ. The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis. **T** **T** **T**

5. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Company's Terms and Conditions. **T** **T**

6. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter. **T**

7. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition. **T**

8. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements. **T**

9. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the provisions of this rate schedule. **T**

10. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data. **T** **T**

D

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.10

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

SPECIAL TERMS AND CONDITIONS (continued)

8. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the terms and conditions of this rate schedule.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

LG&E Firm Transportation Service Rate FT is now contained on 10 pages instead of 11 pages.

Louisville Gas and Electric Company

Standard Rate **DGGS**

Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE

Gas sales service under this rate schedule shall be considered firm.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

Standard Rate **DGGS**

Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE

Gas sales service under this rate schedule shall be considered firm.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 35.1
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 35.1

Standard Rate — **DGGS**
Distributed Generation Gas Service

RATE

In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	
Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.1263	
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$0.03329	
Gas Supply Cost Component	0.41142	I
Total Charge Per 100 Cubic Feet	$0.44471	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity (“MDQ”), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 35.1

Standard Rate — **DGGS**
Distributed Generation Gas Service

RATE

In addition to any other charges set forth herein, the following charges shall apply: **T**

Basic Service Charge per month: **T**

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 165.00 per delivery point	**I**
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$750.00 per delivery point	**I**
Plus a Demand Charge:	$ 1.08978 per 100 cubic feet of Monthly Billing Demand	**T/R**
Plus a Distribution Charge:	$ 0.02992 per 100 cubic feet	**T/R D**

The total monthly minimum bill shall be the sum of the minimum Demand Charge and the Basic Service Charge. **T**

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity (“MDQ”), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84	
Gas Supply Clause	Sheet No. 85	**T**
Franchise Fee and Local Tax	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 35.2

Standard Rate **DGGS**
Distributed Generation Gas Service

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate ("MHR"), and the maximum daily quantity ("MDQ"). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer's installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf.

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS
Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 35.2

Standard Rate **DGGS**
Distributed Generation Gas Service

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions **T**
applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, **T**
with the specific provisions hereof. **T**

2. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances. **T**

3. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof. **T**

4. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate ("MHR"), and the maximum daily quantity ("MDQ"). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer's installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf. **T**

5. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less. **T**

6. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract. **T**

7. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company. **T**

D

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 36 **N**

Standard Rate **LGDS**
Local Gas Delivery Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is available to any party who contracts with Company to provide firm transportation service of local gas (including landfill gas, bio-gas, synthetic gas, and locally produced natural gas) where and when such transportation will not, in the sole discretion of Company, interfere with the operation of Company's storage or other facilities, or the delivery of gas to Company's retail sales or end-use gas transportation customers. Customer must meet the eligibility requirements further described hereunder and shall deliver gas meeting the gas quality standards incorporated into this rate schedule.

Customer shall request Company to utilize its system to transport, by displacement, such local gas to the Delivery Point. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Company shall not be required to install any facilities of any kind to serve a Customer under this rate schedule. In the event that Company is agreeable to the installation or alteration of any facilities as may be required to serve Customer, then Customer shall execute a separate contract for the construction of such facilities and shall pay for all costs of those facilities. Company shall not be obligated to extend its mains to facilitate service hereunder. Company's "Gas Main Extension Rules" shall not apply to service under this rate schedule.

Company and Customer shall enter into an Interconnect Facility Agreement covering the design, ownership, operation, and maintenance of the Interconnect Facility, including, but not limited to, any cost reimbursement provisions. Company shall own and operate the Interconnect Facility (including, but not limited to, regulation, meters, chromatograph, control valves, taps, insulators, rights-of-way, and related facilities) as are required to effectuate service hereunder. The Interconnect Facility shall be designed and constructed in accordance with Company's specifications. Company shall own and install facilities downstream of the Interconnect Facility required to connect the Interconnect Facility to Company's mainline gas system. Company shall be reimbursed by Customer for the costs of such downstream facilities and their installation as well as the costs to construct, operate, and maintain the Interconnect Facility. Customer may be required by Company to provide adequate surety to cover the costs incurred by Company related to either the Interconnect Facility or the related downstream facilities. The outlet of the Interconnect Facility shall be the Receipt Point as the latter term is used herein.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Customer shall warrant, in its Service Agreement, that all gas transported under this rate schedule shall be consumed within the Commonwealth of Kentucky. If Customer is unable to warrant that such gas is so consumed, then Company's transportation service shall be deemed interstate service and may only be provided pursuant to authorization from the Federal Energy Regulatory Commission ("FERC") and subject to the terms and conditions of Company's Statement of Operating Conditions as filed with FERC. Customer shall not be allowed to combine interstate services with intrastate services. Any Customer requesting interstate and intrastate transportation service shall have separate contracts for each activity. Only one service, either interstate service or intrastate service, shall apply to a Receipt Point.

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point to the Delivery Point. The Delivery Point shall be a pool operating under either Rider PS-TS-2 or Rider PS-FT. Company shall receive gas from Customer for transportation at the Receipt Point and deliver that gas by displacement to the Delivery Point. Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver a volume of gas to the Delivery Point, either daily or monthly, which differs from the volume of gas delivered to Company at the Receipt Point. Company will provide service to meet imbalances only on an as-available basis, as set forth herein.

Company shall not be obligated to deliver gas to the Delivery Point in excess of the Maximum Daily Quantity ("MDQ") as further defined herein. Customer and Company shall mutually agree to establish the level of the MDQ; provided, however, that the MDQ shall not be less than 50 Mcf/day.

Company may decline to deliver volumes to the Delivery Point in excess of the MDQ or accept volumes from the Receipt Point that are in excess of the MDQ plus applicable Lost and Unaccounted for Gas ("LAUFG") as further defined herein.

Company may deliver volumes of gas to the Delivery Point in excess of the MDQ; provided, however, that such deliveries to the Delivery Point in excess of the MDQ shall establish a new Monthly Billing Demand as further defined herein. Regardless of the Monthly Billing Demand established by Customer, Company's obligation to provide firm natural gas transportation service shall be limited to the MDQ.

Volumes shall be delivered by Customer to Company at the Receipt Point as nearly as practicable at uniform daily rates of flow, that is, 1/24th of the daily Gross Nominated Volume as further defined herein.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 36.2 N

Standard Rate **LGDS**
Local Gas Delivery Service

RATE

Administrative Charge per month:	$550.00 per Receipt Point
Plus a Basic Service Charge per month:	$1,310.00 per Receipt Point
Plus a Demand Charge:	$2.57 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.0388 per Mcf of Net Nominated Volumes at the Delivery Point

The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered to the Delivery Point during the current month or the previous eleven (11) monthly billing periods.

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Company's Pipeline Transporter(s), then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Louisville Gas and Electric Company

MAXIMUM DAILY QUANTITY, NOMINATIONS AND NOMINATED VOLUMES

The MDQ shall represent the maximum volume which Customer shall be entitled to nominate and Company shall be obligated to deliver to the Delivery Point.

As further described below, Customer shall specify to Company the daily volumes of gas to be received at the Receipt Point (the "Gross Nominated Volume"). From such Gross Nominated Volume shall be deducted an allowance for Company's system average LAUFG expressed as a percentage and based on historical levels. Effective November 1, 2016, such LAUFG percentage is 2.69%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to Customer at least thirty (30) days prior to such November 1.

The Net Nominated Volume (the Gross Nominated Volume less applicable LAUFG) shall be stated in Mcf/day and converted to MMBtu/day using the conversion factor specified by Company. The Net Nominated Volume is the amount that shall be delivered to the Delivery Point.

For example, if Customer requests Company to receive 342 Mcf on a given day at the Receipt Point (the Gross Nominated Volume), and the LAUFG percentage is 5.0%, then the Net Nominated Volume shall be 325 Mcf [342 – (342 x 0.05)]. The Net Nominated Volume of 325 Mcf shall be converted to MMBtu using the conversion factor specified by Company.

At least ten (10) days prior to the beginning of each calendar month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the month. Any changes in daily nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time ("ECT") on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled at the Delivery Point by an authorized Pool Manager are considered Net Nominated Volumes. Company shall not be obligated to accept from Customer daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays observed by Company.

Customer shall submit in writing to Company the daily nominated volumes and such other information as may be required to effectuate the transportation of natural gas by using the appropriate Nomination Schedule as may be specified by Company from time to time and by giving appropriate notice as designated by Company.

Customer agrees to inform Company promptly of any changes in the delivery rate to Company of gas transported under this rate schedule or any other information with regard to scheduling of deliveries that Company reasonably requests or as may be required by proper regulatory authorities.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 36.4 **N**

Standard Rate **LGDS**
Local Gas Delivery Service

LOCAL GAS FLOW ORDERS

Company shall have the right to issue a Local Gas Flow Order ("LGFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the LGFO.

Notice of an LGFO shall be provided to Customer at least four (4) hours prior to the beginning of the gas day for which the LGFO is in effect and shall include information related to the LGFO. A shorter notice period may be given where necessary to protect the integrity of Company's gas system. Customer shall respond to an LGFO by adjusting its deliveries to Company's system as directed in the LGFO within the specified timeframe.

Upon issuance of an LGFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must nominate at the Receipt Point a Gross Nominated Volume that is no more than the daily amount being received by Company from Customer at the Receipt Point (Metered Receipts); or (b) Customer must nominate at the Receipt Point a Gross Nominated Volume that is no less than the daily amount being received by Company from Customer at the Receipt Point (Metered Receipts). Customer shall respond to an LGFO either by adjusting its Gross Nominated Volume at the Receipt Point or by adjusting volumes being received by Company from Customer at the Receipt Point. All volumes nominated by Customer at the Receipt Point in excess of volumes received by Company from Customer at the Receipt Point in violation of the above "condition (a)" LGFO shall constitute an unauthorized under-delivery by Customer to Company at the Receipt Point. All volumes nominated by Customer at the Receipt Point less than volumes received by Company from Customer at the Receipt Point in violation of the above "condition (b)" LGFO shall constitute an unauthorized over-delivery from Customer to Company at the Receipt Point. Unauthorized under-deliveries or over-deliveries during the effectiveness of an LGFO shall be subject to an LGFO Charge per Mcf for each Mcf of unauthorized under-deliveries or over-deliveries, as applicable. Customer shall be subject to the LGFO Charge on the day for which the LGFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized under-deliveries or over-deliveries that occur.

Company may, in its sole discretion, issue an LGFO to an individual Customer taking service under this rate schedule without issuing an LGFO to all Customers taking service under this rate schedule.

The LGFO Charge per Mcf shall be equal to $15.00 plus the higher of either (a) the daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the LGFO was violated, or (b) the daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the LGFO was violated. Such LGFO Charge shall be in addition to any other charges under this rate schedule.

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State Regulation and Rates
Louisville, Kentucky

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The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Company will not be required to provide service under this rate schedule if Customer does not comply with the terms or conditions of an LGFO. Payment of LGFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the LGFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company. As a result of Customer's failure to comply with the terms or conditions of service, including an LGFO, Company may take such actions as it deems necessary to suspend service to Customer.

If Customer fails to manage its use of Company's transportation service in strict conformance with the directives of an LGFO, then Company may at its sole discretion do one or more of the following immediately upon delivering oral or written notice to Customer: (1) suspend all gas transportation service to the extent necessary to protect the operational integrity of Company's system, (2) decline to deliver to the extent necessary the gas provided by Customer, (3) decline to receive to the extent necessary the volume tendered by Customer at the Receipt Point, and (4) permanently terminate service under this rate schedule. Any suspension or termination under this section shall be without prejudice to and in addition to any other rights and remedies of Company.

IMBALANCES

The terms "Imbalance" or "Imbalances" as used herein mean the difference between Customer's Gross Nominated Volume in Mcf of gas to be received by Company at the Receipt Point and the metered volume of gas in Mcf actually received by Company from Customer at the Receipt Point (Metered Receipts).

When Company can provide such balancing service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of +/-5% of the Gross Nominated Volume. Company shall issue an LGFO as set forth herein during periods when service cannot be provided to meet daily imbalances.

Company shall calculate on a daily and monthly basis Customer's imbalance resulting from the difference between Customer's Gross Nominated Volume in Mcf for receipt by Company at the Receipt Point and the Metered Receipts of gas in Mcf from Customer at the Receipt Point. This will be calculated as follows:

$$\text{Imbalance} = \text{Gross Nominated Volumes} - \text{Metered Receipts}$$

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Gross Nominated Volumes} - \text{Metered Receipts})}{\text{Gross Nominated Volumes}}$$

The term "day" or "daily" shall mean the period of time corresponding to the gas day as observed by Company.

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The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Louisville Gas and Electric Company

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤ 5%	100%
> 5% to ≤ 10%	90%
>10% to ≤ 15%	80%
>15% to ≤ 20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

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The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

The appropriate percentage shall be dependent on Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to < 5%	100%
> 5% to < 10%	110%
>10% to < 15%	120%
>15% to < 20%	130%
>20%	140%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to < 5%	100%
> 5% to < 10%	110%
>10% to < 15%	120%
>15% to < 20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

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The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

All such cash-out charges or credits, as applicable, shall be shown and included on Customer's monthly bill. The billing of these cash-out charges or credits shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATION IN MMBTU CONTENT

The reconciliation of the actual deliveries to the Delivery Point and Company's receipt of gas from Customer at the Receipt Point, including any variation in MMBtu content, occurs through the operation of the cash-out provision. If not reflected on the current month's bill, changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following month's bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance as calculated herein exceed +/- 5% of the Gross Nominated Volume on any day when an LGFO (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the imbalance in Mcf greater than +/- 5% of Gross Nominated Volume for each daily occurrence.

The Utilization Charge for Daily Imbalances is the sum of the following:

Daily Demand Charge:	$0.1608 per Mcf
Daily Storage Charge:	0.2785
Utilization Charge for Daily Imbalances:	$0.4393 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed the +/- 5% unless an LGFO has been issued. If an LGFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the LGFO directive, either "condition (a)" or "condition (b)" as applicable and further described above under "Local Gas Flow Orders". Customers not in violation of the LGFO directive, either "condition (a)" or "condition (b)" as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

MEASUREMENT OF GAS

Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Company's Terms and Conditions. All gas delivered by Customer to Company pursuant to this rate schedule shall be measured by Company using such gas meters, chromatograph, and other instrumentation as Company deems appropriate.

The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

REMOTE METERING

Any Customer contracting for service hereunder shall be required, prior to commencing service hereunder, to have appropriate remote metering devices. The remote metering devices allow Company to monitor receipts of gas from Customer.

Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities required in order to facilitate the functioning of the remote metering. Company may also install at Customer's expense, any backflow protection devices, remote flow equipment, and the like, as may be required in sole discretion of Company, in order to protect the integrity of Company's gas system. Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering or other facilities determined to be necessary by Company. Customer shall be responsible for providing the necessary and adequate electric and telecommunications service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. Customer shall be responsible for maintaining the necessary and adequate electric and telecommunications service to provide remote metering.

GAS QUALITY

Gas received hereunder shall be merchantable gas, commercially free from toxins, odors, dust, solids, gums, gum-forming constituents, gasoline, water, or any other foreign substances of any kind, including liquid matter and hydrocarbon liquids which may become separated from the gas in the course of transportation through Company's system, and which might interfere with its merchantability or cause injury to or interference with proper operation of lines, regulators, meters, or other appliances.

Furthermore, such receipts shall not contain, either in the gas or in any liquids with the gas, any microbiological organism, pathogen, active bacteria, or bacterial agent capable of producing or contributing to corrosion, operational problems, or other problems, or are injurious to utility facilities or cause the gas to be unmarketable. Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria and acid producing bacteria.

Customer agrees that it will indemnify Company and save it harmless from all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of any claim by any other persons or entity related to or arising from gas tendered by Customer to Company not meeting the quality specifications herein.

If the gas tendered by Customer for transport by Company fails at any time to conform to any of the specifications set forth herein, then Company shall so notify Customer and Company may, at its sole option and in addition to any other remedies available to Company, refuse to accept delivery pending correction by Customer.

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State Regulation and Rates
Louisville, Kentucky

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The proposed LG&E Local Gas Delivery Service Rate LGDS is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 36.10 N

Standard Rate **LGDS**
Local Gas Delivery Service

The table below sets forth the applicable specifications for the gas received hereunder by Company from Customer.

Component	Units	Low	High
Total Heating Value	Btu per scf	967	1110
Wobbe Index	Calculated by dividing the Total Heating Value (dry) of the gas (at standard conditions of 14.73 psia and 60 degrees Fahrenheit) by the square root of the specific gravity of the gas	1314	1400
Carbon Dioxide	Percent by volume (mole%)	0.00%	2.00%
Hydrogen	Percent by volume (mole%)	0.00%	0.00%
Water (or water vapor)	lbs. per MMscf	0	7
Ammonia	ppm	0	3
Hydrogen Sulfide	grains per 100 scf	0	0.25
Total Sulphur (not including any mercaptan sulphur)	grains per 100 scf	0	5
Oxygen	Percent by volume (mole%)	0.00%	0.10%
All non-hydrocarbon gases such as carbon dioxide, nitrogen, and oxygen (Total Dilutents and Inerts)	Percent by volume (mole%)	0.00%	4.00%
Non-methane Hydrocarbons (C2+) such as ethane	Percent by volume (mole%)	0.00%	12.00%
Heavier Hydrocarbons (C3, C4, C6, +) such as propane, propylene, butanes, hexanes	Percent by volume (mole%)	0.00%	1.50%
Delivery Temperature	degrees Fahrenheit	40	90
Hydrocarbon Dewpoint	degrees Fahrenheit	Less than 10	

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Louisville Gas and Electric Company

Standard Rate **LGDS**
Local Gas Delivery Service

Company shall have the unqualified right to commingle gas received for service hereunder with gas from other sources. Accordingly, gas received by Company shall be subject to such changes as may result from such commingling and Company shall, notwithstanding any other provisions herein, be under no obligation to deliver for Customer's account gas identical to that received by Company.

CREDITWORTHINESS

Customer shall upon request of Company agree to maintain an irrevocable letter of credit, cash prepayment, or such other financial instrument satisfactory to Company ("credit support") in order to assure Customer's performance of its obligations hereunder. In determining the level of the security to be required of Customer, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customer, the MDQ, the general creditworthiness of Customer, and Customer's prior credit record with Company, if any. The amount of the credit support shall not exceed two twelfths (2/12) of Customer's estimated annual bill. In the event that Customer defaults on its obligations under this rate schedule, Company shall have the immediate right to draw on such credit support to satisfy Customer's obligation hereunder. Such credit requirements shall be administered by Company in a nondiscriminatory manner.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

2. Service under this rate schedule shall be performed under a written contract between Customer and Company ("Service Agreement") which shall set forth specific arrangements as to the MDQ, volumes to be transported, Receipt Point, Delivery Point, Receipt Pressure, timing of receipts and deliveries of gas by Company, term, and any other matters relating to individual Customer circumstances.

3. Should Customer be unable to provide an amount of gas to Company at the Receipt Point equivalent to the Gross Nominated Volume (the Net Nominated Volume plus applicable LAUFG), Company will not be obligated hereunder to provide standby quantities of gas. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

4. Company will have the right to curtail or interrupt the delivery of gas hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

5. It is at all times the responsibility of Customer to deliver gas to the Receipt Point at a pressure ("Receipt Pressure") sufficient to cause the delivery of gas into the system of Company. Company shall not be obligated to modify either its facilities or its prevailing system operating pressures in order to effectuate the receipt of gas from Customer at the Receipt Point.

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Louisville, Kentucky

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Louisville Gas and Electric Company

Standard Rate **LGDS**

Local Gas Delivery Service

SPECIAL TERMS AND CONDITIONS

6. Customer hereby agrees to reimburse Company for all Kentucky sales tax, if any, assessed on the charges specified in this rate schedule. Customer's Kentucky Sales Tax Permit Account Number shall be provided to Company pursuant to Company's request.

7. As between Company and Customer, Customer shall be in exclusive control and possession of the gas until such gas has been delivered to Company at the Receipt Point and after such gas has been delivered to the Delivery Point. Company shall be in exclusive control and possession of such gas while it is in Company's system between the Receipt Point and the Delivery Point. Company shall have no liability while the gas is in the exclusive control of Customer and Customer shall have no liability (except for damage, loss, or injury caused by Company's transportation of gas that does not meet the quality standards set forth herein or that is delivered to Company in violation of any other provision of this Rate Schedule) while the gas is in the exclusive control of Company. Title to all gas delivered by Customer to Company for transportation under this rate schedule shall remain with Customer at all times during transportation by Company. Company shall not acquire or take title to the gas transported hereunder with the exception of any over-deliveries purchased through the operation of the cash-out mechanism described hereunder.

8. In no event shall Company be liable to Customer for consequential, indirect, special, punitive, or exemplary damages arising out of service provided hereunder.

9. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data.

TERM OF CONTRACT

The minimum term for service hereunder shall be for a period of one (1) year or through the following October 31, whichever period is shorter. Company, in its sole discretion, may require that a contract be executed for a longer initial term when deemed necessary by the size of MDQ or other special circumstances. After such initial term, service under this rate schedule automatically shall continue in full force and effect and from year to year (from November 1 through October 31, which period shall be defined as a "Contract Year"), until terminated by either Party hereto for any reason, or no reason, pursuant to written notice of termination given by one Party to the other Party by the April 30th prior to the next available November 1st termination date.

When the Parties have agreed upon the terms required to complete the contract for service hereunder, Company shall tender a Service Agreement to Customer reflecting such agreed upon terms. The Service Agreement shall be invalid unless signed by the requesting Party and returned to Company within thirty (30) days after Company provides such Service Agreement to Customer for execution.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 45

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a Customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a Customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1, the Customer will be charged $90.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS, IGS, and AAGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. Customers taking service under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of service.

INSPECTION CHARGE

With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $150.00 will be made for each additional trip.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 45

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a Customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a Customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1, the Customer will be charged $90.00 to cover the test and transportation costs.

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Customers under Rate Schedules RGS, VFD, CGS, IGS, and AAGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. Customers taking service under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of service. **T**

INSPECTION CHARGE

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 45.1

Special Charges

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 45.1

Special Charges

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

UNAUTHORIZED RECONNECT CHARGE N

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

2. A charge of $132.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a meter.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 15,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization

In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 51

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 15,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. **T**

In addition, transportation service hereunder will be subject to the provisions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers. **T**

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 51.1
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 51.1

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a third-party TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $550.00 per Delivery Point per month

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.1504	$2.2779	$0.7009	
Pipeline Supplier's Demand Component	0.8392	0.8392	0.8392	I
Total	$2.9896	$3.1171	$1.5401	I

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 51.1

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 7 of the Special Terms and Conditions. **T**

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a third-party TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge per month: $550.00 per Delivery Point **T**

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.6267	$2.1929	$1.0644	**I/R/I**
Pipeline Supplier's Demand Component	0.8392	0.8392	0.8392	
Total	$3.4659	$3.0321	$1.9036	**I/R/I**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 51.2
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 51.2

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

RATE (continued)

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rate FT. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rider TS-2 effective November 1, 2015, the Gas Cost True-Up Charge shall be: T

$(0.0375) per Mcf for Bills Rendered On and After November 1, 2016 R/T

For customers electing service under Rider TS-2 effective November 1, 2016, the Gas Cost True-Up Charge shall be: T

$0.0467 per Mcf for Bills Rendered On and After November 1, 2016 I/T

Minimum Annual Threshold Requirement and Charge: When Customer's annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 15,000 Mcf and the Customer's actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer's Annual Usage) times the Peak Period Distribution Charge

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 51.2

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

RATE (continued)

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rate FT. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

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Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer's Annual Usage) times the Peak Period Distribution Charge

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.3

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

RATE (continued)

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Optional Monthly Telemetry Charge: $300.00 per Delivery Point per month

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

At the time that the Customer executes a contract for service hereunder, Customer shall elect to either (1) pay for the cost of this remote metering equipment and the cost of its installation in an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified herein. Under either option, Customer shall reimburse Company for the cost of any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that Customer's service under Rider TS-2 becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 51.3

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

RATE (continued)

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

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Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

At the time that the Customer executes a contract for service hereunder, Customer shall elect to either (1) pay for the cost of this remote metering equipment and the cost of its installation in an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified herein. Under either option, Customer shall reimburse Company for the cost of any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

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DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.4

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in Rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

2. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 51.4

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS

1. Service under this rider will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T**

2. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances. **T**

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in Rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

3. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The maximum hourly volume that Company shall be obligated to deliver shall not exceed 1/24th of the MDQ. The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis. **T T T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.5

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS (continued)

3. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

4. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

5. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

6. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural gas hereunder.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 51.5

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS (continued)

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Company's Terms and Conditions. **T**
T

5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter. **T**

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition. **T**

7. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural gas hereunder. **T**

8. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data. **T**
T

D

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater..

CHARACTER OF SERVICE
The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer.

For customers served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer.

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and

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2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 52

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater.

CHARACTER OF SERVICE
The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer.

For customers served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer.

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and 10 mA or less, or as otherwise determined by the **T**

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52.1

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

CHARACTER OF SERVICE (continued)

10 mA or less, or as otherwise determined by the Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements.

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply.

For Customers Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $ 7.17

For Customers Not Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $24.34

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

SPECIAL TERMS AND CONDITIONS

1. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment.

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P.S.C. Gas No. 11, Original Sheet No. 52.1

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

CHARACTER OF SERVICE (continued)

Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements. **T**

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply: **T**

For Customers Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $ 7.17

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Monthly Charge: $24.34

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T**

2. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment. **T**

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52.2

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

2. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes.

3. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment.

4. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice.

5. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose.

6. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost.

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 52.2

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

3. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes. **T**

4. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment. **T**

5. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice. **T**

6. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose. **T**

7. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost. **T**

8. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder. **T**

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52.3

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

7. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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LG&E Gas Meter Pulse Service Rate GMPS is now contained on three pages instead of four pages.

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a "TS-2 Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A customer served under Rider TS-2 must join a Rider PS-TS-2 pool managed by a third-party Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a "TS-2 Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A customer served under Rider TS-2 must join a Rider PS-TS-2 pool managed by a third-party Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.1

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

ACTION ALERTS

Company shall have the right to issue an Action Alert ("AA") which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. It is the responsibility of the Pool Manager, not Company, to convey an AA to Customers in its TS-2 Pool. Pool Manager shall be responsible for complying with the directives contained in the AA.

Notice of an AA shall be provided to TS-2 Pool Manager at least eighteen (18) hours prior to the beginning of the gas day for which the AA is in effect. TS-2 Pool Manager shall respond to an AA by adjusting its deliveries to Company's system as directed in the AA within the specified timeframe.

Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Each Mcf delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge.

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge per Mcf shall be equal to $5.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the AA was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the AA was violated. Such Action Alert Charge shall be in addition to any other charges under this rider.

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.1

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

ACTION ALERTS

Company shall have the right to issue an Action Alert ("AA") which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. It is the responsibility of the Pool Manager, not Company, to convey an AA to Customers in its TS-2 Pool. Pool Manager shall be responsible for complying with the directives contained in the AA.

Notice of an AA shall be provided to TS-2 Pool Manager at least eighteen (18) hours prior to the beginning of the gas day for which the AA is in effect. TS-2 Pool Manager shall respond to an AA by adjusting its deliveries to Company's system as directed in the AA within the specified timeframe.

Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Each Mcf delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge.

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge per Mcf shall be equal to $5.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the AA was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the AA was violated. Such Action Alert Charge shall be in addition to any other charges under this rider.

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

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P.S.C. Gas No. 10, Original Sheet No. 59.2

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

IMBALANCES

Company will calculate on a daily and monthly basis the TS-2 Pool Manager's imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

$$\text{Imbalance} = \text{Metered Usage} - \text{Delivered Volumes}$$

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Metered Usage} - \text{Delivered Volumes})}{\text{Delivered Volumes}}$$

The term “day” or “daily” shall mean the period of time corresponding to the gas day as observed by the Pipeline Transporter as adjusted for local time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.2

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

IMBALANCES

Company will calculate on a daily and monthly basis the TS-2 Pool Manager's imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

$$\text{Imbalance} = \text{Metered Usage} - \text{Delivered Volumes}$$

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{(\text{Metered Usage} - \text{Delivered Volumes})}{\text{Delivered Volumes}}$$

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CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.3

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.3

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.4

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.4

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Second Revision of Original Sheet No. 59.5
Canceling P.S.C. Gas No. 10, First Revision of Original Sheet No. 59.5

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

NOMINATIONS AND NOMINATED VOLUME (continued)

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2016, such LAUFG percentage is 2.69%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG percentage is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SUPPLIER CODE OF CONDUCT

Each PS-TS-2 Pool Manager participating in the Company's transportation program under Rider PS-TS-2 must:

1. communicate to participating Customers in clear, understandable terms the Customer's rights and responsibilities. This communication must include (a) the PS-TS-2 Pool Manager's customer service address and local or toll-free telephone number; and (b) a statement describing the PS-TS-2 Pool Manager's dispute resolution procedures;

2. provide in writing pricing and payment terms that are clearly defined and understandable and that inform consumers whether the price that the Customer will pay is inclusive or exclusive of applicable taxes, and Company approved tariff riders and surcharges;

3. refrain from engaging in communications or promotional practices which are fraudulent, deceptive, or misleading;

4. deliver gas to the Company on a firm basis on behalf of the Customers enrolled in the PS-TS-2 Pool Manager's pool in accordance with the requirements of the PS-TS-2 Pool Management Agreement;

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.5

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

NOMINATIONS AND NOMINATED VOLUME (continued)

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2016, such LAUFG percentage is 2.69%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG percentage is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SUPPLIER CODE OF CONDUCT

Each PS-TS-2 Pool Manager participating in the Company's transportation program under Rider PS-TS-2 must:

1. communicate to participating Customers in clear, understandable terms the Customer's rights and responsibilities. This communication must include (a) the PS-TS-2 Pool Manager's customer service address and local or toll-free telephone number; and (b) a statement describing the PS-TS-2 Pool Manager's dispute resolution procedures;

2. provide in writing pricing and payment terms that are clearly defined and understandable and that inform consumers whether the price that the Customer will pay is inclusive or exclusive of applicable taxes, and Company approved tariff riders and surcharges;

3. refrain from engaging in communications or promotional practices which are fraudulent, deceptive, or misleading;

4. deliver gas to the Company on a firm basis on behalf of the Customers enrolled in the PS-TS-2 Pool Manager's pool in accordance with the requirements of the PS-TS-2 Pool Management Agreement;

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.6

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SUPPLIER CODE OF CONDUCT

5. establish and maintain a credit-worthy financial position that enables PS-TS-2 Pool Manager to indemnify the Company and the Customers for costs incurred as a result of any failure by the PS-TS-2 Pool Manager to deliver gas in accordance with the requirements of Rider PS-TS-2 and to assure payment of any applicable charges for any such failure;
6. refrain from requesting customer-specific billing, payment, and usage history without first having received the Customer's written approval allowing PS-TS-2 Pool Manager to access such information.

Failure to fulfill any of these obligations shall be considered a violation of the Supplier Code of Conduct.

If the PS-TS-2 Pool Manager fails to comply with the Supplier Code of Conduct, the Company will have the discretion to temporarily suspend or terminate such PS-TS-2 Pool Manager from further participation in the transportation program under Rider PS-TS-2. If service to the PS-TS-2 Pool Manager is suspended or terminated, Customer(s) in the PS-TS-2 Pool Manager's Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS) until said Customer(s) join another PS-TS-2 Pool Manager's Pool. If the Company seeks to suspend or terminate service to a PS-TS-2 Pool Manager, Company shall first notify the PS-TS-2 Pool Manager of the alleged violations which merit suspension or termination. Such notice must be in writing and must be sent to the PS-TS-2 Pool Manager as specified in the notice provisions of the PS-TS-2 Pool Management Agreement at least five (5) business days prior to the effective date of the suspension or termination.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.

2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.6

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SUPPLIER CODE OF CONDUCT

5. establish and maintain a credit-worthy financial position that enables PS-TS-2 Pool Manager to indemnify the Company and the Customers for costs incurred as a result of any failure by the PS-TS-2 Pool Manager to deliver gas in accordance with the requirements of Rider PS-TS-2 and to assure payment of any applicable charges for any such failure;

6. refrain from requesting customer-specific billing, payment, and usage history without first having received the Customer's written approval allowing PS-TS-2 Pool Manager to access such information.

Failure to fulfill any of these obligations shall be considered a violation of the Supplier Code of Conduct.

If the PS-TS-2 Pool Manager fails to comply with the Supplier Code of Conduct, the Company will have the discretion to temporarily suspend or terminate such PS-TS-2 Pool Manager from further participation in the transportation program under Rider PS-TS-2. If service to the PS-TS-2 Pool Manager is suspended or terminated, Customer(s) in the PS-TS-2 Pool Manager's Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS) until said Customer(s) join another PS-TS-2 Pool Manager's Pool. If the Company seeks to suspend or terminate service to a PS-TS-2 Pool Manager, Company shall first notify the PS-TS-2 Pool Manager of the alleged violations which merit suspension or termination. Such notice must be in writing and must be sent to the PS-TS-2 Pool Manager as specified in the notice provisions of the PS-TS-2 Pool Management Agreement at least five (5) business days prior to the effective date of the suspension or termination.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.
2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.7

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

3. The TS-2 Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS-2 Pool Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

   Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool.

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State Regulation and Rates
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Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

3. The TS-2 Pool Manager shall upon request of Company agree to maintain an irrevocable letter T
of credit or such other financial instrument satisfactory to Company in order to assure TS-2 Pool T
Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

   Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.8

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.

6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.

7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 59.8

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.

6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.

7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

8. Pool Manager shall enter into a Website Subscriber Agreement if Pool Manager desires to access **T**
telemetry data. **T**

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 61

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to "FT Pool Managers".

For the purpose of this rider, a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE
In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager:

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE
Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool.

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 61

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to "FT Pool Managers".

For the purpose of this rider, a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE
In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager:

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE
Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool.

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 61.1

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

CHARACTER OF SERVICE (continued)
Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances.

VARIATIONS IN MMBTU CONTENT
All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

   The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) days prior to the end of a billing period.

   The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 61.1

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

CHARACTER OF SERVICE (continued)
Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances.

VARIATIONS IN MMBTU CONTENT
All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

   The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) days prior to the end of a billing period.

   The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 61.2

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

SPECIAL TERMS AND CONDITIONS (continued)

3. The FT Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 61.2

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

SPECIAL TERMS AND CONDITIONS (continued) **T**

3. The FT Pool Manager shall upon request of Company agree to maintain an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT.

8. Pool Manager shall enter into a Website Subscriber Agreement if Pool Manager desires to access telemetry data. **T** **T**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 62

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY
In all territory served.

AVAILABILITY OF SERVICE
This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to main extensions or to other facilities which are necessary to provide basic gas service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES
Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

EXCESS FACILITIES CHARGE
Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With No Contribution-in-Aid-of-Construction 1.24%

(b) making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With Contribution-in-Aid-of-Construction 0.47%

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 62

Standard Rate Rider **EF**
Excess Facilities

APPLICABILITY
In all territory served.

AVAILABILITY OF SERVICE
This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to main extensions or to other facilities which are necessary to provide basic gas service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

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EXCESS FACILITIES CHARGE
Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. No adjustment in the monthly charge for a replacement of facilities will be made during the initial five (5) year term of contract.

Customer shall pay for excess facilities by:

(a) making a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With No Contribution-in-Aid-of-Construction 1.24%

(b) making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:

Percentage With Contribution-in-Aid-of-Construction 0.47%

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 62.1

Standard Rate Rider **EF**
Excess Facilities

PAYMENT
The Excess Facilities Charges shall be incorporated with the bill for gas service and will be subject to the same payment provisions.

TERM OF CONTRACT
The initial term of contract to Customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 62.1

Standard Rate Rider **EF**
Excess Facilities

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The Excess Facilities Charges shall be incorporated with the bill for gas service and will be subject to the same payment provisions.

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The initial term of contract to Customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 63

Standard Rate Rider **NGV**
Natural Gas Vehicle Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing compressed natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than the compression of natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

CHARACTER OF SERVICE
Company will provide Customer with uncompressed natural gas pursuant to either Rate IGS or Rate FT, as applicable. A customer served under Rate IGS that meets the qualifications for service under Rider TS-2 may also transport gas pursuant to Rider TS-2.

Customer shall be responsible for installing, owning, and maintaining all facilities required to operate its fueling station.

The compression of natural gas to the pressure required for use as a motor vehicle fuel will be conducted by Customer using facilities installed, owned and operated by Customer.

RATE
The rates, provisions, and special terms and conditions of Rate IGS, Rider TS-2, or Rate FT as applicable to the Customer shall apply.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015**

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 63

Standard Rate Rider **NGV**
Natural Gas Vehicle Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under **T** this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than as natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or **T** boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

CHARACTER OF SERVICE
Company will provide Customer with uncompressed natural gas pursuant to either Rate IGS or Rate FT, as applicable. A customer served under Rate IGS that meets the qualifications for service under Rider TS-2 may also transport gas pursuant to Rider TS-2.

Customer shall be responsible for installing, owning, and maintaining all facilities required to operate its fueling station.

The compression of natural gas to the pressure required for use as a motor vehicle fuel will be conducted by Customer using facilities installed, owned and operated by Customer.

RATE
The rates, provisions, and special terms and conditions of Rate IGS, Rider TS-2, or Rate FT as applicable to the Customer shall apply.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 63.1

Standard Rate Rider **NGV**
Natural Gas Vehicle Service

SPECIAL CONDITIONS

1. Company reserves the right to inspect customer's premises to ensure gas provided pursuant to this Rider is only used for vehicular fuel. Any other use of gas by Customer may result in termination of service.

2. Service under this Rider shall be performed under a written contract between Customer and Company containing such provisions regarding delivery pressure, indemnification, and other matters as the Company deems necessary or desirable with respect to a particular customer.

3. Customer shall be responsible for and shall reimburse the Company for all taxes (including, but not limited to, any motor vehicle taxes) payable by the Company to any governmental body on sales of gas and/or for services rendered under this Rider.

4. The "Resale of Gas" provision set forth in the "Terms and Conditions" of Company's Tariff shall not apply to service provided under this Rider. Customer may resell gas received from Company under this Rider for use as a fuel in vehicular internal combustion engines.

5. Customer is solely responsible for compliance with codes and standards, permitting requirements, regulations, and laws related to the use of compressed natural gas and the operation of a natural gas vehicle fueling station, whether as a fleet operation or as a public fueling station. Company is not responsible for vehicle fueling.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 63.1

Standard Rate Rider **NGV**
Natural Gas Vehicle Service

SPECIAL TERMS AND CONDITIONS **T**

1. Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. **T T T T**

2. Company reserves the right to inspect customer's premises to ensure gas provided pursuant to this Rider is only used for vehicular fuel. Any other use of gas by Customer may result in termination of service. **T**

3. Service under this Rider shall be performed under a written contract between Customer and Company containing such provisions regarding delivery pressure, indemnification, and other matters as the Company deems necessary or desirable with respect to a particular customer. **T**

4. Customer shall be responsible for and shall reimburse the Company for all taxes (including, but not limited to, any motor vehicle taxes) payable by the Company to any governmental body on sales of gas and/or for services rendered under this Rider. Customer shall be solely responsible for the reporting and payment of all applicable federal and state motor fuel taxes including, but not limited to, any federal special fuel excise tax and any state motor fuel tax. **T T T T**

5. The Resale of Gas provision set forth in the Company's Terms and Conditions shall not apply to service provided under this Rider. Customer may resell gas received from Company under this Rider for use as a fuel in vehicular internal combustion engines. **T**

6. Customer is solely responsible for compliance with codes and standards, permitting requirements, regulations, and laws related to the use of compressed natural gas and the operation of a natural gas vehicle fueling station, whether as a fleet operation or as a public fueling station. Company is not responsible for vehicle fueling. **T**

D

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Second Revision of Original Sheet No. 84
Canceling P.S.C. Gas No. 10, First Revision of Original Sheet No. 84

Adjustment Clause **GLT**
Gas Line Tracker

APPLICABLE
Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT
The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals;
e. Incremental Operation and Maintenance; and
f. Property Taxes

GLT PROGRAM FACTORS
All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS shall be assessed an adjustment to their applicable rate schedule that will enable the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2014-00372.

A filing to update the projected program costs will be submitted annually at least two (2) months prior to the beginning of the effective period. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective with the first billing cycle on or after the effective date of such change.

GLT RATES
The charges for the respective gas service schedules are:

RGS – Residential Gas Service	$ 5.14
VFD – Volunteer Fire Department Service	$ 5.14
CGS – Commercial Gas Service	$ 27.41
IGS – Industrial Gas Service	$ 259.54
AAGS – As-Available Gas Service	$ 2,838.87
DGGS – Distributed Generation Gas Service	$ 0.00

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00108 dated March 31, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 84

Adjustment Clause **GLT**
Gas Line Tracker

APPLICABLE
Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS,
IGS, AAGS, FT, SGSS, DGGS, and LGDS. **T**

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT
The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals;
e. Incremental Operation and Maintenance; and
f. Property Taxes

GLT PROGRAM FACTORS
After the Company replaces a gas service riser or a gas service line under this program, it will assume **T**
ownership and responsibility for the plant and equipment. The allocation of the program cost to
customers will be in proportion to their relative base revenue share approved in the Company's most **T**
recent general rate case. **T**

A filing to update the projected program costs will be submitted annually. The filing will reflect the **T**
anticipated impact on the Company's revenue requirements of net plant additions expected during the
current year. At the same time, the Company will submit a balancing adjustment to true up the actual **T**
costs with the projected program costs for the preceding year. Such adjustment to the GLT will become **T**
effective for services rendered on and after the first day of the following month after the effective date **T**
of such change. **T**

RATES
The charges for the respective gas service schedules are:

	Distribution Projects ($/delivery point)	Transmission Projects ($/Ccf)	
			T/N
RGS – Residential Gas Service	$ 0.84	$0.00067	**R/N**
VFD – Volunteer Fire Department Service	0.84	0.00067	**R/N**
CGS – Commercial Gas Service	4.26	0.00051	**R/N**
IGS – Industrial Gas Service	48.86	0.00020	**R/N**
AAGS – As-Available Gas Service	48.86	0.00020	**R/N**
SGSS – Substitute Gas Sales Service	4.26	0.00051	**N**
DGGS – Distributed Generation Gas Service	48.86	0.00020	**I/N**
FT – Firm Transportation Service	N/A	0.00003	**N**
LGDS – Local Gas Delivery Service	N/A	0.00003	**N**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Sixth Revision of Original Sheet No. 85
Canceling P.S.C. Gas No. 10, Fifth Revision of Sheet No. 85

Adjustment Clause **GSC**
Gas Supply Clause

APPLICABLE TO

All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.40675	I
Gas Cost Actual Adjustment (GCAA)	0.00259	I
Gas Cost Balance Adjustment (GCBA)	(0.00088)	I
Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:		
None		
Performance-Based Rate Recovery Component (PBRRC)	0.00296	
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.41142	I

DATE OF ISSUE: October 25, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 85

Adjustment Clause **GSC**
Gas Supply Clause

APPLICABLE TO

All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.40675
Gas Cost Actual Adjustment (GCAA)	0.00259
Gas Cost Balance Adjustment (GCBA)	(0.00088)
Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:	
None	
Performance-Based Rate Recovery Component (PBRRC)	0.00296
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.41142

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00353 dated October 18, 2016

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 85.1

Adjustment Clause **GSC**
Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 85.1

Adjustment Clause **GSC**
Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information:

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 85.2

Adjustment Clause **GSC**

Gas Supply Clause

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.

2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."

2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.

3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 85.2

Adjustment Clause **GSC**

Gas Supply Clause

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.

2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."

2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.

3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, and Firm Transportation Rate FT.

RATE
The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) of monthly gas consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:
DCR = DSM COST RECOVERY
The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program.
The cost of approved programs shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES
Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Substitute Gas Sales Service Rate SGSS, and Firm **T**
Transportation Rate FT.

RATE
The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) of monthly gas consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:
DCR = DSM COST RECOVERY
The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program. The cost of **T**
approved programs shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES
Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.1

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DRLS = DSM REVENUE FROM LOST SALES (continued)

1. For each upcoming twelve-month period, the estimated reduction in customer usage (in Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE.
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: With Bills Rendered On and After December 31, 2011

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 86.1

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DRLS = DSM REVENUE FROM LOST SALES (continued)

1. For each upcoming twelve-month period, the estimated reduction in customer usage (in Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Charge billings for the customer classes. **T**

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE.
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.2

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

DSMI = DSM INCENTIVE (continued)

The DSM incentive amount shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT.
The DBA shall be calculated on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest to be calculated at a rate equal to the average of the "Three-Month Commercial Paper Rate" for the immediately preceding twelve-month period. The balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: With Bills Rendered On and After December 31, 2011

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 86.2

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

DSMI = DSM INCENTIVE (continued)

The DSM incentive amount shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT.
The DBA shall be calculated on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest to be calculated at a rate equal to the average of the "Three-Month Commercial Paper Rate" for the immediately preceding twelve-month period. The balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: With Bills Rendered On and After December 31, 2011

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DCCR = DSM CAPITAL COST RECOVERY

The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

DCCR = [(RB) (ROR + (ROR – DR) (TR / (1 – TR))] + OE

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: May 31, 2012

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DCCR = DSM CAPITAL COST RECOVERY

The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

DCCR = [(RB) (ROR + (ROR – DR) (TR / (1 – TR))] + OE

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: May 31, 2012

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.4

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: With Service Rendered On
and After January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00003 dated November 14, 2014**

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 86.4

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES

Residential Customer Program Participation Incentives:
The following Demand Side Management programs are available to residential customers receiving service from the Company on the RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

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State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2014-00003 dated November 14, 2014**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.5

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES (continued)

Customer Education and Public Information

This program help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

Commercial Customer Program Participation Incentives:

The following Demand Side Management programs are available to commercial customers receiving service from the Company on the CGS, IGS, AAGS, and FT Standard Gas Rate Schedules.

Customer Education and Public Information

This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 86.5

Adjustment Clause DSM

Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES (continued)

Customer Education and Public Information

This program help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

Commercial Customer Program Participation Incentives:

The following Demand Side Management programs are available to commercial customers receiving service from the Company on the CGS, IGS, AAGS, SGSS, and FT Standard Gas Rate Schedules. **T**

Customer Education and Public Information

This program helps customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

DATE OF ISSUE: November 23, 2016

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Second Revision of Original Sheet No. 86.6
Canceling P.S.C. Gas No. 10, First Revision of Original Sheet No. 86.6

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Gas Service Rate RGS and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.01788 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00079 per Ccf
DSM Incentive (DSMI)	$ 0.00083 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf
DSM Balance Adjustment (DBA)	$ (0.00866) per Ccf
Total DSMRC for Rates RGS and VFD	$ 0.01084 per Ccf

Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS,* and Firm Transportation Service Rate FT*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00086 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf
DSM Incentive (DSMI)	$ 0.00000 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf
DSM Balance Adjustment (DBA)	$ (0.00029) per Ccf
Total DSMRC for Rates CGS, AAGS, and FT	$ 0.00057 per Ccf

* This charge does not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

DATE OF ISSUE: February 29, 2016

DATE EFFECTIVE: March 31, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 86.6

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Gas Service Rate RGS and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.01788 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00079 per Ccf
DSM Incentive (DSMI)	$ 0.00083 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf
DSM Balance Adjustment (DBA)	$ (0.00866) per Ccf
Total DSMRC for Rates RGS and VFD	$ 0.01084 per Ccf

Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS*, Substitute Gas Sales Service Rate SGSS*, and Firm Transportation Service Rate FT*	Energy Charge	
		T
DSM Cost Recovery Component (DCR)	$ 0.00086 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf	
DSM Incentive (DSMI)	$ 0.00000 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf	
DSM Balance Adjustment (DBA)	$ (0.00029) per Ccf	
Total DSMRC for Rates CGS, AAGS, and FT	$ 0.00057 per Ccf	

* This charge does not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87
Canceling P.S.C. Gas No. 10, Original Sheet No. 87

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

APPLICABLE
To all gas sold.

RATE MECHANISM
The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$PBRRC = \frac{CSPBR + BA}{ES}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$CSPBR = TPBRR \times ACSP$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$TPBRR = (GAIF + TIF + OSSIF)$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

APPLICABLE
To all gas sold.

RATE MECHANISM
The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

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Where:

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CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$CSPBR = TPBRR \times ACSP$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$TPBRR = (GAIF + TIF + OSSIF)$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

DATE OF ISSUE: November 23, 2016

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.1
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.1

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The BGC shall include the benchmark component as follows:

BGC = TABMGCC

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm seasonal entitlements by pipeline and by zone for which indices are posted. The seasonal percentages represent the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company may have firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.1

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The BGC shall include the benchmark component as follows:

BGC = TABMGCC

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm seasonal entitlements by pipeline and by zone for which indices are posted. The seasonal percentages represent the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company may have firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.2
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.2

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, Gulf Coast, Onshore as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for Louisiana - Onshore South, Texas Gas, Zone SL averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas, Zone SL.

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, North as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for East Texas - North Louisiana Area, Texas Gas, zone 1 averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas, Zone 1.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.2

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, Gulf Coast, Onshore as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for Louisiana - Onshore South, Texas Gas, Zone SL averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas, Zone SL.

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, North as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for East Texas - North Louisiana Area, Texas Gas, zone 1 averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas, Zone 1.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.3
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.3

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Appalachia, Lebanon Hub.

I(2) is the *Platts Gas Daily* midpoint postings for Appalachia – Lebanon Hub averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast, Lebanon Hub.

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Texas, Gulf Coast, Onshore Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for South – Corpus Christi, Tennessee, Zone 0 averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee, Texas, Zone 0.

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, Gulf Coast, Onshore as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for Louisiana – Onshore South, Tennessee, 500 Leg averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee, Louisiana, 500 leg.

DAI (TGT-4) and (TGPL-2)

DAI is the Delivery Area Index to be established for **PEFDCQ** made by Company on the day(s) when Company has arranged for deliveries to Company's city gate that are in excess of its total firm pipeline quantity entitlements.

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DATE EFFECTIVE: November 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.3

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Appalachia, Lebanon Hub.

I(2) is the *Platts Gas Daily* midpoint postings for Appalachia – Lebanon Hub averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast, Lebanon Hub.

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Texas, Gulf Coast, Onshore Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for South – Corpus Christi, Tennessee, Zone 0 averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee, Texas, Zone 0.

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Louisiana, Gulf Coast, Onshore as Delivered to Pipeline.

I(2) is the *Platts Gas Daily* midpoint postings for Louisiana – Onshore South, Tennessee, 500 Leg averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee, Louisiana, 500 leg.

DAI (TGT-4) and (TGPL-2)

DAI is the Delivery Area Index to be established for **PEFDCQ** made by Company on the day(s) when Company has arranged for deliveries to Company's city gate that are in excess of its total firm pipeline quantity entitlements.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.4
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.4

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The daily DAI applicable to the daily purchases made for city-gate delivery shall be the higher of the following, either

DAI = DAI (TGT-1) / (1 – FR%) + CCS + DDCS

or

DAI = DAI (TGT-4) / (1 – FR%) + CCS + DDCS

Where:

DAI (TGT-1) represents the highest daily midpoint posting by *Platts Gas Daily* for East Texas – North Louisiana Area, Texas Gas, zone 1.

DAI (TGT-4) represents the highest daily midpoint posting by *Platts Gas Daily* for Appalachia – Lebanon Hub.

FR% is the tariffed Fuel Retention Percentage under Texas Gas Transmission, LLC's Rate NNS.

CCS are the tariffed NNS Commodity Charge and Surcharges under Texas Gas Transmission, LLC's Rate NNS.

DDCS are the tariffed Daily Demand Charge and Surcharges under Texas Gas Transmission, LLC's Rate NNS.

If an index ceases to exist or fails to report, the Company may use a suitable replacement index and report that change in writing to the Commission in the applicable quarterly report. If the Company elects not to select a replacement index, the average is adjusted accordingly.

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs (excluding any supply reservation fees) plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.4

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The daily DAI applicable to the daily purchases made for city-gate delivery shall be the higher of the following, either

DAI = DAI (TGT-1) / (1 – FR%) + CCS + DDCS

or

DAI = DAI (TGT-4) / (1 – FR%) + CCS + DDCS

Where:

DAI (TGT-1) represents the highest daily midpoint posting by *Platts Gas Daily* for East Texas – North Louisiana Area, Texas Gas, zone 1.

DAI (TGT-4) represents the highest daily midpoint posting by *Platts Gas Daily* for Appalachia – Lebanon Hub.

FR% is the tariffed Fuel Retention Percentage under Texas Gas Transmission, LLC's Rate NNS.

CCS are the tariffed NNS Commodity Charge and Surcharges under Texas Gas Transmission, LLC's Rate NNS.

DDCS are the tariffed Daily Demand Charge and Surcharges under Texas Gas Transmission, LLC's Rate NNS.

If an index ceases to exist or fails to report, the Company may use a suitable replacement index and report that change in writing to the Commission in the applicable quarterly report. If the Company elects not to select a replacement index, the average is adjusted accordingly.

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs (excluding any supply reservation fees) plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.5
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.5

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission, LLC.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company, LLC.

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

DATE OF ISSUE: July 20, 2015

DATE EFFECTIVE: November 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.5

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

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TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission, LLC.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company, LLC.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.6
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.6

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

DATE OF ISSUE: July 20, 2015

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.6

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 87.7
Canceling P.S.C. Gas No. 10, Original Sheet No. 87.7

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF = Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off-System Sales **(NR)**.

Net Revenue is calculated as follows:

NR = OSREV - OOPC

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm transportation contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.7

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

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Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm transportation contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\textbf{PTAGSC} = \frac{\textbf{TPBRR}}{\textbf{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\textbf{TAGSC} = \textbf{AGC} + \textbf{TAAGTC}$$

If the absolute value of the PTAGSC is less than or equal to 3.0%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 3.0%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 3.0% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 3.0% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

DATE OF ISSUE: July 20, 2015

DATE EFFECTIVE: November 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00476 dated June 30, 2015**

Louisville Gas and Electric Company

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\textbf{PTAGSC} = \frac{\textbf{TPBRR}}{\textbf{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\textbf{TAGSC} = \textbf{AGC} + \textbf{TAAGTC}$$

If the absolute value of the PTAGSC is less than or equal to 3.0%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 3.0%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 3.0% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 3.0% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

DATE OF ISSUE: November 23, 2016

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00476 dated June 30, 2015**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.9

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

DATE OF ISSUE: July 20, 2015

DATE EFFECTIVE: November 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 87.9

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: November 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00476 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 88

Adjustment Clause **WNA**

Weather Normalization Adjustment Clause Applicable to Rates RGS and CGS

WEATHER NORMALIZATION ADJUSTMENT (WNA)

The sales to Residential and Commercial Customers under Rate Schedules RGS and CGS shall be increased or decreased monthly by an amount hereinafter described as the Weather Normalization Adjustment (WNA).

Determination of WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the non-gas portion of the bills of all heating Customers served under Rate Schedules RGS and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

Weather Normalization Adjustment will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: September 7, 2000

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00459 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 88

Adjustment Clause **WNA**

Weather Normalization Adjustment Clause T

APPLICABLE

The sales to Residential Customers, Volunteer Fire Departments, and Commercial Customers under Rate Schedules RGS, VFD, and CGS shall be increased or decreased monthly by an amount hereinafter described as the WNA.

DETERMINATION OF WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the applicable Distribution Charges for Customers served under Rate Schedules RGS, VFD and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

WNA will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable Distribution Charge T
as set forth on the RGS, VFD, and CGS Rate Schedules. T

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 90

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 90

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: February 6, 2009

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 91

Adjustment Clause **ST**
School Tax

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE
The utility gross receipts license tax authorized under state law.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 91

Adjustment Clause **ST**
School Tax

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In all territory served.

AVAILABILITY OF SERVICE
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RATE
The utility gross receipts license tax authorized under state law.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 92

Adjustment Clause **HEA**
Home Energy Assistance

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

PURPOSE
Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 92

Adjustment Clause **HEA**
Home Energy Assistance

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per month. **T**

BILLING
The HEA charge shall be shown as a separate item on customer bills.

PURPOSE
Proceeds from this charge will be used to fund residential low-income demand-side management Home Energy Assistance programs which have been designed through a collaborative advisory process and then filed with, and approved by, the Commission.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 95

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 95

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service, unless any rate or rider under which you take service explicitly states otherwise. **T**
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions which shall constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR

The United Nations Convention on Contracts for the International Sale of Goods is specifically disclaimed and excluded and will not apply to or govern agreements between customers and Company.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which gas service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS **T**

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions to the extent that such Terms and Conditions are **T**
not in conflict, nor inconsistent, with the specific provisions in each rate schedule and which shall **T**
constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 96.1

TERMS AND CONDITIONS

General

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied gas service

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 96.1

TERMS AND CONDITIONS

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 97

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render gas service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

Applications for gas service are not transferable and new occupants of premises will be required to make application for service before commencing the use of gas. Customers who have been receiving gas service shall notify Company when discontinuance of service is desired, and shall pay for all gas service furnished until such notice has been given and final meter readings made by Company.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which Customer desires to receive service.

Company will, at any time, upon request, advise any Customer as to the most advantageous rate for existing or anticipated service requirements as defined by the Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, the Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customers will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 97

TERMS AND CONDITIONS

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 97.1

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER'S EQUIPMENT AND INSTALLATION.

Customer shall furnish, install, and maintain at Customer's expense the necessary Customer's Service Line extending from Company's Service Connection at the property line to the building or place of utilization of the gas.

All piping, appliances, and other gas equipment and apparatus, except the meter, regulator, and any gas riser or service line the Company has installed, repaired, or replaced, located on and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of gas service or for the purpose of turning on and shutting off the gas supply when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 97.1

TERMS AND CONDITIONS

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of gas, occasioned by such gas or said pipes and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution mains, Customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and across such intervening property of Customer's piping and facilities required for the supply of gas service to Customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. In the event that such Customer desires to continue to receive natural gas service from Company and/or declines to allow Company to remove Company's facilities hitherto used to provide natural gas service to Customer, then Customer shall be obligated to take service under Rate SGSS. T T T

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of gas, occasioned by such gas or said pipes and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

COMPANY-OWNED SERVICE LINES

The Company will install, own, operate and maintain the service line at the premises of residential and commercial customers, if such premises are not connected to a Company main by a service line. With respect to residential and commercial customers that occupy premises already connected to a Company main by a service line that the Company has installed, repaired, or replaced, the Company shall be responsible for operating and maintaining the customer service line and when the Company determines that replacement of such customer service line is necessary the Company shall be responsible for installing the service line and shall thereafter own the service line.

Any customer accepting gas service under this section shall be deemed to have granted the Company an easement across his property for such service. No service line shall be installed across private property other than the premises of the building to be supplied with gas, except after special investigation and approval by the Company.

When the length of the service pipe required between the property line and the meter is 100 feet or less, the Company will assess no charge for the service pipe installation.

When the length of required service pipe exceeds 100 feet, the Company may require the applicant to contribute toward the cost of the service line installation an amount equal to the estimated cost per foot for each lineal foot of service beyond 100 feet. Contributions by customers toward the Company's cost of furnishing and installing service lines in accordance with this section are non-refundable.

In the event that the Company is required to undertake any excavation on a customer's property in connection with the installation, repair, maintenance or replacement of a service line, the Company shall make reasonable efforts to restore the property to its original condition pursuant to generally accepted utility standards for such construction operations.

DATE OF ISSUE: July 10, 2015

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The gas used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

POINT OF DELIVERY OF GAS

The point of delivery of gas supplied by Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulating equipment.

If the Service Line is owned by the Customer, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulation equipment.

If the Service Line is owned by the Company, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the outlet of the meter to the Customer's yard line or house piping.

COMPANY'S EQUIPMENT AND INSTALLATION

The Company shall furnish, install, and maintain at its expense the necessary service connection. The location of this service connection will be made at the discretion and judgment of the Company.

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage or tamper with the same. Customer shall execute a reasonable form of easement agreement, if requested by Company.

DATE OF ISSUE: July 10, 2015

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State Regulation and Rates
Louisville, Kentucky

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customer, including without limitation a digital, automated meter reading, automated metering **T**
infrastructure, or advanced metering systems meter or meters. When service is supplied by **T**
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COMPANY'S EQUIPMENT AND INSTALLATION

The Company shall furnish, install, and maintain at its expense the necessary service connection. The location of this service connection will be made at the discretion and judgment of the Company.

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage or tamper with the same. Customer shall execute a reasonable form of easement agreement, if requested by Company.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2016-00371 dated xxxx**

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

COMPANY'S EQUIPMENT AND INSTALLATION (continued)

Notwithstanding the provisions of 807 KAR 5:006, Section 14(4), a reasonable time shall be allowed subsequent to Customer's service application to enable Company to construct or install the facilities required for such service. In order that Company may make suitable provision for enlargement, extension or alteration of its facilities, each applicant for commercial or industrial service shall furnish Company with realistic estimates of prospective gas requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of gas service delivered at Company's property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer's premises or resulting from defects in or accidents to any of Customer's piping, equipment, apparatus or appliances, or resulting from any cause whatsoever other than the negligence of Company.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the gas service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

OBLIGATION TO SERVE

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

COMPANY'S EQUIPMENT AND INSTALLATION (continued)

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 98.2

TERMS AND CONDITIONS

Company Responsibilities

Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

SPECIAL RULES FOR CUSTOMERS SERVED FROM HIGH PRESSURE MAINS, GAS TRANSMISSION MAINS, AND STORAGE GATHERING LINES

In order to ensure the integrity, safe operations, and reliability of the Company's gas system, these special rules apply to customers served from high pressure mains, gas transmission mains, and storage gathering lines.

When a customer requests service from a high pressure main, gas transmission main, or storage gathering line under Rate RGS, CGS, IGS, VFD, AAGS, or FT, Company shall determine, in its sole discretion, if service is justified, feasible, and consistent with good operating practice.

Upon approval by Company of a request by a customer (or group of customers) for service from a high pressure main, gas transmission main, or storage gathering line, then Company may charge the customer (or group of customers) in addition to the charges under the applicable rate schedule, the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

In no case, shall Company be obligated to provide service to customers served under Rate DGGS from a high pressure main, gas transmission main, or storage gathering line.

PURCHASE OF CERTAIN CUSTOMER-OWNED GAS SERVICE ENTRANCES AND RISERS.

LG&E will reimburse its gas customers who have replaced their service entrances or gas risers (or both) between January 1, 2011 and December 31, 2012. Customers must notify LG&E if they desire such reimbursement. LG&E has no obligation to seek out such customers. LG&E will post on its website a notice of the availability of this reimbursement. The reimbursement will be in the amount of the customers' reasonable costs of replacing such service entrances or gas risers (or both), which must be demonstrated to LG&E's reasonable satisfaction. Customers disputing the amount of reimbursement may contact the Commission. LG&E will reimburse only owners of affected properties, each of whom must have owned the affected property at the time of the replacement of the service entrance or gas riser.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 98.2

TERMS AND CONDITIONS

Company Responsibilities

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

STANDARD PRESSURE AND MEASUREMENT BASE

The standard distribution pressure of the gas supplied by Company is four ounces per square inch above atmospheric pressure.

Atmospheric pressure shall be assumed in all cases to be 14.5 pounds per square inch and temperature shall be assumed to be 60 degrees Fahrenheit; provided, however, Company reserves the right for billing purposes to correct as necessary the actual temperature to a 60 degree Fahrenheit basis in the case of large volume customers.

All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

DELIVERY PRESSURE

Company shall not be obligated to provide gas service to any Customer at a minimum delivery pressure greater than 50 psig or the expected minimum pipeline pressure, whichever is less.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot. All gas received into the system of Company from interstate pipelines shall meet the **T**
applicable quality standards of the respective interstate pipeline delivering natural gas to Company **T**
All gas received into the system of Company from sources other than an interstate pipeline shall **T**
meet the quality standards prescribed in Local Gas Delivery Service Rate LGDS. When it is **T**
necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 101

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

All bills will be based upon meter readings made in accordance with Company's meter reading schedule. Company, except if prevented by reasons beyond its control, shall read customers meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's electric or gas meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. However, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of rendition thereof. If full payment is not received by the due date of the bill, a late payment charge will be assessed on the current month's charges. Beginning October 1, 2010, residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 101

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS

As used in the entirety of this Tariff, "meter reading" and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a "meter reading." T

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 101.1

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS (continued)

receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two or more meters will not be combined except where Company's operating convenience requires the installation of two or more meters upon Customer's premises instead of one meter.

CUSTOMER RATE MIGRATION

Unless otherwise specified in the applicable rate schedule or rider, a change from one rate to another will be effective with the first full billing period following a customer's request for such change or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual Customer consumption, Company will monitor the usage of each Customer at least once quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 101.1

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS (continued)

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 101.2

TERMS AND CONDITIONS

Billing

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 102

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 8 except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.
2) Deposits may be required from all customers not meeting satisfactory credit and payment criteria. Satisfactory credit for customers will be determined by utilizing independent credit sources (primarily utilized with new customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service
3) Company may offer residential customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first six (6) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Special Terms and Conditions contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.5), Standard Rate Rider PS-TS (Sheet No. 60.1), and Standard Rate Rider PS-FT (Sheet No. 61.1).

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $100.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d). For combination gas and electric customers, the total deposit will be $260.00.
3) Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 102

TERMS AND CONDITIONS

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   a) Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b) Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service
3) Company may offer residential customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first six (6) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the requirements set forth in Section 3 of the Special Terms and Conditions **T**
contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.7), Standard Rate Rider PS-FT (Sheet **T**
No. 61.2), and the CREDITWORTHINESS section of Rate LGDS (Sheet No. 36.11). **T**

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $100.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d). For combination gas and electric customers, the total deposit will be $260.00.
3) Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

RESIDENTIAL (continued)

4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d).
2) For customers not meeting the parameters of GENERAL ¶ 2, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

RESIDENTIAL (continued)

4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d).
2) For customers not meeting the parameters of GENERAL ¶ 2, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during the customer's budget year. If actual usage indicates the customer's account will not be current with the final payment in the customer's budget year, the customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer's next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the Plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during the customer's budget year. If actual usage indicates the customer's account will not be current with the final payment in the customer's budget year, the customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer's next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the Plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 104
Canceling P.S.C. Gas No. 10, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

a PPL company

Mailed **4/14/16** for Account # **3000-4444-4444**

AMOUNT DUE	DUE DATE
$80.31	5/8/16

Account Name: JOHN SMITH
Service Address: 100 Kensington Place Ln
PLEASUREVILLE KY

Online Payments: lge-ku.com
Telephone Payments: 502-589-1444, press 1-2-3
24 hours a day; $2.25 fee
Customer Service: 502-589-1444
M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway
Louisville, KY 40202
M-F, 8am-5pm ET

Next read will occur 5/11/16 - 5/13/16 (Meter Read Portion 08)

BILLING SUMMARY

Previous Balance	261.00
Payment(s) Received	-261.00
Balance as of 4/13/16	**$0.00**
Current Gas Charges	79.52
Current Taxes and Fees	0.79
Total Current Charges as of 4/13/16	**$80.31**
Total Amount Due	**$80.31**

CURRENT USAGE

GAS	
Meter Reading Information	**Meter # 563885**
Actual (R) ccf Reading on 4/13/16	8734
Previous (R) ccf Reading on 3/14/16	8657
Current ccf Usage	77
Meter Multiplier	1
Metered ccf Usage	**77**

CURRENT CHARGES

GAS	**Rate:** Residential Gas Service
Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 77 ccf)	20.34
Gas Supply Component ($0.49951 x 77 ccf)	38.46
Weather Normalization Adjustment ($0.26419 x 12.964 ccf)	3.43
Gas DSM ($0.01311 x 77 ccf)	1.01
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$79.52**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By **5/8/16**	**$80.31**
After Due Date, Pay This Amount:	**$82.74**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-4444-4444**
Service Address: 100 Kensington Place Ln

a PPL company
PO Box 9001960
Louisville, KY 40290-1960

#926190004 2#

JOHN SMITH
100 KENSINGTON PLACE LN
PLEASUREVILLE, KY 40057-1000

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DATE OF ISSUE: March 30, 2016
DATE EFFECTIVE: April 29, 2016
ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

a PPL company

Mailed **4/14/16** for Account # **3000-4444-4444**

AMOUNT DUE	DUE DATE
$80.31	5/8/16

Account Name: JOHN SMITH
Service Address: 100 Kensington Place Ln
PLEASUREVILLE KY

Online Payments: lge-ku.com
Telephone Payments: 502-589-1444, press 1-2-3
24 hours a day; $2.25 fee
Customer Service: 502-589-1444
M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway
Louisville, KY 40202
M-F, 8am-5pm ET

Next read will occur 5/11/16 - 5/13/16 (Meter Read Portion 08)

BILLING SUMMARY

Previous Balance	261.00
Payment(s) Received	-261.00
Balance as of 4/13/16	**$0.00**
Current Gas Charges	79.52
Current Taxes and Fees	0.79
Total Current Charges as of 4/13/16	**$80.31**
Total Amount Due	**$80.31**

CURRENT USAGE

GAS	
Meter Reading Information	**Meter # 563885**
Actual (R) ccf Reading on 4/13/16	8734
Previous (R) ccf Reading on 3/14/16	8657
Current ccf Usage	77
Meter Multiplier	1
Metered ccf Usage	**77**

CURRENT CHARGES

GAS	**Rate:** Residential Gas Service
Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 77 ccf)	20.34
Gas Supply Component ($0.49951 x 77 ccf)	38.46
Weather Normalization Adjustment ($0.26419 x 12.964 ccf)	3.43
Gas DSM ($0.01311 x 77 ccf)	1.01
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$79.52**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By **5/8/16**	**$80.31**
After Due Date, Pay This Amount:	**$82.74**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-4444-4444**
Service Address: 100 Kensington Place Ln

#926190004 2#

JOHN SMITH
100 KENSINGTON PLACE LN
PLEASUREVILLE, KY 40057-1000

a PPL company
PO Box 9001960
Louisville, KY 40290-1960

01030005555550000000111850000001085900000000000023

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

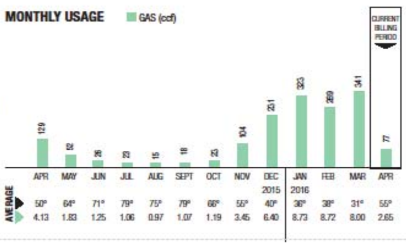
P.S.C. Gas No. 10, First Revision of Original Sheet No. 104.1
Canceling P.S.C. Gas No. 10, Original Sheet No. 104.1

TERMS AND CONDITIONS
Bill Format

Page 2 — Account # **3000-4444-4444**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**56°**	**52°**
Number of Days Billed	30	28
Avg. Gas Charges per Day	**$2.85**	**$4.13**
Avg. Gas Usage per Day (ccf)	2.57	4.61



TAXES & FEES

Franchise Fee-Pleasureville	0.79
Total Taxes and Fees	**$0.79**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $2.43

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: March 30, 2016
DATE EFFECTIVE: April 29, 2016
ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

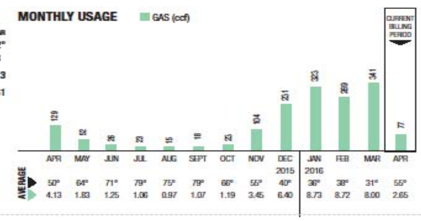
P.S.C. Gas No. 11, Original Sheet No. 104.1

TERMS AND CONDITIONS
Bill Format

Page 2 — Account # **3000-4444-4444**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**56°**	**52°**
Number of Days Billed	30	28
Avg. Gas Charges per Day	**$2.85**	**$4.13**
Avg. Gas Usage per Day (ccf)	2.57	4.61



TAXES & FEES

Franchise Fee-Pleasureville	0.79
Total Taxes and Fees	**$0.79**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $2.43

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 104.2
Canceling P.S.C. Gas No. 10, Original Sheet No. 104.2

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed **4/8/16** for Account # **3000-5555-5555**

AMOUNT DUE	DUE DATE
$107.65	5/1/16

Account Name: JOHN SMITH
Service Address: 100 Cassidy Ln
LOUISVILLE KY

Online Payments: lge-ku.com
Telephone Payments: 502-589-1444, press 1-2-3
24 hours a day; $2.25 fee
Customer Service: 502-589-1444
M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway
Louisville, KY 40202
M-F, 8am-5pm ET

Next read will occur 5/4/16 - 5/6/16 (Meter Read Portion 03)

BILLING SUMMARY

Previous Balance	185.14
Payment(s) Received	-185.14
Balance as of 4/7/16	**$0.00**
Current Electric Charges	54.03
Current Gas Charges	53.62
Total Current Charges as of 4/7/16	**$107.65**
Total Amount Due	**$107.65**

CURRENT USAGE

ELECTRIC

Meter Reading Information	Meter # 700000
Actual (R) kWh Reading on 4/7/16	58526
Previous (R) kWh Reading on 3/9/16	58072
Current kWh Usage	454
Meter Multiplier	1
Metered kWh Usage	**454**

GAS

Meter Reading Information	Meter # 600000
Actual (R) ccf Reading on 4/7/16	2704
Previous (R) ccf Reading on 3/9/16	2658
Current ccf Usage	46
Meter Multiplier	1
Metered ccf Usage	**46**

CURRENT CHARGES

ELECTRIC — Rate: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 454 kWh)	36.67
Electric DSM ($0.00520 x 454 kWh)	2.36
Electric Fuel Adjustment ($0.00224 x 454 kWh)	1.02
Environmental Surcharge (5.860% x $50.80)	2.98
Home Energy Assistance Fund Charge	0.25
Total Charges	**$54.03**

GAS — Rate: Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 46 ccf)	12.15
Gas Supply Component ($0.49951 x 46 ccf)	22.98
Weather Normalization Adjustment ($0.26419 x 6.093 ccf)	1.61
Gas DSM ($0.01311 x 46 ccf)	0.60
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$53.62**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By **5/1/16**	**$107.65**
After Due Date, Pay This Amount:	**$110.91**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-5555-5555**
Service Address: 100 Cassidy Ln

#926190005 1#

JOHN SMITH
100 CASSIDY LN
LOUISVILLE, KY 40229-1000

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

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DATE OF ISSUE: March 30, 2016
DATE EFFECTIVE: April 29, 2016
ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 104.2

TERMS AND CONDITIONS
Bill Format

LG&E
a PPL company

Mailed **4/8/16** for Account # **3000-5555-5555**

AMOUNT DUE	DUE DATE
$107.65	5/1/16

Account Name: JOHN SMITH
Service Address: 100 Cassidy Ln
LOUISVILLE KY

Online Payments: lge-ku.com
Telephone Payments: 502-589-1444, press 1-2-3
24 hours a day; $2.25 fee
Customer Service: 502-589-1444
M-F, 7am-7pm ET
Walk-in Center: 820 W. Broadway
Louisville, KY 40202
M-F, 8am-5pm ET

Next read will occur 5/4/16 - 5/6/16 (Meter Read Portion 03)

BILLING SUMMARY

Previous Balance	185.14
Payment(s) Received	-185.14
Balance as of 4/7/16	**$0.00**
Current Electric Charges	54.03
Current Gas Charges	53.62
Total Current Charges as of 4/7/16	**$107.65**
Total Amount Due	**$107.65**

CURRENT USAGE

ELECTRIC

Meter Reading Information	Meter # 700000
Actual (R) kWh Reading on 4/7/16	58526
Previous (R) kWh Reading on 3/9/16	58072
Current kWh Usage	454
Meter Multiplier	1
Metered kWh Usage	**454**

GAS

Meter Reading Information	Meter # 600000
Actual (R) ccf Reading on 4/7/16	2704
Previous (R) ccf Reading on 3/9/16	2658
Current ccf Usage	46
Meter Multiplier	1
Metered ccf Usage	**46**

CURRENT CHARGES

ELECTRIC — Rate: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 454 kWh)	36.67
Electric DSM ($0.00520 x 454 kWh)	2.36
Electric Fuel Adjustment ($0.00224 x 454 kWh)	1.02
Environmental Surcharge (5.860% x $50.80)	2.98
Home Energy Assistance Fund Charge	0.25
Total Charges	**$54.03**

GAS — Rate: Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 46 ccf)	12.15
Gas Supply Component ($0.49951 x 46 ccf)	22.98
Weather Normalization Adjustment ($0.26419 x 6.093 ccf)	1.61
Gas DSM ($0.01311 x 46 ccf)	0.60
Gas Line Tracker	2.53
Home Energy Assistance Fund Charge	0.25
Total Charges	**$53.62**

Please return only this portion with your payment. Make checks payable to LG&E and write your account number on your check.

Amount Due By **5/1/16**	**$107.65**
After Due Date, Pay This Amount:	**$110.91**
Winterhelp Donation:	
Total Amount Enclosed:	

Account # **3000-5555-5555**
Service Address: 100 Cassidy Ln

#926190005 1#

JOHN SMITH
100 CASSIDY LN
LOUISVILLE, KY 40229-1000

LG&E
a PPL company
PO Box 9001960
Louisville, KY 40290-1960

010300055555550000000111850000001085900000000000023

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, First Revision of Original Sheet No. 104.3
Canceling P.S.C. Gas No. 10, Original Sheet No. 104.3

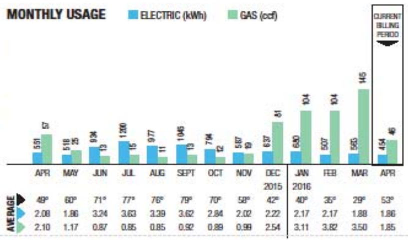
TERMS AND CONDITIONS
Bill Format

Page 2 Account # **3000-5555-5555**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	53°	49°
Number of Days Billed	29	29
Avg. Electric Charges per Day	**$1.86**	**$2.08**
Avg. Gas Charges per Day	**$1.85**	**$2.10**
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97

MONTHLY USAGE



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.26

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: March 30, 2016
DATE EFFECTIVE: April 29, 2016
ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 104.3

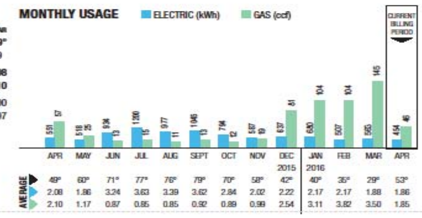
TERMS AND CONDITIONS
Bill Format

Page 2 Account # **3000-5555-5555**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	53°	49°
Number of Days Billed	29	29
Avg. Electric Charges per Day	**$1.86**	**$2.08**
Avg. Gas Charges per Day	**$1.85**	**$2.10**
Avg. Electric Usage per Day (kWh)	15.66	19.00
Avg. Gas Usage per Day (ccf)	1.59	1.97

MONTHLY USAGE



BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.26

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY:
MRU09831700, G000000
P200.00
PF:N eB:E

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse, or to discontinue, service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least 10 days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

B. When a dangerous condition is found to exist on Customer's or Applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or Applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given 15 days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

Service will not be supplied to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a lapse in service will not be subject to

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse, or to discontinue, service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least 10 days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

B. When a dangerous condition is found to exist on Customer's or Applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or Applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given 15 days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if Applicant or Customer is indebted to Company for **T**
service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if Applicant or Customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect
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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Discontinuance of Service

disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications.

Service will not be supplied or continued to any premises if at the time of application for service Applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where Applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of the customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Discontinuance of Service

lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant **T**
to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect. Company shall have the right to transfer Final Bills between residential and commercial with residential characteristics (e.g., service supplying common use facilities of any apartment building) revenue classifications.

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amount of the service rendered, and assessment of the charges under the Unauthorized Reconnect **T**
Charge provision of Special Charges incurred by reason of the fraudulent use. **T**

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

TERMS AND CONDITIONS

Discontinuance of Service

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
   a) The existing main is of sufficient capacity to properly supply the additional customer(s);
   b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
   c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

3. Where funds were advanced in accordance with paragraph 2 for extensions into developed residential neighborhoods and notwithstanding paragraph 1, any customer that subsequently connects to the main during a ten-year period from the effective date of the main extension contract shall advance to Company a pro rata share of the cost of the extension over 100 feet per connected customer.

4. For each new year-round customer connected to an extension in accordance with paragraph 3, Company will refund to the previous applicant(s) who advanced funds an amount equal to the difference between the refundable amount advanced and the amount of the advance so determined for the new applicant.

5. Company will extend its gas mains to serve a proposed real estate subdivision provided the applicant for such extension advances to Company an amount equal to the estimated cost of the total extension. Company shall have the right to determine the length of the extension and to specify the pipe size and the location of the extension, as well as the timing of its construction.

6. For each new year-round customer actually connected to the extension within a ten-year period following the effective date of the gas main extension contract, but not to extensions or laterals therefrom, Company will refund to applicant(s) who advanced funds in accordance with paragraph 5 above an amount equal to 100 times the average unit cost per foot of extension advanced by such applicant(s); provided that such refunds shall not exceed, in the aggregate, the amount originally advanced to Company.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

TERMS AND CONDITIONS

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Louisville Gas and Electric Company

TERMS AND CONDITIONS

Gas Main Extension Rules

7. Company will install at its own expense a service pipe of suitable capacity extending from its gas main to the customer's property line beyond which point all necessary piping shall be installed by and at the expense of the customer and in a manner acceptable to Company.

8. Company will install at its own expense the necessary meter together with the regulator required to convert from medium pressure to service pressure. When a high pressure gas line is tapped to serve a customer or group of customers, Company may charge the customer or customers for the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

9. In the event Company is required to make a further extension of its mains to serve a customer, Company reserves the right to tap any extension constructed under these rules and to make connections from such additional extensions without application of the refunds referred to in paragraph 4 or 6 above.

10. The title to all extensions herein provided for, together with all necessary rights-of-way, permits and easements, shall be and remain in Company.

11. Company shall not be obligated to make service connections or to extend its gas mains in cases where such extensions or connections, in the sole judgment of Company would be infeasible, impractical, or contrary to good operating practice, or where such extensions are not in accordance with the terms of the applicable rate schedule.

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Louisville, Kentucky

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 107

TERMS AND CONDITIONS

Gas Service Restrictions

By Order dated September 5, 1973, in Case Nos. 5829 and 5839, the Public Service Commission of Kentucky authorized Company to incorporate in its gas tariff restrictions on the supply of gas service, occasioned by the inadequacy of gas supplies to meet customer demands. These restrictions have been modified from time to time by tariff filings authorized or approved by the Commission. Uncertainty as to future gas supply makes it necessary that Company continue to exercise control over the addition of gas loads to its system, as set forth in these rules.

1. **GENERAL**. Except as specifically provided in these rules, Company will not (a) initiate service to any new customer, location, or service point; (b) permit any commercial customer (including any governmental agency or institution) or any industrial customer to increase its connected load or to expand its gas requirements in any manner; or (c) permit any customer to change to another rate schedule for the purpose of obtaining a higher priority under Company's Tariff.

2. **NEW CUSTOMERS**. Until further notice, Company will accept applications for gas service to new customers as set forth below. Main extensions will be made in accordance with the Gas Main Extension Rules contained in this Tariff.

   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT**. Single family dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

3. **INCREASE IN SERVICE TO EXISTING CUSTOMERS**. Until further notice, Company will, upon application, permit increases in the connected gas load or the gas usage of commercial and industrial customers existing as of the effective date of these rules, as follows:

   (a) **ADDITIONAL SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT.** Company will permit the addition of connected gas loads under Rates RGS, VFD, CGS, DGGS, IGS, and FT. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 107

TERMS AND CONDITIONS

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   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, SGSS, and FT**. Single family **T**
   dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS,
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   IGS, SGSS, and FT. Company will have the right to limit the total connected load to a maximum **T**
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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 107.1

TERMS AND CONDITIONS

Gas Service Restrictions

(b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

4. **LOAD ADDITIONS TO BE AGGREGATED**. Limitations on new or additional gas loads as specified herein refer to the aggregate of loads added subsequent to the effective date of these rules, and not to individual increments made from time to time.

5. **VOLUMES OF GAS USAGE**. Daily and monthly volumes of gas usage may be established or increased to reflect additions of connected load or increased usage of connected load existing as of the effective date of these rules. For customers subject to curtailment under Company's Curtailment Rules, Monthly Base Period Volumes will be established or adjusted accordingly.

6. **TRANSFERS BETWEEN LOCATIONS**. Company may permit any customer to transfer his own gas entitlement from one location to another; provided, however, that transfers of service cannot be aggregated so as to exceed the limitations on connected load set forth in Paragraphs 2 and 3 above with respect to Rates RGS, VFD, CGS, DGGS, IGS, and FT.

7. **PRIORITY CONSIDERATIONS**. If at any time, Company is required to select among applicants for service as provided for in Paragraphs 2(b) or 3(b) above, it will, to the extent practicable, observe the following priorities in the order named:

   (a) Schools, hospitals and similar institutions.
   (b) Other commercial establishments.
   (c) Industrial process and feedstock uses.
   (d) Other industrial applications.

8. **LAPSE OF APPLICATIONS**. If any applicant for new or increased service under these rules is not ready to take such service within twelve (12) months from the date of application, such application shall be void. Any reapplication shall be subject to Company's rules in effect at the time thereof.

9. Applicants may make application for gas service beyond that provided for in these rules, to be initiated at such time as these rules may be terminated or modified so as to enable Company to provide the service applied for. Company will file such applications in the order of receipt and dispose of them as circumstances dictate.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 107.1

TERMS AND CONDITIONS

Gas Service Restrictions

(b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, SGSS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied. **T**

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

1. **DEFINITIONS** (for purposes of these Rules).

COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

HUMAN NEEDS: Residential and other customers whose facilities are used for residential dwellings on either a permanent or temporary basis or a facility providing critical emergency services (including, but not limited to, apartment buildings, correctional institutions, hospitals, nursing homes, assisted living facilities, hotels, motels, fire department stations, police stations, national guard facilities, and emergency response agency facilities).

INDUSTRIAL CUSTOMERS: Customers engaged primarily in a process or processes which create or change raw or unfinished materials into another form or product, including, but not limited to, the generation of electric power as further described in Rate IGS and Rate DGGS.

SMALL INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes is 10,000 Mcf or less.

LARGE INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes exceeds 10,000 Mcf.

PILOT LIGHT REQUIREMENTS: Gas used on either a continuous or intermittent basis only for the ignition of the fuel in the main burner; does not include any gas used to preheat or atomize solid or liquid fuels.

BASE PERIOD: The twelve (12) months ending on the October 31 preceding the calendar year which is the subject of the implementation of any curtailments hereunder.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 108

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

1. **DEFINITIONS** (for purposes of these Rules).

COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

HUMAN NEEDS: Residential and other customers whose facilities are used for residential dwellings on either a permanent or temporary basis or a facility providing critical emergency services (including, but not limited to, apartment buildings, correctional institutions, hospitals, nursing homes, assisted living facilities, hotels, motels, fire department stations, police stations, national guard facilities, and emergency response agency facilities).

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.1

TERMS AND CONDITIONS

Curtailment Rules

MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption (including sales and transportation volumes) during the Base Period.

AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month.

Some customers may have usage falling within more than one (1) of the above categories; as such, these customers may be required to segregate their total usage accordingly.

2. **COMBINATION OF AUTHORIZED MONTHLY VOLUMES**. Subject to a written application by a customer and acceptance thereof by Company, Company may permit any customer served through more than one point of delivery at any location, or any person, corporation or entity served with gas at more than one location, to take gas through the points or at the locations of its choosing, provided that the gas so taken will not exceed the combined Authorized Monthly Volumes applicable to such points of delivery, and provided that only volumes purchased under rate schedules subject to Pro-Rata Curtailment may be so combined. Gas taken through each individual point of delivery will be billed at the rate applicable to such point of delivery.

   The right to combine Authorized Monthly Volumes as herein described is limited to individual customers or individual persons, corporations or entities and such right will not extend to similar combinations between or among unrelated customers. Nor shall such combinations be employed by any customer for the purpose of obtaining a lower overall cost of gas.

   Provided, however, in the case of Industrial Customers provided with sales service under Rate IGS or Special Contracts, which have requested and received approval to combine Authorized Monthly Volumes, Monthly Base Period Volumes for such combined Industrial Customers must aggregate to not less than 10,000 Mcf for a twelve-month period and such combination shall be treated as a Large Industrial Customer for the purpose of implementing either Pro-Rata or Emergency Curtailment.

   For the purpose of assessment of penalties, the point of delivery will be considered on a combined basis, so that the actual combined takes will be measured against combined Authorized Monthly Volumes. It will be the responsibility of any applicant for this treatment to advise Company in writing as to the party or entity to be held accountable for the payment of such penalty.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

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TERMS AND CONDITIONS

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.2

TERMS AND CONDITIONS

Curtailment Rules

3. **PRO-RATA CURTAILMENT**. In order to meet seasonal and daily sendout requirements, to preserve underground storage deliverability, and to provide for adequate and timely underground storage injections, Company will implement pro-rata curtailment with respect to the classes of customers here listed:

   (a) All customers served under Rate AAGS.
   (b) Large Industrial Customers provided with sales service under Rate IGS or Special Contracts.

   Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

   Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts.

   During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT**. In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

   (1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

   (2) Issue Action Alerts to Pool Managers under Rider PS-TS-2 serving customers under Rider TS-2, and take similar actions applicable to transportation customers served under Special Contracts. Customers of Pool Managers that fail to comply with Action Alerts may be required to terminate service under Rider PS-TS-2 and Rider TS-2 and return to firm sales service.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 108.2

TERMS AND CONDITIONS

Curtailment Rules

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   (a) All customers served under Rate AAGS.
   (b) Large Industrial Customers provided with sales service under Rate IGS, Rate SGSS, or Special Contracts. **T**

   Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

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   (1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.3

TERMS AND CONDITIONS

Curtailment Rules

(3) Discontinue service to customers served under Rate AAGS.

(4) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS or Special Contracts for gas sales service.

(5) Once curtailment in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers.

(6) Company may request that transportation customers served under Rate FT and Special Contracts allow Company's use of customer-owned gas to supply higher priority end-use customers. Company shall negotiate compensation for such gas with any customer that complies with such request.

(7) Once curtailment of customers in level 5 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers.

(8) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network.

5. **PENALTY CHARGES**. Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment.

Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00372 dated June 30, 2015

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 108.3

TERMS AND CONDITIONS

Curtailment Rules

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00371 dated xxxx

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.4

TERMS AND CONDITIONS

Curtailment Rules

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service.

The payment of penalty charges for takes of gas in excess of Authorized Monthly Volumes or authorized quantities shall not be considered as giving any customer the right to make unauthorized takes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to Company.

Company shall return to all customers through Company's Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company's supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

DATE OF ISSUE: July 10, 2015

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 108.4

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Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(5)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.

Response:

Customer notice has been given in compliance with 807 KAR 5:001, Section 17. Notice given pursuant to 807 KAR 5:001, Section 17 satisfies the requirements of 807 KAR 5:051, Section 2.

See attached Certificate of Notice.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00371**

<u>CERTIFICATE OF NOTICE</u>

Pursuant to the Kentucky Public Service Commission's Regulation 807 KAR 5:001, Section 16(1)(b)(5), I hereby certify that I am Robert M. Conroy, Vice President, State Regulation and Rates, for Louisville Gas and Electric Company ("LG&E" or "Company"), a utility furnishing retail electric and gas service within the Commonwealth of Kentucky, which, on the 23rd day of November, 2016, filed an application with the Kentucky Public Service Commission for the approval of an adjustment of the electric and gas rates, terms, conditions and tariffs of LG&E, and that notice to the public of the issuing of the same is being given in all respects as required by 807 KAR 5:001, Section 17 and 807 KAR 5:011, Sections 8(2)(c) and 9(2), as follows:

On the 23rd day of November, 2016, the notice to the public was delivered for exhibition and public inspection at 820 West Broadway, Louisville, KY 40202 and that the same will be kept open to public inspection at said office in conformity with the requirements of 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(1)(a).

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their rates or charges, and that on the 2nd day of November, 2016, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning on November 16, 2016, a notice of the filing of LG&E's application, including its proposed rates, a copy of said notice being attached hereto as Exhibit A, and a list of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, a copy of said list being attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:001, Section 17(3)(b).

Also beginning on November 16, 2016, LG&E posted on its website a copy of the notice to the public and a hyperlink to the location on the Kentucky Public Service Commission's website where the case documents and tariff filings are available. Beginning on November 23, 2016, LG&E posted on its website a complete copy of LG&E's application in this case.

Beginning on November 23, 2016, LG&E began including a general statement explaining the application in this case with the bills for all Kentucky retail customers during the course of their regular monthly billing cycle. An accurate copy of this general statement is attached as Exhibit C. Both the notice being published in newspapers and the bill inserts being sent to customers include the web address to the online posting.

Also beginning on November 23, 2016, LG&E provided notice by certified mail to special contract customers and telecommunication carrier pole attacher-licensees.

Given under my hand this 23rd day of November, 2016.

Robert M. Conroy
Vice President, State Regulation and Rates
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of November, 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Exhibit A

Notice of the Filing

NOTICE

Notice is hereby given that, in a November 23, 2016 Application, Louisville Gas and Electric Company is seeking approval by the Public Service Commission, Frankfort, Kentucky of an adjustment of electric and gas rates and charges proposed to become effective on and after January 1, 2017.

LG&E CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS

	Current	Proposed
Basic Service Charge per Month:	$10.75	$22.00
Plus an Energy Charge per kWh:	$ 0.08639	
Infrastructure		$ 0.04790
Variable		$ 0.03681
Total		$ 0.08471

Residential Time-of-Day Energy Service - Rate RTOD-Energy

	Current	Proposed
Basic Service Charge per Month:	$10.75	$22.00
Plus an Energy Charge per kWh:		
Off-Peak Hours	$ 0.06128	$ 0.05850
On-Peak Hours	$ 0.23263	$ 0.23263

Residential Time-of-Day Demand Service - Rate RTOD-Demand

Current

Basic Service Charge per Month:	$10.75
Plus an Energy Charge per kWh:	$ 0.04565
Plus a Demand Charge per kW:	
Off-Peak Hours	$ 3.25
On-Peak Hours	$12.38

Proposed

Basic Service Charge per Month:	$22.00
Plus an Energy Charge per kWh:	$ 0.03681
Plus a Demand Charge per kW:	
Base Hours	$ 3.51
Peak Hours	$ 7.68

Determination of Pricing Periods:

Current

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October
Weekdays: Off Peak (5pm-1pm), On Peak (1pm-5pm)
Weekends: Off Peak (All Hours), On Peak (N/A)
All Other Months of November continuously through March
Weekdays: Off Peak (11am-7am), On Peak (7am-11am)
Weekends: Off Peak (All Hours), On Peak (N/A)

Proposed

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of April through October
Weekdays: Base (All Hours), Peak (1pm-5pm)

Weekends: Base (All Hours), Peak (N/A)
All Other Months of November continuously through March
Weekdays: Base (All Hours), Peak (7am-11am)
Weekends: Base (All Hours), Peak (N/A)

Volunteer Fire Department Service - Rate VFD

	Current	Proposed
Basic Service Charge per Month:	$10.75	$22.00
Plus an Energy Charge per kWh:	$ 0.08639	
Infrastructure		$ 0.04790
Variable		$ 0.03681
Total		$ 0.08471

General Service - Rate GS

Single Phase	Current	Proposed
Basic Service Charge per Month	$25.00	$31.50
Plus an Energy Charge per kWh	$ 0.09650	
Infrastructure		$ 0.06509
Variable		$ 0.03721
Total		$ 0.10230
Three Phase		
Basic Service Charge per Month	$40.00	$50.40
Plus an Energy Charge per kWh	$ 0.09650	
Infrastructure		$ 0.06509
Variable		$ 0.03721
Total		$ 0.10230

Proposed

Determination of Load

Service hereunder will be metered except when, by mutual agreement of Company and Customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption taking into account the types of equipment served.

Power Service – Rate PS

Secondary Service	Current	Proposed
Basic Service Charge per Month	$90.00	$90.00
Plus an Energy Charge per kWh	$ 0.04071	$ 0.04071
Plus a Demand Charge per kW per month of billing demand		
Summer Rate (May through September)	$18.40	$20.93
Winter Rate (All Other Months)	$15.99	$18.19

Primary Service	Current	Proposed
Basic Service Charge per Month	$200.00	$240.00
Plus an Energy Charge per kWh	$ 0.03925	$ 0.03925
Plus a Demand Charge per kW per month of billing demand		
Summer Rate (May through September)	$ 15.92	$ 18.64
Winter Rate (All Other Months)	$ 13.63	$ 15.96

Current

Where the monthly billing demand is the greater of:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or

b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Where the monthly billing demand is the greater of:
a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, or
c) if applicable, a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Time-of-Day Secondary Service Rate TODS

	Current	Proposed
Basic Service Charge per Month	$200.00	$200.00
Plus an Energy Charge per kWh	$ 0.04049	$ 0.04049
Plus a Maximum Load Charge per kW per month		
Peak Demand Period	$ 6.74	$ 7.56
Intermediate Demand Period	$ 5.10	$ 5.54
Base Demand Period	$ 4.60	$ 4.84

Current

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Time-of-Day Primary Service Rate TODP

	Current	Proposed

Basic Service Charge per Month	$300.00	$330.00
Plus an Energy Charge per kWh	$ 0.03824	$ 0.03824
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 5.26	$ 6.86
Intermediate Demand Period	$ 3.91	$ 5.03
Base Demand Period	$ 3.75	$ 3.18

Current

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or

b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or

c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or

b) the highest measured load in the preceding eleven (11) monthly billing periods, or

c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Retail Transmission Service - Rate RTS

	Current	Proposed
Basic Service Charge per Month	$1,000.00	$1,400.00
Plus an Energy Charge per kWh	$ 0.03711	$ 0.03711
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 4.85	$ 6.98
Intermediate Demand Period	$ 3.30	$ 5.12
Base Demand Period	$ 3.05	$ 1.52

Current

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or

b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or

c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or

b) the highest measured load in the preceding eleven (11) monthly billing periods, or

c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Fluctuating Load Service Rate FLS

Primary Service	**Current**	**Proposed**
Basic Service Charge per Month	$1,000.00	$ 330.00
Plus an Energy Charge per kWh	$ 0.03612	$ 0.03824
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 3.42	$ 6.30
Intermediate Demand Period	$ 2.37	$ 4.48
Base Demand Period	$ 2.37	$ 2.83

Transmission Service	**Current**	**Proposed**
Basic Service Charge per Month	$1,000.00	$1,400.00
Plus an Energy Charge per kWh	$ 0.03612	$ 0.03711
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 3.42	$ 6.41
Intermediate Demand Period	$ 2.37	$ 4.56
Base Demand Period	$ 1.62	$ 1.35

Current

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 20,000 kVA, or

b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or

c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or

b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Lighting Service - Rate LS

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
High Pressure Sodium		
452 Cobra Head, 16000 Lumen Fixture Only	$13.78	$13.78
453 Cobra Head, 28500 Lumen Fixture Only	$16.17	$16.17
454 Cobra Head, 50000 Lumen Fixture Only*	$18.61	$18.61
455 Directional, 16000 Lumen Fixture Only	$14.73	$14.73
456 Directional, 50000 Lumen Fixture Only*	$19.44	$19.44
457 Open Bottom, 9500 Lumen Fixture Only	$11.93	$11.93
Metal Halide		
470 Directional, 12000 Lumen Fixture Only	$13.81	Move to RLS
473 Directional, 32000 Lumen Fixture Only*	$19.89	$19.89
476 Directional, 107800 Lumen Fixture Only	$42.04	Move to RLS
Light Emitting Diode (LED)		
490 Cobra Head, 8179 Lumen Fixture Only	N/A	$14.62
491 Cobra Head, 14166 Lumen Fixture Only	N/A	$17.73
492 Cobra Head, 23214 Lumen Fixture Only*	N/A	$27.18
493 Open Bottom, 5007 Lumen Fixture Only	N/A	$ 9.65

	Rate Per Light Per Month	
UNDERGROUND SERVICE	**Current**	**Proposed**
High Pressure Sodium		
412 Colonial, 4Sided, 5800 Lumen Smooth Pole	$20.82	$22.30
413 Colonial, 4Sided, 9500 Lumen Smooth Pole	$21.56	$22.85
444 Colonial, 4Sided, 16000 Lumen Smooth Pole	$21.69	$24.06
415 Acorn, 5800 Lumen Smooth Pole	$21.21	$24.47
416 Acorn, 9500 Lumen Smooth Pole	$23.63	$24.42
445 Acorn, 16000 Lumen Smooth Pole	$23.63	$25.64
427 London, 5800 Lumen Fluted Pole	$36.24	$36.76
429 London, 9500 Lumen Fluted Pole	$37.15	$37.15
431 Victorian, 5800 Lumen Fluted Pole	$33.97	$36.40
433 Victorian, 9500 Lumen Fluted Pole	$36.07	$36.72
400 Dark Sky, 4000 Lumen	$25.33	$25.33
401 Dark Sky, 9500 Lumen	$25.98	$25.98
956 Victorian/London Bases - Westchester/Norfolk	$ 3.56	$ 4.63
423 Cobra Head, 16000 Lumen Smooth Pole	$27.32	$35.52
424 Cobra Head, 28500 Lumen Smooth Pole	$29.55	$38.42
425 Cobra Head, 50000 Lumen Smooth Pole*	$35.27	$45.85
439 Contemporary, 16000 Lumen Fixture Only	$17.42	$17.42
420 Contemporary, 16000 Lumen Fixture & Pole	$30.86	$37.57
440 Contemporary, 28500 Lumen Fixture Only*	$19.37	$19.37
421 Contemporary, 28500 Lumen Fixture & Pole*	$33.96	$40.07
441 Contemporary, 50000 Lumen Fixture Only*	$23.55	$23.55

422 Contemporary, 50000 Lumen Fixture & Pole*	$39.63	$43.12
Metal Halide		
479 Contemporary, 12000 Lumen Fixture Only	$15.08	Move to RLS
480 Contemporary, 12000 Lumen Fixture & Pole	$24.85	Move to RLS
481 Contemporary, 32000 Lumen Fixture Only*	$21.67	$21.67
482 Contemporary, 32000 Lumen Fixture & Pole*	$31.43	$40.61
483 Contemporary, 107800 Lumen Fixture Only	$45.01	Move to RLS
484 Contemporary, 107800 Lumen Fixture & Pole	$54.76	Move to RLS
Light Emitting Diode (LED)		
496 Cobra Head, 8179 Lumen Fixture/Pole	N/A	$53.90
497 Cobra Head, 14166 Lumen Fixture/Pole	N/A	$57.01
498 Cobra Head, 23214 Lumen Fixture/Pole*	N/A	$66.46
499 Colonial, 4Sided, 5665 Lumen Smooth Pole	N/A	$46.45

Restricted Lighting Service – Rate RLS

Availability of Service:

Current

Service under this rate schedule is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole.

Proposed

Service under this rate schedule is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS. Spot replacements will not be available for Mercury Vapor and Incandescent rate codes.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole.

Units marked with an asterisk (*) are not available for use in residential neighborhoods except by municipal authorities.

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
Mercury Vapor		
252 Cobra/Open Bottom 8000L Fixture Only	$10.25	$10.56
203 Cobra Head 13000 Lumen Fixture Only	$11.69	$12.04
204 Cobra Head 25000 Lumen Fixture Only	$14.41	$14.84
209 Cobra Head 60000 Lumen Fixture Only*	$29.46	$30.34
207 Directional 25000 Lumen Fixture Only	$16.44	$16.93
210 Directional 60000 Lumen Fixture Only*	$30.66	$31.58
201 Open Bottom 4000 Lumen Fixture Only	$ 8.77	$ 9.03

Metal Halide

471 Directional, 12000 Lumen Fixture & Wood Pole	$16.09	$16.56
474 Directional, 32000 Lumen Fixture & Wood Pole*	$22.18	$22.18
475 Directional, 32000 Lumen Fixture & Metal Pole*	$29.64	$29.64
477 Directional, 107800 Lumen Fixture & Wood Pole*	$45.23	$45.23
470 Directional, 12000 Lumen Fixture Only	Moved from LS	$13.81
476 Directional, 107800 Lumen Fixture Only*	Moved from LS	$42.04
Wood Pole		
958 Wood Pole Installed Before 3/1/2010	$11.32	$11.32
900 Wood Pole Installed Before 7/1/2004	$ 2.06	$ 2.68

	Rate Per Light Per Month	
UNDERGROUND SERVICE	**Current**	**Proposed**
High Pressure Sodium		
275 Cobra/Contemporary 16000L Fixture & Smooth Pole	$25.86	$33.62
266 Cobra/Contemporary 28500L Fixture & Smooth Pole	$28.44	$36.97
267 Cobra/Contemporary 50000L Fixture & Smooth Pole*	$32.64	$42.43
276 Coach/Acorn 5800 Lumen Fixture & Smooth Pole	$15.20	$19.76
274 Coach/Acorn 9500 Lumen Fixture & Smooth Pole	$18.26	$22.85
277 Coach/Acorn 16000 Lumen Fixture & Smooth Pole	$23.11	$24.06
279 Contemporary 120000 Lumen Fixture Only*	$45.11	$45.11
278 Contemporary 120000 Lumen Fixture & Smooth Pole*	$76.24	$76.24
417 Acorn 9500 Lumen Bronze Decorative Pole	$24.75	$25.33
419 Acorn 16000 Lumen Bronze Decorative Pole	$26.30	$26.48
280 Victorian 5800 Lumen Fixture Only	$20.41	$26.53
281 Victorian 9500 Lumen Fixture Only	$21.42	$27.85
282 London 5800 Lumen Fixture Only	$20.56	$26.73
283 London 9500 Lumen Fixture Only	$21.89	$28.46
426 London, 5800 Lumen Fixture & Pole	$34.26	$36.37
428 London, 9500 Lumen Fixture & Pole	$35.17	$35.83
430 Victorian, 5800 Lumen Fixture & Pole	$33.30	$36.01
432 Victorian, 9500 Lumen Fixture Pole	$35.41	$36.32
950 Victorian/London Bases, Old Town	$ 3.47	$ 4.51
951 Victorian/London Bases, Chesapeake	$ 3.73	$ 4.24
901 Smooth 10’ Pole	$10.82	$10.82
902 Fluted 10’ Pole	$12.91	$12.91
Mercury Vapor		
318 Cobra Head, 8000 Lumen Fixture & Pole	$18.09	$19.56
314 Cobra Head, 13000 Lumen Fixture & Pole	$19.93	$21.54
315 Cobra Head, 25000 Lumen Fixture & Pole	$23.85	$25.78
347 Cobra Head, 25000 Lumen St. of Ky. Pole	$23.84	Eliminated
206 Coach, 4000 Lumen Fixture & Pole	$13.08	$14.14
208 Coach, 8000 Lumen Fixture & Pole	$14.91	$16.12
Metal Halide		
479 Contemporary, 12000 Lumen Fixture Only	Moved from LS	$17.18
480 Contemporary, 12000 Lumen Fixture & Pole	Moved from LS	$32.31
483 Contemporary, 107800 Lumen Fixture Only*	Moved from LS	$45.01
484 Contemporary, 107800 Lumen Fixture & Pole*	Moved from LS	$58.35
Incandescent		
349 Continental Jr, 1500 Lumen Fixture & Pole	$ 9.57	$ 9.57
348 Continental Jr, 6000 Lumen Fixture & Pole	$13.93	$13.93

Lighting Energy Service - Rate LE

	Current	**Proposed**
Energy Charge per kWh:	\$0.06934	\$0.06934

Traffic Energy Service – Rate TE

Current

Basic Service Charge per Month:	\$4.00 per delivery
Energy Charge per kWh:	\$0.07871

Proposed

Basic Service Charge per Month:	\$4.00 per delivery point
Energy Charge per kWh:	\$0.08533

Availability of Service

Current

Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

Proposed

Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24 hour all day every day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, and emergency sirens.

Cable Television Attachment Charges – Rate CTAC

	Current
Attachment Charge per year for each attachment to pole:	\$7.25

Rate schedule to be renamed Pole and Structure Attachment Charges Rate PSA.

Pole and Structure Attachment Charges – Rate PSA

Company proposes numerous revisions to the terms and conditions of service in this schedule. These revisions include the expansion of the applicability of the rates, terms and conditions to all telecommunication carriers except: (1) facilities of incumbent local exchange carriers with joint use agreements with the Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. Company further proposes any telecommunication carrier who is currently permitted to make attachments to Company facilities under an existing license agreement will be required to comply with the terms of the revised Schedule PSA upon the expiration of the current term of its license agreement with LG&E. In addition, Company proposes other changes in the terms and conditions, including, but not limited to attachment charges for each linear foot of duct and Wireless Facility, the imposition of a late payment fee of three percent if the attachment customer fails to pay its bill within 60 days of the bill's issuance, that attachment customers become members in the National Joint Utilities Notification System, a detailed listing of the conditions and procedures to obtain permission to attach facilities to Company structures and to maintain and operate those attachments on LG&E structures and the conditions under which wireless facilities may be attached to Company structures. Customers who may take service under this schedule or under a license agreement with Company for the attachment to Company facilities or desire to make such attachments to Company's poles or other structures or within Company's ducts may review the proposed revisions at Company's website or other locations identified below in this notice.

Attachment Charges

$ 7.25 per year for each wireline pole attachment.

$ 0.81 per year for each linear foot of duct.

$84.00 per year for each Wireless Facility.

Electric Vehicle Supply Equipment – Rate EVSE

Monthly Charging Unit Fee	**Current**	**Proposed**
Single Charger	$176.13	$183.66
Dual Charger	$293.10	$307.43

Electric Vehicle Charging – Rate EVC

Rate	**Current**	**Proposed**
Fee Per Hour:	$2.85	$2.92

Curtailable Service Rider– Rider CSR

Primary	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$ 6.50	$ 3.67
Non-Compliance Charge Per kVA:	$16.00	$16.00
Transmission	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$ 6.40	$ 3.56
Non-Compliance Charge Per kVA:	$16.00	$16.00

Availability of Service

Current

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kVA individually. The aggregate service under CSR for Louisville Gas and Electric Company is limited to 100 MVA in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as of August 1, 2010.

Proposed

This rider shall be limited to customers served under applicable power schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to January 1, 2017. Company will not enter into contracts for additional curtailable demand, even with customers already participating in this rider, on or after January 1, 2017.

Contract Option

Current

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-

Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

Proposed

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. Customer's choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year.

Automatic Buy-Through Price

Current

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in Platts Gas Daily for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday.

Proposed

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP is the Cash Price for "Natural Gas, Henry Hub" as posted in The Wall Street Journal on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

Standard Rider for Excess Facilities – Rider EF

Customer shall pay for excess facilities by:	**Current**	**Proposed**
(a) Making a monthly Excess Facilities charge payment equal to the installed cost of the excess facilities times the following percentage:		
Percentage with No Contribution-in-Aid-of-Construction	1.32%	1.32%
(b) Making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:		
Percentage with Contribution-in-Aid-of-Construction	0.54%	0.54%

Standard Rider for Redundant Capacity Charge – Rider RC

Capacity Reservation Charge per Month:	Current (Per kW/kVA)	Proposed (Per kW/kVA)
Secondary Distribution	$1.43	$1.66
Primary Distribution	$1.26	$1.50

Economic Development Rider – Rider EDR

Company proposes the following changes to Rider EDR's Terms and Conditions:

Current

c)2)i.) Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.

Proposed

c)2)i.) Company and the existing customer will determine Customer's Existing Base Load by calculating a 12-month rolling average of measured demand.

Standard Rider for Supplemental or Standby Service – Rider SS

Contract Demand per month:	Current (Per kW/kVA)
Secondary	$13.57
Primary	$12.30
Transmission	$10.83

Proposed

Company proposes to eliminate this rider.

Electric Vehicle Supply Equipment – Rider EVSE-R

Monthly Charging Unit Fee	Current	Proposed
Single Charger	$132.49	$133.77
Dual Charger	$205.83	$207.65

Returned Payment Charge

Current Rate $10.00
Proposed Rate $10.00

Meter Test Charge

Current Rate $75.00
Proposed Rate $75.00

Disconnect/Reconnect Service Charge

Current Rate $28.00
Proposed Rate $28.00

Meter Pulse Charge

Current Rate

$15.00 per month per installed set of pulse-generating equipment

Proposed Rate

$15.00 per month per installed set of pulse-generating equipment

Meter Data Processing Charge

Current Rate $2.75 per report

Proposed

Company proposes to eliminate this charge.

Unauthorized Reconnect Charge

Proposed

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter System (AMS) meter; or
5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

Customer Deposits

Current Rate

For Customers Served Under Residential Service Rates RS,
RTOD-Energy, and RTOD-Demand: $160.00
(For Combination Electric and Gas Residential Customers the total deposit would be $260.00)
For Customers Served Under General Service Rate GS $240.00
For all other Customers not classified herein, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

Proposed Rate

For Customers Served Under Residential Service Rates RS,
RTOD-Energy, and RTOD-Demand: $160.00
(For Combination Electric and Gas Residential Customers the total deposit would be $260.00)
For Customers Served Under General Service Rate GS $240.00
For all other Customers not classified herein, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

Late Payment Charge

Current Rate

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: RS, RTOD-Energy, RTOD-Demand, VFD, and GS.

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: PS, TODS, TODP, RTS, and FLS.

Proposed Rate

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: RS, RTOD-Energy, RTOD-Demand, VFD, GS, and PSA.

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: PS, TODS, TODP, RTS, and FLS.

Environmental Cost Recovery Surcharge

Availability of Service

Current

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE.

Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS.

Proposed

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE.

Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; FLS; EVSE; and EVC.

Home Energy Assistance Program Adjustment Clause HEA

Rate

Current

$0.25 per meter per month.

Proposed

$0.25 per month.

Terms and Conditions – Customer Bill of Rights

Current

You have the right to participate in equal, budget payment plans for your natural gas and electric service.

Proposed

You have the right to participate in equal, budget payment plans for your natural gas and electric service, unless any rate or rider under which you take service explicitly states otherwise.

Terms and Conditions – General

Company Terms and Conditions

Current

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions, which shall constitute a part of all applications and contracts for service.

Proposed

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions in each rate schedule and which shall constitute a part of all applications and contracts for service.

Customer Generation

Proposed

All existing and future installations of equipment for the purpose of electric generation that is intended to run in parallel with utility service, regardless of the length of parallel operation, shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff.

Terms and Conditions – Customer Responsibilities

Application for Service

Current

A written application or contract, properly executed, may be required before Company is obligated to render electric service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

Proposed

A written, in-person, electronic, or oral application or contract, properly executed, will be required before Company is obligated to render electric service. Company may require any party applying for service to provide some or all of the following information for the party desiring service: full legal name, address, full Social Security Number or other taxpayer identification number, date of birth (if applicable), relationship of the applying party to the party desiring service, and any other information Company deems necessary for legal, business, or debt-collection purposes. Company shall have the right to reject for valid reasons any such application or contract, including the applying party's refusal to provide requested information.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

Contract Demands

Current

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company's sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on Company's system for determining Contract Demand minimum.

Proposed

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company's sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on

Company's system for determining Contract Demand minimum.

If Company or Customer terminates Customer's service under a rate schedule that contains demand charges and Customer subsequently applies to Company to reestablish service to the same premise or facility, Company must determine monthly billing demand for the reestablished service as though Customer had continuously taken service from the time of service termination through the reestablishing of service to Customer. For the purpose of determining the monthly billing demand described in the preceding sentence, the demand to be used for the period during which Customer did not take service from Company shall be the actually recorded demand, if any, for the premise or facility during that period. The preceding two sentences will not apply if Company determines, in its sole discretion, that material changes to Customer's facilities, processes, or practices justify establishing a new Contract Demand for the reestablished service.

Terms and Conditions – Company Responsibilities

Metering

Current

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

Proposed

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. Company has the right to install any meter or meters it deems in its sole discretion to be necessary or prudent to serve any customer, including without limitation a digital, automated meter reading, automated metering infrastructure, or advanced metering systems meter or meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

Firm Service

Current

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

Proposed

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide service for that load, the customer-generator must contract for such service, otherwise Company has no obligation to supply the non-firm service.

Terms and Conditions – Residential Rate Specific Terms and Conditions

Power Requirement

Current

Single-phase power service used for domestic purposes will be permitted under Residential Rate

RS when measured through the residential meter subject to the conditions set forth below:

Proposed

Single-phase power service used for domestic purposes will be permitted under Residential Rates RS, RTOD-Energy, and RTOD-Demand when measured through the residential meter subject to the conditions set forth below:

Terms and Conditions – Billing

Meter Readings and Bills

Proposed

As used in the entirety of this Tariff, "meter reading" and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a "meter reading."

Terms and Conditions – Discontinuance of Service

Current

For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

Proposed

For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered, and assessment of the charges under the Unauthorized Reconnection Charge provision of Special Charges, incurred by reason of the fraudulent use.

LG&E CURRENT AND PROPOSED GAS RATES

Residential Gas Service - Rate RGS

Current

Basic Service Charge per delivery point per month:	$13.50
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.28693

Gas Supply Cost Component	0.41142
Total Gas Charge Per 100 Cubic Feet	$ 0.69835

Proposed

Basic Service Charge per month:	$24.00 per delivery point
Plus a Distribution Charge per 100 cubic feet:	$ 0.25385

Adjustment Clauses

Adding Gas Supply Clause

Volunteer Fire Department Service – Rate VFD

Current

Basic Service Charge per delivery point per month:	$13.50
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.28693
Gas Supply Cost Component	0.41142
Total Gas Charge Per 100 Cubic Feet	$ 0.69835

Proposed

Basic Service Charge per month:	$24.00 per delivery point
Plus a Distribution Charge per 100 cubic feet:	$ 0.25385

Adjustment Clauses

Adding Gas Supply Clause

Availability of Service

Current

Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

Proposed

Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation or personal vehicle fueling shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Company's Terms and Conditions. Additionally, service for gas for use in standby electric generation and personal vehicle fueling shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers.

Firm Commercial Gas Service - Rate CGS

	Current	Proposed
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00	$ 60.00
Basic Service Charge per delivery point per month if any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00	$285.00

Current

Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.21504

	Current	Proposed
Gas Supply Cost Component	0.41142	
Total Charge Per 100 Cubic Feet	$ 0.62646	

Proposed

Plus a Distribution Charge per 100 cubic feet:		$ 0.26267

Adjustment Clauses

Adding Gas Supply Clause

Firm Industrial Gas Service - Rate IGS

	Current	Proposed
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00	$165.00
Basic Service Charge per delivery point per month if any of the customer's meters have a capacity $\geq$ 5000 cf/hr:	$180.00	$750.00

Current

Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.22779	
Gas Supply Cost Component	0.41142	
Total Charge Per 100 Cubic Feet	$ 0.63921	

Proposed

Plus a Distribution Charge per 100 cubic feet:		$ 0.21929

Adjustment Clauses

Adding Gas Supply Clause

As-Available Gas Service – Rate AAGS

	Current	Proposed
Basic Service Charge per delivery point per month:	$400.00	$500.00

Current

Plus a Charge Per Mcf:		
Distribution Cost Component	$ 0.7009	
Gas Supply Cost Component	4.1142	
Total Charge Per Mcf	$ 4.8151	

Proposed

Plus a Distribution Charge per Mcf:		$ 1.0644

Adjustment Clauses

Adding Gas Supply Clause

Availability of Service

Current

This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

Proposed

This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the provisions of this rate schedule.

Special Terms and Conditions

Added the following: Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

Terms and Conditions

Removed this section.

PROPOSED NEW STANDARD RATE SGSS
Substitute Gas Sales Service

Applicability: Required for any commercial or industrial customer (as defined in Rates CGS and IGS) physically connected to the facilities of any other provider (including the Customer itself) of natural gas or other gaseous fuels. If such Customer desires to continue to receive natural gas service from Company and/or declines to allow Company to remove Company's facilities previously used to provide natural gas service to Customer, then Customer shall be obligated to take service under Rate SGSS.
Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule. Company may decline to serve customers using gas to generate electricity in standby or other applications under this rate schedule.

Proposed Rates
For commercial customers, the following charges shall apply:

Basic Service Charge per month:	$285.00 per delivery point
Plus a Demand Charge:	$6.27 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.3767 per Mcf delivered

For industrial customers, the following charges shall apply:

Basic Service Charge per month:	$750.00 per delivery point
Plus a Demand Charge:	$10.90 per Mcf of Monthly Billing Demand
Plus a Distribution Charge:	$0.2992 per Mcf delivered

Monthly Billing Demand is the greater of (1) the Maximum Daily Quantity ("MDQ"), or (2) the highest daily volume of gas delivered during the current month or the previous eleven (11) monthly billing periods. MDQ is the quantity of firm daily gas Company is obligated to provide; all service in excess of MDQ is interruptible. Customer and Company may agree on MDQ; absent agreement, MDQ is the highest daily volume used by Customer during the twelve (12) months prior to the date that Customer began receiving natural gas from another supplier with which Customer is physically connected; if that is not available, MDQ is the Customer's average daily use for the highest month's gas use in the twelve (12) months prior to the date that Customer began receiving natural gas from another supplier with which Customer is physically connected; MDQ cannot exceed 5,000 Mcf/day. The maximum hourly volume that Company shall be obligated to deliver to Customer shall not exceed 1/16th of MDQ.

Minimum Bill: All charges under the rate schedule, including, but not limited to, the basic service charge, the monthly demand charge, any volumetric charges, and any adjustment clauses.

Customer responsible for costs of necessary facilities: Customer will need to provide at its own expense or reimburse Company for certain facilities described in the proposed tariff sheets, including remote metering equipment and the cost of its installation, backflow protection devices and/or flow control equipment as may be required in sole discretion of Company, any modifications of Customer's piping in order to facilitate the installation and operation of such remote metering or other facilities determined to be necessary by Company, and any electric and telephone service needed for remote metering.

Contract Required for Service: Service under Rate SGSS may require a written contract between Customer and Company setting forth specific arrangements. The minimum term for service shall be for a period of one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary.

Numerous conforming text changes have been made throughout the tariff by inserting SGSS in sections including Demand Side Management Adjustment Clause and Terms and Conditions.

Firm Transportation Service (Transportation Only) Rate FT

	Current	Proposed
Administrative Charge per delivery point per month:	$550.00	$550.00
Distribution Charge Per Mcf	$ 0.4302	$ 0.4428
Utilization Charges for		
Daily Imbalances:		
Daily Demand Charge	$ 0.1608	$ 0.1608
Daily Storage Charge	0.1833	0.2785
Utilization Charge Per Mcf	$ 0.3441	$ 0.4393

Availability of Service

Current

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Proposed

Transportation service hereunder will be subject to the provisions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Adjustment Clauses

Adding Gas Line Tracker

Special Terms and Conditions

Added the following:

1. Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. 4. The maximum hourly volume that the Company shall be obligated to deliver shall not exceed $1/24^{th}$ of the MDQ. 10. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data.

Terms and Conditions

Removed this section.

Distribution Generation Gas Service - Rate DGGS

	Current	Proposed
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00	$165.00
Basic Service Charge per delivery point per month if any of the customer's meters have a capacity $\geq$ 5000 cf/hr:	$180.00	$750.00
Demand Charge Per 100 Cubic Feet of Monthly Billing Demand	$ 1.1263	$ 1.08978

Current

Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.03329
Gas Supply Cost Component	0.41142
Total Charge Per 100 Cubic Feet	$ 0.44471

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

Proposed

Plus a Distribution Charge per 100 cubic feet: $ 0.02992

The total monthly minimum bill shall be the sum of the minimum Demand Charge and the Basic

Service Charge.
Adjustment Clauses
Adding Gas Supply Clause
Special Terms and Conditions
Added the following: Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.
Terms and Conditions
Removed this section.

PROPOSED NEW STANDARD RATE LGDS
Local Gas Delivery Service

Applicability: Available to any party contracting with Company to provide firm transportation service of local gas (including landfill gas, bio-gas, synthetic gas, and locally produced natural gas). Customer shall request Company to utilize its system to transport, by displacement, such local gas to the Delivery Point. Company shall not be required to install any facilities of any kind to serve a Customer under Rate LGDS, but may do so at Customer's expense. Company shall not be obligated to extend its mains to facilitate service. Company's "Gas Main Extension Rules" shall not apply to Rate LGDS.

Company and Customer shall enter into an Interconnect Facility Agreement covering matters related to the Interconnect Facility, including, but not limited to, any cost reimbursement provisions. Company shall own and operate the Interconnect Facility, such Interconnect Facility being designed and constructed according to Company's specifications. Company shall own and install facilities downstream of the Interconnect Facility required to connect the Interconnect Facility to Company's mainline gas system. Company shall be reimbursed by Customer for the costs of such downstream facilities and their installation as well as the costs to construct, operate, and maintain the Interconnect Facility. Customer may be required by Company to provide adequate surety to cover the costs incurred by Company related to either the Interconnect Facility or the related downstream facilities. The outlet of the Interconnect Facility shall be the Receipt Point.

Customer must warrant that all gas transported under Rate LGDS shall be consumed within the Commonwealth of Kentucky. Absent that warrant, Company's transportation service shall be deemed interstate service and may only be provided pursuant to authorization from the Federal Energy Regulatory Commission ("FERC") and subject to the terms and conditions of Company's Statement of Operating Conditions as filed with FERC. Customer shall not be allowed to combine interstate services with intrastate services. Only one service, either interstate service or intrastate service, shall apply to a Receipt Point.

Character of Service: Transportation service under Rate LGDS is firm from the Receipt Point to the Delivery Point. The Delivery Point shall be a pool operating under either Rider PS-TS-2 or Rider PS-FT. Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Company will provide service to meet imbalances only on an as-available basis.

Company shall not be obligated to deliver gas to the Delivery Point in excess of the Maximum Daily Quantity ("MDQ"). Customer and Company shall mutually agree to establish the level of the MDQ; provided, however, that the MDQ shall not be less than 50 Mcf/day. Company's obligation to provide firm natural gas transportation service shall be limited to the MDQ.

Proposed Rates

Administrative Charge per month: $550.00 per Receipt Point

Plus a Basic Service Charge per month: $1,310.00 per Receipt Point

Plus a Demand Charge: $2.57 per Mcf of Monthly Billing Demand

Plus a Distribution Charge: $0.0388 per Mcf of Net Nominated Volumes at the Delivery Point

The Monthly Billing Demand shall be the greater of (1) the MDQ, or (2) the highest daily volume of gas delivered to the Delivery Point during the current month or the previous eleven (11) monthly billing periods.

MDQ, Nominations, and Nominated Volumes: The MDQ shall represent the maximum volume which Customer shall be entitled to nominate and Company shall be obligated to deliver to the Delivery Point.

As further described below, Customer shall specify to Company the daily volumes of gas to be received at the Receipt Point (the "Gross Nominated Volume"). From such Gross Nominated Volume shall be deducted an allowance for Company's system average LAUFG expressed as a percentage and based on historical levels. Effective November 1, 2016, such LAUFG percentage is 2.69%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to Customer at least thirty (30) days prior to such November 1.

Local Gas Flow Orders: Company shall have the right to issue a Local Gas Flow Order ("LGFO"). Customer shall be responsible for complying with the directives contained in the LGFO. Unauthorized under-deliveries or over-deliveries during the effectiveness of an LGFO shall be subject to an LGFO Charge per Mcf for each Mcf of unauthorized under-deliveries or over-deliveries, as applicable. Customer shall be subject to the LGFO Charge on the day for which the LGFO was violated, plus the applicable Utilization Charge for Daily Imbalances ("UCDI") charges and any other charges under Rate LGDS for such unauthorized under-deliveries or over-deliveries that occur. The LGFO Charge per Mcf shall be equal to $15.00 plus the higher of either (a) the daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the LGFO was violated, or (b) the daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the LGFO was violated. Such LGFO Charge shall be in addition to any other charges under Rate LGDS.

Imbalances: Company shall calculate on a daily and monthly basis Customer's imbalance resulting from the difference between Customer's Gross Nominated Volume in Mcf for receipt by Company at the Receipt Point and the Metered Receipts of gas in Mcf from Customer at the Receipt Point based on a formula described in detail in the proposed tariff.

The Utilization Charge for Daily Imbalances is the sum of the following:

Daily Demand Charge: $0.1608 per Mcf

Daily Storage Charge:	0.2785
Utilization Charge for Daily Imbalances:	$0.4393 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges under Rate LGDS. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed the +/- 5% unless an LGFO has been issued. If an LGFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the LGFO directive. Customers not in violation of the LGFO directive, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas under this proposed schedule.

Cash-Out Provision for Monthly Imbalances: Over- and under-deliveries of gas are cashed out on a monthly basis pursuant to a formula described in detail in the proposed tariff.

Remote metering: Customer shall reimburse Company for the cost of installing remote metering equipment, including any modifications to Company facilities required in order to facilitate the functioning of the remote metering.

Gas Quality: The proposed rate schedule sets forth detailed gas quality specifications which any gas delivered by Customer under Rate LGDS must meet before being accepted by Company into its gas system.

Creditworthiness: Company may require Customer to maintain an irrevocable letter of credit, cash prepayment, or such other financial instrument satisfactory to Company ("credit support") to assure Customer's performance of its obligations. The amount of the credit support shall not exceed two twelfths (2/12) of Customer's estimated annual bill.

Contract required: Service under Rate LGDS shall be performed under a written contract between Customer and Company, which shall be for a period of one (1) year or through the following October 31, whichever period is shorter. Company may require that a contract be executed for a longer initial term when deemed necessary by the size of MDQ or other special circumstances. After the initial term, service hereunder shall extend from year to year (from November 1 through October 31, the Contract Year.

Sales tax: Customer hereby agrees to reimburse Company for all Kentucky sales tax, if any, assessed on the charges of Rate LGDS.

Company has made numerous conforming text changes throughout the tariff inserting LGDS in places including Terms and Conditions.

RIDER TS-2
Gas Transportation Service/Firm Balancing Service Rider

Current Rate

Administrative Charge: $550.00 per Delivery Point per month.

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.1504	$2.2779	$0.7009
Pipeline Supplier's Demand Component	0.8392	0.8392	0.8392
Total	$2.9896	$3.1171	$1.5401

Proposed Rate

Administrative Charge per month: $550.00 per Delivery Point

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.6267	$2.1929	$1.0644
Pipeline Supplier's Demand Component	0.8392	0.8392	0.8392
Total	$3.4659	$3.0321	$1.9036

Availability of Service

Current:

In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Proposed

In addition, transportation service hereunder will be subject to the provisions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Special Terms and Conditions

Added the following:

1. Service under this rider will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. 3. The maximum hourly volume that the Company shall be obligated to deliver shall not exceed 1/24th of the MDQ. 8. Customer shall enter into a Website Subscriber Agreement if Customer desires to access telemetry data.

Terms and Conditions

Removed this section.

Gas Meter Pulse Service Rider GMPS

Monthly Charge per gas meter pulse generator	Current	Proposed
For Customers Served Under Rate Schedule FT and Rider TS-2:	$ 7.17	$ 7.17
For Customers Not Served Under Rate Schedule FT and Rider TS-2:	$24.34	$24.34

Special Terms and Conditions

Added the following: Service under this rate schedule will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

Terms and Conditions

Removed this section.

RIDER PS-TS-2

Pooling Service Rider to Rider TS-2

	Current	Proposed
PS-TS-2 Pool Administrative Charge:	$75.00	$75.00

Special Terms and Conditions

Removed requirement of surety bond as an acceptable financial instrument.

Added that Pool Manager shall enter into a Website Subscriber Agreement if Pool Manager desires to access telemetry data.

Pooling Service Rider to Rate FT - Rider PS-FT

	Current	Proposed
PS-FT Pool Administrative Charge:	$75.00	$75.00

Special Terms and Conditions

Removed requirement of surety bond as an acceptable financial instrument.

Added that Pool Manager shall enter into a Website Subscriber Agreement if Pool Manager desires to access telemetry data.

Excess Facilities – Rider EF

Customer shall pay for excess facilities by:	**Current**	**Proposed**
(a) Making a monthly Excess Facilities charge payment equal to the installed cost of the excess facilities times the following percentage:		
Percentage with No Contribution-in-Aid-of-Construction	1.24%	1.24%
(b) Making a one-time Contribution-in-Aid-of-Construction equal to the installed cost of the excess facilities plus a monthly Excess Facilities Charge payment equal to the installed cost of the excess facilities times the following percentage:		
Percentage with Contribution-in-Aid-of-Construction	0.47%	0.47%

Natural Gas Vehicle Service - Rider NGV

Availability of Service

Current

Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing compressed natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than the compression of natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

Proposed

Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than as natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

Current

Special Conditions

Proposed

Special Terms and Conditions

Added the following: 1. Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof. 4. Customer shall be solely responsible for the reporting and payment of all applicable federal and state motor fuel taxes including, but not limited to, any federal special fuel excise tax and any state motor fuel tax.

Terms and Conditions

Removed this section.

Gas Line Tracker – Adjustment Clause GLT

Applicability:

Current: Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

Proposed: Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, FT, SGSS, DGGS, and LGDS.

GLT Program Factors:

Current: All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS are assessed an adjustment to their applicable rate schedule that enables the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it assumes ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2014-00372.

A filing to update the projected program costs is submitted annually at least two (2) months prior to the beginning of the effective period. The filing reflects the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company submits a balancing adjustment to true up the actual costs with the projected program costs for the preceding year, effective with the first billing cycle on or after the effective date of the change.

Proposed: After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in the Company's most recent general rate case.

A filing to update the projected program costs will be submitted annually. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the current year. At the same time, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective for services rendered on and after the first day of the following month after the effective date of such change.

Rates

		Proposed	
	Current	Distribution Projects ($/delivery point)	Transmission Projects ($/Ccf)
RGS-Residential Gas Service	$ 5.14	$ 0.84	$ 0.00067
VFD-Volunteer Fire Department Service	$ 5.14	$ 0.84	$ 0.00067
CGS-Commercial Gas Service	$ 27.41	$ 4.26	$ 0.00051
IGS-Industrial Gas Service	$ 259.54	$ 48.86	$ 0.00020
AAGS-As Available Gas Service	$ 2,838.87	$ 48.86	$ 0.00020
SGSS – Substitute Gas Sales Service	N/A	$ 4.26	$ 0.00051
DGGS – Distributed Generation Gas Service	$ 0.00	$ 48.86	$ 0.00020
FT – Firm Transportation Service	N/A	N/A	$ 0.00003
LGDS – Local Gas Delivery Service	N/A	N/A	$ 0.00003

Note that the decrease between the current rates and the proposed Distribution Projects rates do not reflect reduced Gas Line Program costs; rather, LG&E is proposing to incorporate into its gas rate base revenue requirement a significant portion of Gas Line Program costs and to recover those costs going forward through increased Basic Service Charges for affected rate schedules.

LG&E proposes to add a Transmission Projects charge to Rider GLT to recover costs associated with its proposed Transmission Pipeline Modernization Program ("TPMP"). Rate FT will now be subject to Rider GLT charges because the TPMP will benefit customers using gas transmission facilities, not just those using gas distribution facilities.

Demand-Side Management Cost Recovery Mechanism – Adjustment Clause DSM

Availability of Service

Current

This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, and Firm Transportation Rate FT.

Proposed

This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Substitute Gas Sales Service Rate SGSS, and Firm Transportation Rate FT.

Weather Normalization Adjustment Clause – Adjustment Clause WNA

Current

The sales to Residential and Commercial Customers under Rate Schedules RGS and CGS shall be increased or decreased monthly by an amount hereinafter described as the Weather Normalization Adjustment (WNA).

Proposed

Applicable

The sales to Residential Customers, Volunteer Fire Departments, and Commercial Customers under Rate Schedules RGS, VFD, and CGS shall be increased or decreased monthly by an amount hereinafter described as the WNA.

Determination of WNA

Current

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the non-gas portion of the bills of all heating Customers served under Rate Schedules RGS and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

Weather Normalization Adjustment will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

Proposed

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the applicable Distribution Charges for Customers served under Rate Schedules RGS, VFD and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

WNA will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable Distribution Charge as set forth on the RGS, VFD, and CGS Rate Schedules.

Returned Payment Charge

Current Rate $10.00
Proposed Rate $10.00

Meter Test Charge

Current Rate $90.00
Proposed Rate $90.00

Disconnect/Reconnect Service Charge

Current Rate $28.00
Proposed Rate $28.00

Current

A charge of $28.00 will be made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS, IGS, and AAGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. Customers taking service under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of service.

Proposed

A charge of $28.00 will be made to cover disconnection and reconnection of gas service when discontinued for non payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Rate Schedules RGS, VFD, CGS, IGS, and AAGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. Customers taking service under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of service.

Inspection Charge
Additional Trip Charge When More Than Two are Necessary
Applicable to Rate FT, Rider TS-2, and Rider GMPS

Current Rate $150.00
Proposed Rate $150.00

Unauthorized Reconnect Charge

Proposed

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $132.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a meter.

Customer Deposits

Current Rate

For Customers Served Under
Residential Gas Service Rate RGS $100.00
(For Combination Gas and Electric Residential Customers,
the total deposit would be $260.00)
For Non-Residential Gas Customers, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

Proposed Rate

For Customers Served Under
Residential Gas Service Rate RGS $100.00
(For Combination Gas and Electric Residential Customers,
the total deposit would be $260.00)
For Non-Residential Gas Customers, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

Late Payment Charge

Current Rate

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: RGS, VFD, CGS, and IGS.
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: AAGS, FT, and DGGS.

Proposed Rate

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: RGS, VFD, CGS, IGS, and SGSS.
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges for customers served under the following Standard Rate Schedules: AAGS, FT, DGGS and LGDS.

Home Energy Assistance Program Adjustment Clause HEA

Rate

Current

$0.25 per meter per month.

Proposed

$0.25 per month.

Terms and Conditions – Customer Bill of Rights

Current

You have the right to participate in equal, budget payment plans for your natural gas and electric service.

Proposed

You have the right to participate in equal, budget payment plans for your natural gas and electric service, unless any rate or rider under which you take service explicitly states otherwise.

Terms and Conditions – General

Company Terms and Conditions

Current

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions which shall constitute a part of all applications and contracts for service.

Proposed

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions in each rate schedule and which shall constitute a part of all applications and contracts for service.

Terms and Conditions – Customer Responsibilities

Exclusive Service on Installation Connected

Current

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

Proposed

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. In the event that such Customer desires to continue to receive natural gas service from Company and/or declines to allow Company to remove Company's facilities hitherto used to provide natural gas service to Customer, then Customer shall be obligated to take service under Rate SGSS.

Terms and Conditions – Company Responsibilities

Metering

Current

The gas used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

Proposed

The gas used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. Company has the right to install any meter or meters it deems in its sole discretion to be necessary or prudent to serve any customer, including without limitation a digital, automated-meter-reading, automated meter infrastructure, or advanced-metering-systems meter or meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

Terms and Conditions – Character of Service

Heating Value

Current

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

Proposed

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot. All gas received into the system of Company from interstate pipelines shall meet the applicable quality standards of the respective interstate pipeline delivering natural gas to Company. All gas received into the system of Company from sources other than an interstate pipeline shall meet the quality standards prescribed in Local Gas Delivery Service Rate LGDS. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

Terms and Conditions – Billing

Meter Reading and Bills

Proposed

As used in the entirety of this Tariff, "meter reading" and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a "meter reading."

Terms and Conditions – Deposits

General

Current

5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Special Terms and Conditions contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.5), Standard Rate Rider PS-TS (Sheet No. 60.1), and Standard Rate Rider PS-FT (Sheet No. 61.1).

Proposed

5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the requirements set forth in Section 3 of the Special Terms and Conditions

contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.7), Standard Rate Rider PS-FT (Sheet No. 61.2), and the CREDITWORTHINESS section of Rate LGDS (Sheet No. 36.11).

Louisville Gas and Electric Company also proposes to change the text of the following electric tariffs: Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, Fluctuating Load Service Rate FLS, Lighting Service Rate LS, Restricted Lighting Service Rate RLS, Traffic Energy Service Rate TE, Special Charges, Curtailable Service Rider CSR, Temporary/Seasonal Service Rider TS, Economic Development Rider EDR, Environmental Cost Recovery Surcharge ECR, Home Energy Assistance Program Adjustment Clause HEA, and the Terms and Conditions.

Louisville Gas and Electric Company also proposes to change the text of the following gas tariffs: Residential Gas Service Rate RGS, Volunteer Fire Department Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Transportation Service Rate FT, Distributed Generation Gas Service Rate DGGS, Special Charges, Gas Transportation Service/Firm Balancing Service Rider TS-2, Gas Meter Pulse Service Rider GMPS, Pooling Service Rider PS-TS-2, Pooling Service Rate PS-FT, Natural Gas Vehicle Service Rider NGV, Gas Line Tracker GLT, Demand Side Management Cost Recovery Mechanism DSM, Weather Normalization Adjustment Clause Mechanism WNA, Home Energy Assistance Adjustment Clause HEA, and the Terms and Conditions.

Complete copies of the proposed tariffs containing the text changes and proposed rates may be obtained by contacting Louisville Gas and Electric Company at P. O. Box 32010, Louisville, Kentucky, 502-589-1444 or 1-800-331-7370, or by visiting Louisville Gas and Electric Company's website at www.lge-ku.com.

The foregoing rates reflect a proposed annual increase in electric revenues of approximately 8.5% and gas revenues of approximately 4.2% to Louisville Gas and Electric Company.

The estimated amount of the annual change and the average monthly bill to which the proposed electric rates will apply for each electric customer class is as follows:

Electric Rate Class	**Average Monthly Usage (kWh)**	**Annual $ Increase**	**Annual % Increase**	**Monthly Bill $ Increase**	**Monthly Bill% Increase**
Residential	957	42,126,429	9.54	9.65	9.54
Residential Time-of-Day	949	5,306	9.53	8.90	9.53
General Service	2,502	12,180,705	7.15	22.44	7.15
Power Service	58,692	12,665,684	7.14	364.44	7.14
Time-of-Day Secondary	242,209	5,698,088	6.75	1,283.35	6.75
Time-of-Day Primary	1,460,258	10,385,231	8.22	8,203.18	8.22
Retail Transmission	7,356,472	5,824,465	8.45	37,336.31	8.45
Fluctuating Load	No customers are currently served under this rate schedule.				
Outdoor Lights	98	1,920,228	8.21	1.85	8.21
Lighting Energy	1,675	0	0.00	0.00	0.00
Traffic Energy	286	20,580	6.76	1.89	6.76
PSA (presently CTAC)	N/A	0	0.00	0.00	0.00
Rider - CSR	N/A	1,920,271	44.30	53,340.86	44.30

The estimated amount of the annual change and the average monthly bill to which the proposed gas rates will apply for each gas customer class is as follows:

Gas Rate Class	Average Monthly Usage (Mcf)	Annual $ Increase	Annual % Increase	Monthly Bill $ Increase	Monthly Bill% Increase
Residential	5.5	10,631,026	4.96	2.99	4.96
Commercial	33.9	3,141,835	3.48	10.50	3.48
Industrial	609.4	417	0.00	0.13	0.00
As-Available	5,334.9	(71,575)	(6.65)	(994.10)	(6.65)
Firm Transportation	14,057.0	155,155	2.00	177.12	2.00
Distributed Generation	0.6	1,288	18.29	107.34	18.29
Substitute Gas Sales	247.5	41,306	215.03	3,442.20	215.03

The Company is seeking inclusion of two new projects in the Gas Line Tracker. The first is the TPMP referred to above. The second is the Gas Service Line Replacement Program. The estimated average monthly bill impact of the two new projects proposed for the Gas Line Tracker on each applicable rate schedule is as follows:

Year/ Effect	Rates RGS/VFD	Rate CGS/SGSS	Rate IGS/AAGS/DGGS	Rate FT/LGDS
2017				
$ Increase	$0.04	$0.17	$1.24	$3.67
% Increase	0.06%	0.06%	0.03%	0.04%
2018				
$ Increase	$0.31	$1.54	$19.70	$33.14
% Increase	0.52%	0.51%	0.54%	0.37%
2019				
$ Increase	$1.25	$6.15	$78.48	$137.90
% Increase	2.07%	2.04%	2.14%	1.55%

Notice is further given that a person may examine this application at the offices of Louisville Gas and Electric Company located at 820 West Broadway, Louisville, Kentucky, and may also be examined at Louisville Gas and Electric Company's website at www.lge-ku.com. A person may also examine this application at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov.

Comments regarding the application may be submitted to the Public Service Commission, by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, or by sending an email to the Commission's Public Information Officer at psc.info@ky.gov. All comments should reference Case No. 2016-00371.

The rates contained in this notice are the rates proposed by Louisville Gas and Electric Company, but the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. A person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.

Louisville Gas and Electric Company
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
502-589-1444 or 1-800-331-7370

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601
502-564-3940

Exhibit B

Listing of Newspapers Publishing Notice

List of Newspapers in LG&E Territory

Bardstown Kentucky Standard
Bedford Trimble Banner
Brandenburg Meade Messenger
Cave City Barren Progress
Edmonton Herald News
Elizabethtown News Enterprise
Glasgow Daily Times
Greensburg Record Herald
Hodgenville Larue Herald
Lagrange Oldham Era
Lebanon Enterprise
Louisville Courier Journal
Munfordville Hart County News
New Castle Henry County Local
Shelbyville Sentinel News
Shepherdsville Pioneer News
Springfield Sun
Taylorsville Spencer Magnet

Exhibit C

Customer Bill Insert
General Statement

NOTICE TO CUSTOMERS OF
LOUISVILLE GAS AND ELECTRIC COMPANY

PLEASE TAKE NOTICE that, in a November 23, 2016 Application, Louisville Gas and Electric Company ("LG&E") is seeking approval by the Kentucky Public Service Commission of an adjustment of its electric and gas rates and charges to become effective on and after January 1, 2017.

The proposed rates reflect a proposed annual increase in electric revenues of approximately 8.5% and gas revenues of approximately 4.2% to LG&E.

The estimated amount of the annual change and the average monthly bill to which the proposed electric rates will apply for each electric customer class are as follows:

Electric Rate Class	Average Usage (kWh)	Annual $ Increase	Annual % Increase	Monthly Bill $ Increase	Monthly Bill % Increase
Residential	957	42,126,429	9.54	9.65	9.54
Residential Time-of-Day Energy	949	5,306	9.53	8.90	9.53
General Service	2,502	12,180,705	7.15	22.44	7.15
Power Service	58,692	12,665,684	7.14	364.44	7.14
Time-of-Day Secondary	242,209	5,698,088	6.75	1,283.35	6.75
Time-of-Day Primary	1,460,258	10,385,231	8.22	8,203.18	8.22
Retail Transmission	7,356,472	5,824,465	8.45	37,336.31	8.45
Fluctuating Load	No customers are currently served under this rate schedule.				
Outdoor Lights	98	1,920,228	8.21	1.85	8.21
Lighting Energy	1,675	0	0.00	0.00	0.00
Traffic Energy	286	20,580	6.76	1.89	6.76
PSA (presently CTAC)	N/A	0	0.00	0.00	0.00
Rider – CSR	N/A	1,920,271	44.30	53,340.86	44.30

The estimated amount of the annual change and the average monthly bill to which the proposed gas rates will apply for each gas customer class is as follows:

Gas Rate Class	Average Usage (Mcf)	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	5.5	10,631,026	4.96	2.99	4.96
Commercial	33.9	3,141,835	3.48	10.50	3.48
Industrial	609.4	417	0.00	0.13	0.00
As-Available	5,334.9	(71,575)	(6.65)	(994.10)	(6.65)
Firm Transportation	14,057.0	155,155	2.00	177.12	2.00
Distributed Generation	0.6	1,288	18.29	107.34	18.29
Substitute Gas Sales	247.5	41,306	215.03	3,442.20	215.03

The Company is seeking inclusion of two new projects in the Gas Line Tracker. The estimated average monthly bill impact of the two new projects proposed for the Gas Line Tracker on each applicable rate schedule is as follows:

Year/Effect	Rates RGS/VFD	Rates CGS/SGSS	Rates IGS/AAGS/DGGS	Rates FT/LGDS
2017				
$ Increase	$0.04	$0.17	$1.24	$3.67
% Increase	0.06%	0.06%	0.03%	0.04%

LG&E is also proposing changes in the text of some of its rate schedules and other tariff provisions, including its terms and conditions for electric or gas service. Complete copies of the proposed tariffs containing the proposed text changes and rates may be obtained by contacting, Louisville Gas and Electric Company at 220 West Main Street, Louisville, Kentucky, 40202, 502-589-1444 or 1-800-331-7370, or by visiting LG&E's website at www.lge-ku.com.

Notice is further given that a person may examine this application at the offices of LG&E located at 820 West Broadway, Louisville, Kentucky, and may also be examined at LG&E's website at www.lge-ku.com. A person may also examine this application at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov.

Comments regarding the application may be submitted to the Public Service Commission, by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, or by sending an email to the Commission's Public Information Officer at psc.info@ky.gov. All comments should reference Case No. 2016-00371.

The rates contained in this notice are the rates proposed by LG&E, but the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. A person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.

A copy of the Notice of Filing and the proposed tariff, once filed, shall also be available for public inspection on LG&E's website at www.lge-ku.com, or through the Public Service Commission's website at http://psc.ky.gov.

Louisville Gas and Electric Company
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
502-589-1444 or 1-800-331-7370

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602
502-564-3940

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(2)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

Notice of Intent. Utilities with gross annual revenues greater than $5,000,000 shall notify the Commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.

(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.

(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention at a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

See attached.

LG&E
a PPL company

Louisville Gas and
Electric Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Vice President
T 502-627-3324
F 502-217-4985
robert.conroy@lge-ku.com

Dr. Talina R. Mathews, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

October 21, 2016

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity* – Case No. 2016-00371**

Dear Dr. Mathews:

Please take notice that Louisville Gas and Electric Company ("LG&E") intends to file on or after November 23, 2016, an application for a general adjustment in its electric and gas rates, including changes to its electric and gas tariffs, and for Certificates of Public Convenience and Necessity. This application will be supported by a fully forecasted test period ending June 30, 2018.

LG&E has contemporaneously filed a Notice of Election of Use of Electronic Filing Procedures for this proceeding. Please assign this matter a case number and style and advise us of same so that it can be incorporated in the application and supporting testimony before filing with the Commission.

Sincerely,

Robert M. Conroy

cc: Rebecca W. Goodman, Esq.
Executive Director, Office of the Attorney General
Rate Intervention Division (via electronic mail)

RECEIVED

OCT 21 2016

PUBLIC SERVICE
COMMISSION

LG&E
a PPL company

Dr. Talina R. Mathews, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Christopher M. Garrett
Director - Rates
T 502-627-3328
F 502-217-2607
chris.garrett@lge-ku.com

October 21, 2016

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity* – Case No. 2016-00371**

Dear Dr. Mathews:

Enclosed please find and accept a notice of election of use of electronic filing procedures in accordance with 807 KAR 5:001, Section 8. Louisville Gas and Electric Company intends to file on or after November 23, 2016, an application for a general adjustment in its electric and gas rates, including changes to its electric and gas tariffs, and Certificates of Public Convenience and Necessity.

Should you have any questions regarding the enclosed, please do not hesitate to contact me.

Sincerely,

Christopher M. Garrett

Christopher M. Garrett

cc: Rebecca W. Goodman, Esq.
Executive Director, Office of the Attorney General
Rate Intervention Division (via electronic mail)

RECEIVED
Notice of Election to Use Electronic Filing Procedures
Revised June 2014
OCT 21 2016
PUBLIC SERVICE
COMMISSION

NOTICE OF ELECTION OF USE OF ELECTRONIC FILING PROCEDURES
(Complete All Shaded Areas and Check Applicable Boxes)

In accordance with 807 KAR 5:001, Section 8, Louisville Gas and Electric Company gives notice of its intent to file an application for Adjustment of Electric and Gas Rates and CPCNs with the Public Service Commission no later than December 1, 2016 and to use the electronic filing procedures set forth in that regulation.

Louisville Gas and Electric Company further states that:

	Yes	No
1. It requests that the Public Service Commission assign a case number to the intended application and advise it of that number as soon as possible;	[X]	[ ]
2. It or its authorized representatives have registered with the Public Service Commission and are authorized to make electronic filings with the Public Service Commission;	[X]	[ ]
3. Neither it nor its authorized representatives have registered with the Public Service Commission for authorization to make electronic filings but will do so no later than seven days before the date of its filing of its application for rate adjustment;	[ ]	[X]
4. It or its authorized agents possess the facilities to receive electronic transmissions;	[X]	[ ]

5. The following persons are authorized to make filings on its behalf and to receive electronic service of Public Service Commission orders and any pleadings filed by any party or the Public Service Commission Staff:

Name	Electronic Mail Address
Robert M. Conroy	robert.conroy@lge-ku.com
Allyson K. Sturgeon	allyson.sturgeon@lge-ku.com
Kendrick Riggs	kendrick.riggs@skofirm.com

	Yes	No
6. It and its authorized representatives listed above have read and understand the procedures for electronic filing set forth in 807 KAR 5:001 and will fully comply with those procedures unless the Public Service Commission directs otherwise.	[X]	[ ]

Signed Robert M. Conroy

Name: Robert Conroy
Title: Vice President, State Regulation and Rates
Address: 220 West Main Street
Louisville, KY 40202
Telephone Number: 502-627-3324

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(6)(a)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.

Response:

The financial data for the forecasted period is presented in the form of pro forma adjustments to the base period.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(6)(b)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.

Response:

Forecasted adjustments have been limited to the twelve (12) months immediately following the suspension period.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(6)(c)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.

Response:

Capitalization and net investment rate base are based on a thirteen (13) month average for the forecasted period.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(6)(d)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.

Response:

LG&E acknowledges this requirement.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(6)(e)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.

Response:

LG&E acknowledges this requirement.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(6)(f)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.

Response:

See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY

Reconciliation of Capitalization and Rate Base

Line No.	Description	13 Month Average Total Company Balance	13 Month Average Electric	13 Month Average Gas
1	Rate Base Percentage (Schedule J-1.1/J-1.2)		82.58%	17.42%
2	Capitalization:			
3	Common Equity	$ 2,222,485,866		
4	Long-Term Debt	1,790,485,621		
5	Short-Term Debt	159,467,796		
6	Subtotal	$ 4,172,439,283	$ 3,445,600,360	$ 726,838,923
7	Adjustments to Capitalization:			
8	Trimble County Inventories		(5,136,394)	-
9	Investment in OVEC and Other		(1,161,821)	-
10	Environmental Compliance Plans		(1,063,859,684)	-
11	Demand Side Management Plans		(6,149,017)	-
12	Investment Tax Credits		35,287,432	38,253
13	Gas Line Tracker		-	(19,979,268)
14	Subtotal	-	(1,041,019,484)	(19,941,015)
15				
16	Total Adjusted Capitalization (Schedule J-1.1/J-1.2)	$ 4,172,439,283	$ 2,404,580,876	$ 706,897,908
17				
18	Assets per books not included in rate base:			
19	Net ARO Assets		(84,236,035)	(14,203,989)
20	Other Property and Investments	(9,884,511)	(7,203,198)	(1,519,493)
21	Cash and Temporary Investments	(5,019,790)	(4,145,343)	(874,447)
22	Accounts Receivable	(137,249,509)	(113,340,644)	(23,908,864)
23	Other Current Assets	(73,348,282)	(60,571,012)	(12,777,271)
24	Deferred Regulatory Assets	(474,755,873)	(392,053,400)	(82,702,473)
25	Other Deferred Debits	(6,960,585)	(5,748,051)	(1,212,534)
26	Subtotal	(707,218,549)	(667,297,681)	(137,199,071)
27				
28	Liabilities per books not included in rate base:			
29	Other Deferred Credits	40,575,097	4,334,964	914,447
30	Regulatory Liabilities	76,109,847	62,851,512	13,258,335
31	ARO Liabilities	177,339,133	146,446,656	30,892,477
32	Other Current Liabilities	292,008,349	241,140,495	50,867,854
33	Misc. Long-Term Liabilities	4,249,578	3,509,301	740,276
34	Accumulated Provision for Pension & Postretirement	139,964,967	115,583,070	24,381,897
35	Accumulated Deferred Income Taxes	4,438,591	3,665,389	773,203
36	Subtotal	734,685,562	577,531,386	121,828,491
37				
38	Items not included in rate base:			
39	Environmental Compliance Cash Working Capital		1,201,613	-
40				
41	Items included in rate base:			
42	Cash Working Capital Formula	86,976,746	75,842,724	9,932,409
43	Capitalization / Rate Base Allocation Differences	-	(10,924,990)	10,924,991
44	Subtotal	86,976,746	64,917,734	20,857,400
45				
46	Total Reconciliation	114,443,759	(23,646,948)	5,486,819
47				
48	Total Rate Base (Schedule B-1)	$ 4,286,883,042	$ 2,380,933,928	$ 712,384,727

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(a)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.

Response:

Please refer to the testimonies and exhibits of the following persons:

- Victor A. Staffieri
- Kent W. Blake
- Paul W. Thompson
- Daniel K. Arbough
- Adrien M. McKenzie
- David S. Sinclair
- John P. Malloy
- Lonnie E. Bellar
- Robert M. Conroy
- William Steven Seelye
- Christopher M. Garrett
- John J. Spanos

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(b)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The utility's most recent capital construction budget containing at a minimum a three (3) year forecast of construction expenditures.

Response:

See attached.

Louisville Gas and Electric Company
Case No. 2016-00371
Capital Expenditure Budget - Electric
Years 2016-2019

	Projected Capital Expenditures			
Category of Spend	**2016**	**2017**	**2018**	**2019**
Generation	255,266,930	288,079,876	304,984,409	158,934,785
Transmission	14,375,855	23,788,041	31,409,403	73,530,304
Distribution	78,372,673	98,268,155	107,374,506	112,127,822
Customer Services	5,463,514	22,736,488	55,429,625	48,906,207
IT & Other	20,687,780	18,560,600	15,980,223	15,205,714
Total	**374,166,752**	**451,433,160**	**515,178,167**	**408,704,833**

Louisville Gas and Electric
Company Case No. 2016-00371
Capital Expenditure Budget - Gas
Years 2016-2019

	Projected Capital Expenditures			
Category of Spend	**2016**	**2017**	**2018**	**2019**
Distribution	90,411,161	89,901,522	115,168,236	116,028,800
Customer Services	3,806,957	10,803,226	25,333,435	22,190,944
IT & Other	8,912,737	7,531,675	6,744,585	6,258,759
Total	**103,130,856**	**108,236,423**	**147,246,256**	**144,478,503**

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(c)
Sponsoring Witnesses: Kent W. Blake / Paul W. Thompson / Daniel K. Arbough / David S. Sinclair

Description of Filing Requirement:

A complete description, which may be filed in written testimony form, of all factors used in preparing the utility's forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.

Response:

A complete description of all factors used in preparing LG&E's forecast period, including the quantification, explanation and support for all econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels in LG&E's forecast period are contained in the written direct testimony of Daniel K. Arbough and David S. Sinclair filed with LG&E's application and are also otherwise quantified, explained and properly supported in the following documents attached to this Filing Schedule. Certain information responsive to this request is being provided under seal pursuant to a Petition for Confidential Protection.

A. Financial Planning Modeling Process	Daniel K. Arbough
B. Annual Electric Sales & Demand Forecast Process	David S. Sinclair
C. 2017 Business Plan Electric Sales Forecast	David S. Sinclair
D. Annual Natural Gas Volume Forecast Process	David S. Sinclair
E. Annual Natural Gas Sendout Process	David S. Sinclair
F. 2017 Business Plan Gas Volume Forecast	David S. Sinclair
G. Annual Generation Forecast Process	David S. Sinclair
H. 2017 Business Plan Generation and OSS Forecast	David S. Sinclair
I. Line of Business Presentations	Kent W. Blake/Paul W. Thompson

Financial Forecast Modeling Process

Table of Contents

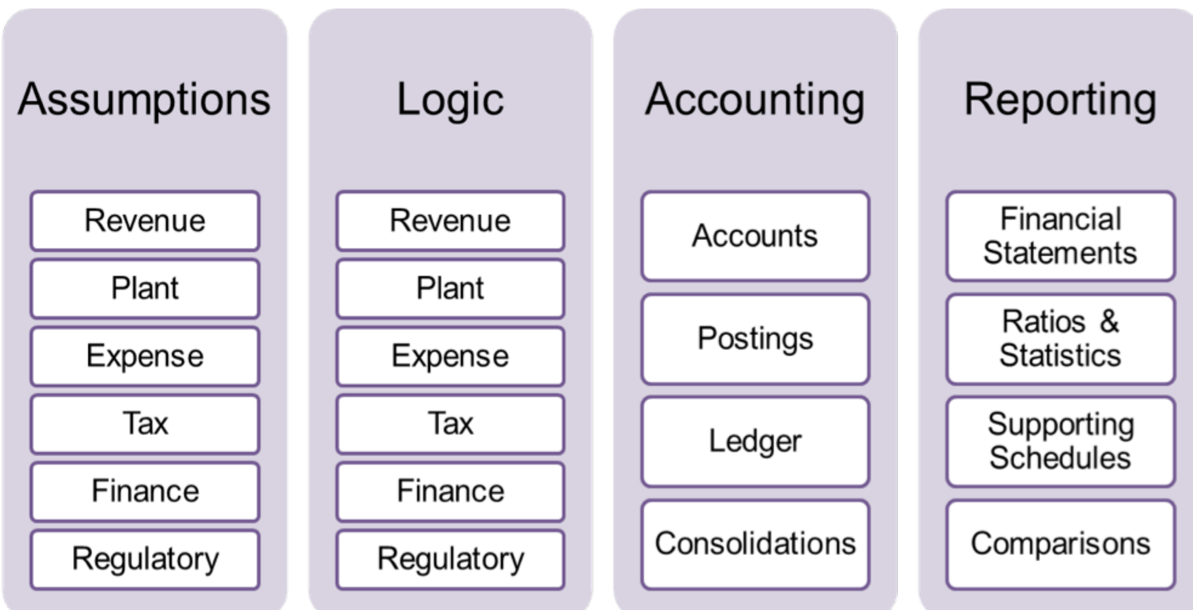
1. General

Introduction

The Financial Planning & Analysis group develops the five-year Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") and LG&E and KU Energy LLC ("LKE" or collectively "the Companies") business plan. The business plan is developed using the financial planning system, UIPlanner, an iterative model, which incorporates numerous inputs from the business as well as various formulas, algorithms and set logic. The business plan includes the projected five-year income statements, balance sheets and cash flows for the Companies.

UIPlanner (UI)

UI allows the company to manage all of the assumptions in the business plan, integrates the business logic, utilizes built in accounting controls, and produces robust analyses and reports.



[1]

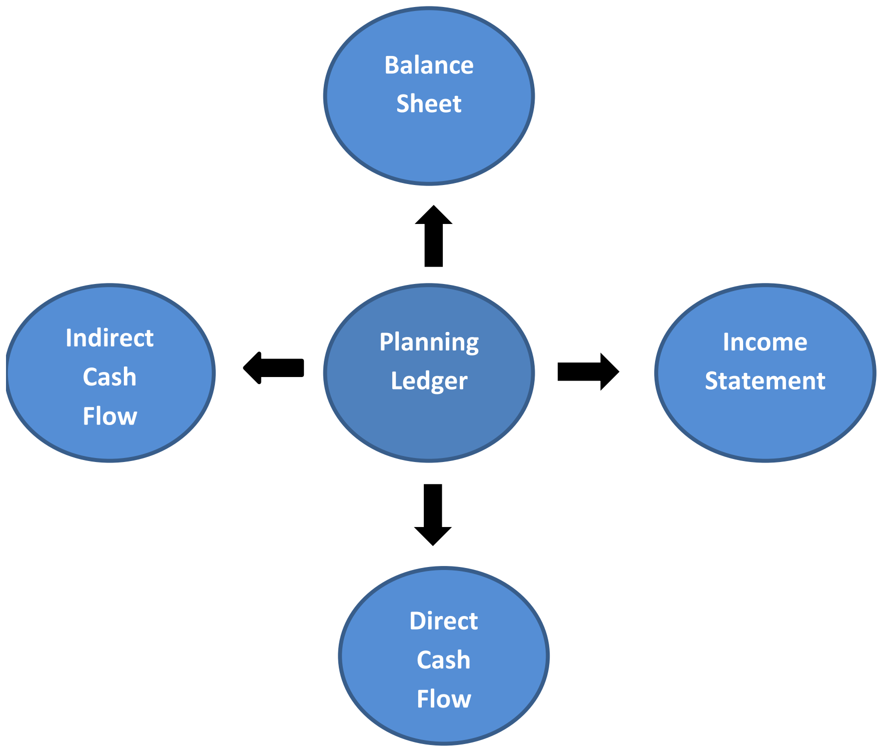
Planning assumptions are managed in UI. UI is superior to an Excel based model because it allows for sharing assumptions in a common database. UI tracks changes to assumptions and maintains a record of who made the change and when.

UI has built-in accounting capabilities, which function identical to a general ledger (see Planning Ledger flow chart below). Double-entry accounting of debits and credits is developed in UI to maintain integrity of financial statements. If a posting is not entered in UI or if one side of the debit/credit is missing, UI will produce an error message before it will produce a financial statement. Ledger accounts are organized with a configurable roll-up structure. UI also allows for combining several accounts to a summary account for consistent and concise formatting in

[1] http://utilitiesinternational.com/uiplanner-software/planning/

the production of financial statements. These summary accounts are rolled up into a high-level area (asset, direct cash, expense, indirect cash, liability, or revenue). Each account in the ledger is also associated with an indirect cash flow account which can be customized to generate a detailed cash flow statement.

Planning Ledger Flow Chart



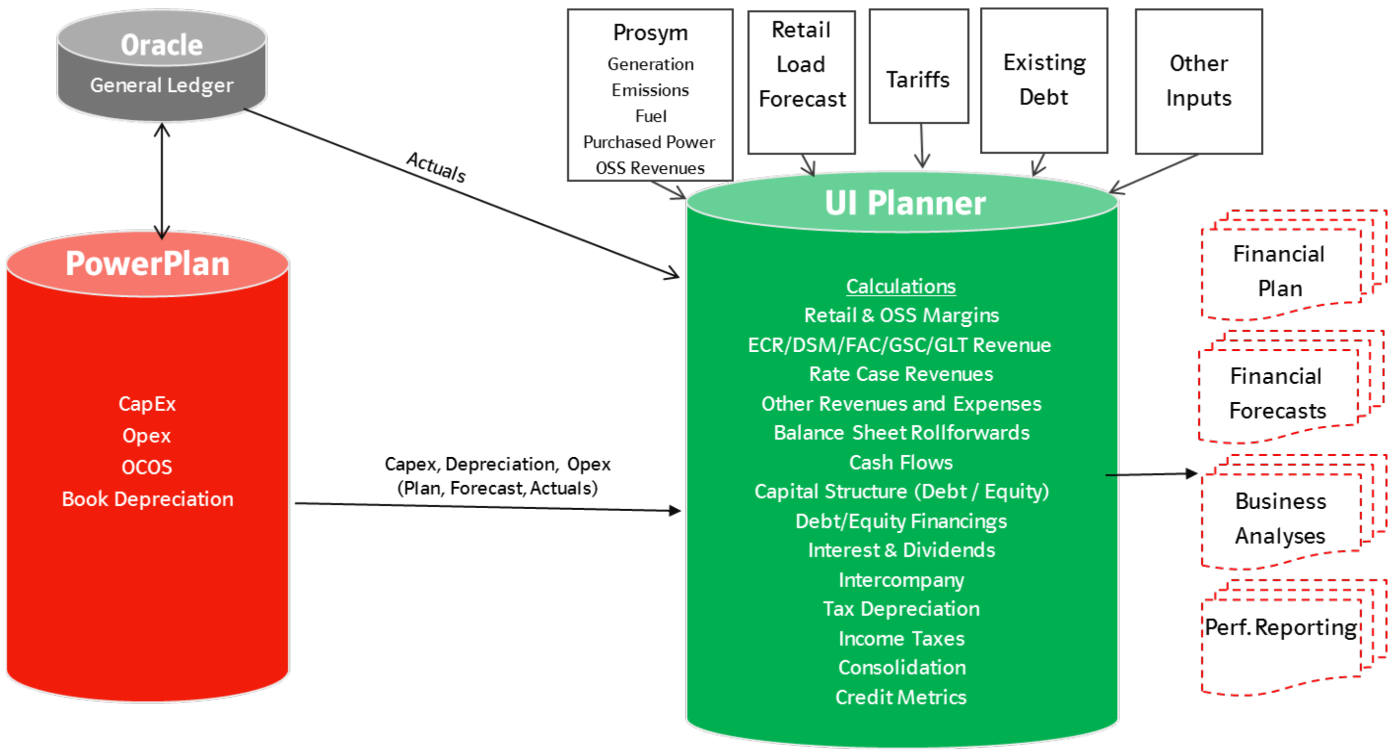
Each month actual balances are imported from the Oracle General Ledger (GL) to update UI with the latest balances and to compare the budget and revised forecast to actuals. The actuals imported into UI are compared to the trial balance in Oracle monthly to ensure completeness and accuracy.

Data in UI is entered via edit time data and housed within "cases". A collection of cases is grouped to create a "scenario". For example, the "2017 Business Plan" is a scenario in UI. After a scenario runs through the iterative process in UI, users can view the Financial Statements and other various reports in UI.

Security is specific by user in UI. When data assumptions are entered, the person entering the assumptions is tracked within UI for auditing purposes. Only certain users have the ability to edit data entry and logic assumptions. In addition, when a scenario, such as the business plan, is finalized, the scenario is locked so no further changes can be made. Only certain users have the ability to lock and unlock scenarios and cases. Logic from a case and/or scenario can be copied and utilized in additional what-if analyses. UI allows for creating and managing multiple scenarios with various planning assumptions and business logic in a transparent and efficient manner.

See the Financial Planning Software Flow Diagram below, detailing which systems provide data and other forms of inputs to UI to create the financial plan, forecast, business analysis and other management reports. This document summarizes the systems used to produce the business plan.

Financial Planning Software Flow Diagram



Budgeting Overview

LKE uses a "bottom up" budgeting approach. The process begins with the various business units preparing detailed budgets for their individual areas of responsibility, consisting of expense items, certain types of LOB managed revenues, and capital spending. The budgets prepared by the business units are reviewed and approved by LKE management. The LKE Officers ultimately approve the LKE consolidated annual budget. If any changes occur during the review and approval process, the changes are communicated to the appropriate line of business (LOB), and each LOB submits a revised budget through the same review and approval process.

Each year, LKE prepares a five-year forecast of operating revenues and expenses, which is the starting point for preparing the annual budget and the five-year business plan. Each business unit is required to create its own five-year capital and operation and maintenance (O&M) expense plan to produce an all-inclusive operating plan which is presented for review by the Officers. The five-year capital and O&M plan is developed and accumulated in PowerPlan, the Company’s corporate budgeting application. These details from PowerPlan are uploaded into the financial planning system – UI.

2. <u>Revenue and Load Forecast</u>

Retail Revenue

In order to calculate revenues, UI logic uses the load forecast and the tariffs that need to be applied to the forecast. For energy, UI multiplies megawatt hours times the energy tariff. For demand, UI calculates base, intermediate and peak demand revenue by multiplying the megawatt or kilovolt-ampere (kVA) times the demand tariff for base, intermediate and peak demand. For customer revenue, UI multiplies the number of customer times the customer charge. For base fuel revenues, UI multiplies the base fuel rate times the megawatt hour sales by jurisdiction.

The first step in preparing the operating revenues is to obtain an energy, demand and customer forecast of the projected electric and gas sales. The load forecasts are calculated on a yearly basis for each tariff. See the Annual Electric Sales and Demand Forecast Process Document, the Annual Natural Gas Volume Forecast Process Document, the Annual Natural Gas Sendout Process and associated presentations, for detailed descriptions of the assumptions and methodology used in developing the electricity and gas load forecast. The following information is uploaded into UI:

- Energy forecast for each month and year, by tariff
- Demand forecast by month and year, by tariff
- Customer count by month and year, by tariff
- Base fuel revenues forecast by month and year

Allocators are used to convert the load from tariff rate to revenue class in UI. The allocators are supplied by the Sales Analysis and Forecasting group. The previous calendar year actuals data is utilized to calculate the allocators. The calculation divides the amount of energy, demand, or customer count by revenue class by tariff divided by the total energy, demand, or customer count respectively for the entire tariff. The tariffs are entered into UI from the tariff book based on the last rate case. UI then calculates energy, demand and customer revenues by revenue class. The revenues are then posted to the income statement.

Transmission Revenue

External Transmission revenue is imported into UI from an excel spreadsheet prepared by the Transmission Policy and Tariffs department. The projected external transmission amounts are calculated as follows:

1. Network Service (the forecast multiplied by the associated rates)
    a. The volumetric forecasts are provided by the customer for 2017-2026.
    b. Volumetric forecasts are based on the summer and winter peaks provided and interpolated over a twelve month period.
    c. For the 2017 BP, the transmission rates for June 1, 2017 through May 31, 2023 were forecasted based on Attachment O of the OATT

2. Point to Point Service (Service request multiplied by the associated rates)
   a. Long term service – is based on the original transmission request, these volumes remain fixed until their expiration unless there was newer information which indicated these long term reservations would be rolled over.
   b. Short-term firm service– is projected based on annual historical revenue.
   c. For the 2017 BP, the transmission rates for June 1, 2017 through May 31, 2023 were forecasted based on Attachment O of the OATT.

The projected intercompany transmission revenue is imported into UI from PowerPlan.

The transmission rates are documented in the LG&E and KU Open Access Transmission Tariff, which is reviewed and approved by the FERC. The projected load is applied to the appropriate transmission rates to calculate the transmission revenue.

Rate Case impacts

Projected timing of filings based on financial projections are every two years for Kentucky and Virginia jurisdictions and every year for FERC Formula Rate true up.

Revenue requirements calculated in UI using expected ROE based on past rate case settlements.

Miscellaneous Revenue

Miscellaneous revenue is comprised of:

- Forfeited discounts and late payment charges
- Reconnect, gas meter and inspection charges and temporary service charges
- Rent from electric and gas property
- Other Electric and Gas revenues which include Coal resale revenues
- Solar Share Subscriptions/Capacity Charges/Energy Credits
- Solar REC revenues
- Electric Vehicle Charging Station revenues

For most of the above items, the miscellaneous revenue is calculated by utilizing the historical trends and applying an inflation factor to the next five years, which is then uploaded into UI.

The historic trend is based on the most recent three years of data. The most recent three years was selected as the sample period due to the extreme outliers occurring before that period. Three years gave an appropriate distribution of data to evaluate the account activity.

An inflation factor of 2% was utilized. The 2% is reasonable based on the average of the two-year and three-year CAGRs of the account data. Accounts with extreme outliers were excluded. An account was determined to have an outlier if the account activity varied more than 50% from one year to the next. A 2% inflation factor provided a reasonable trend for the years in the BP.

The billing of the Louisville Water Company to provide standby service at one of their pumping stations is charged every January per the contract. It is a long-term contractual amount, which assumes no escalation from one year to the next. This account was excluded from the historical trend and escalation factor analysis.

For KU, the Cable TV Attachments and the Rent received from pole attachments, property, and equipment such as transformers accounts utilize the most recent year of data and are then escalated 2%. Rent from Fiber Optic is a fixed amount yearly. No escalation is assumed and the revenue is budgeted each January.

For LG&E, the Cable TV Attachments and the Rent received from pole attachments, property, and equipment such as transformers, and Rent from Fiber Optic accounts utilize the most recent year of data and are then escalated 2%.

A coal sale is essentially revenue derived from the transportation of coal for a third party. The Company does not purchase the coal or take possession of it; the Company utilizes an existing barge contract to transport the customer's coal. The revenues are based on the contract with the customer, which incorporates costs of the barging, trucking, labor hours, maintenance, plus the profit. The Company has a contract through June 2017, past June 2017, there is a negotiated price. There is no escalation factor.

Electric Vehicle Charging Station Rental revenues during the 2017 BP were supplied from the Smart Grid Strategy group. The revenues were matched to the capital plan from customer service.

Solar RECs were calculated utilizing the forecasted generation from Gen Planning and multiplied by a rate of $12 per MWh. One MWh of generation equals one REC. The price was obtained from the Manager of Trading.

Solar Share Program budgeted revenues were obtained from Customer Services and based on their approved capital plan which has an eight phase build schedule.

3. <u>Mechanisms</u>

Background

The Kentucky Public Service Commission has adopted a series of regulatory mechanisms that reduce regulatory lag and provide for timely recovery of and a return on, in some instances, prudently incurred costs. The following represents an overview of certain key mechanisms and assumptions reflected in the business plan.

Environmental Cost Recovery (ECR)

The Utilities are entitled to recovery of operating costs and recovery of and a return on capital costs of complying with Federal Clean Air Act with a two-month lag. The first step is to calculate the total revenue requirement which involves determination of environmental rate base and operating expenses for each KPSC approved ECR project.

Within UI the revenue requirement for ECR is calculated using the following:

- The logic calculates a monthly ending rate base by adding ECR capital expenditures from the capital plan to the previous months' ending rate base; subtracting ECR depreciation for the period and increase/decrease in ECR deferred taxes calculated within UI. A return on the ending rate base is calculated using a weighted average cost of capital computed within UI using weighted average cost of debt and allowed return on equity;
- ECR Depreciation and O&M is then added to the return on rate base to calculate a total revenue requirement;
- A jurisdictional factor is computed within UI using a ratio of KY retail to total revenue and applied to the total revenue requirement to calculate a jurisdictionalized ECR Revenue Requirement;
- The model then deducts any ECR revenue recovered within the base rates to generate a net ECR revenue.

Demand Side Management (DSM)

DSM provides for concurrent recovery of DSM costs and provides incentive for implementing DSM programs, including lost revenue.

In UI, there are four components for DSM revenue:

- DSM expense as imported from PowerPlan within the Cost of Sales import
- DSM incentive revenue as calculated in UI on the eligible portion of programs
- DSM Lost sales revenue as calculated in UI using the imported lost sales volume and rates from the DSM Energy Efficiency model
- DSM Capital revenue requirement is calculated in UI by adding the capital spend imported from PowerPlan to the previous month's ending DSM rate base, adjusted for depreciation, an increase/decrease in deferred taxes. A return on the DSM rate base is

calculated using a weighted average cost of capital computed within UI using weighted average cost of debt and allowed return on equity. In addition, the depreciation and O&M expenses are added to the return on the DSM rate base to calculate the total DSM Capital Revenue Requirement.

- DSM expense, incentive revenue, and lost sales revenues are added to the capital revenue requirement to calculate the total DSM revenue requirement.

Gas Line Tracker (GLT)

Currently the GLT provides for recovery of costs associated with replacing customer service risers, replacing and installing service lines, leak mitigation, and main replacements. In addition to these items, the budget has incorporated the steel gas service line program and the transmission pipeline modernization, which the Company is requesting approval to include in the GLT mechanism.

The GLT revenue requirement is calculated in UI using the following:

- The rate base is rolled forward for identified GLT projects using capital spend and in service dates per PowerPlan as well as the calculated deferred income taxes;
- The rate of return on rate base is computed within UI using weighted average cost of debt and allowed rate of return on equity.
- GLT Depreciation, Property Tax and O&M are then added to the return on rate base to calculate a total revenue requirement;

Fuel Adjustment Clause (FAC)

The FAC mechanism allows for near-real time recovery of allowed fuel expenses.

Total fuel expense incurred consists of all generation and purchased power costs. For FAC purposes, total recoverable fuel expense includes total incurred expense reduced by the following components: non-energy components of purchased power expense; substitute generation or purchased power costs during forced outages; coal burned for OSS electric generation, company use, and unrecoverable intercompany sales. The total recoverable fuel expenses is then compared to the base fuel revenues. The over/under is booked to The Fuel Adjustment Clause.

Mechanism Revenue Calculations

For all mechanisms, except for the GLT, the total mechanism revenue requirement is divided by the total forecasted megawatt hours by electric rate code associated with each mechanism. These values are applied as a dollar per megawatt hour to calculate the revenue by electric rate code.

For GLT, the total mechanism revenue requirement is allocated to the customer class associated with GLT based on the class allocation percentages from the most recent filing.

The revenues from all mechanisms are recorded to the income statement as revenues from customers.

4. <u>Generation Forecast, Off-System Sales (OSS) and Other Cost of Sales (COS)</u>

The PROSYM application is used to calculate generation and OSS. See the annual Plan Generation Forecast Process Document and related presentations, for a detailed description of the assumptions and methodology used to calculate these inputs.

The projected data includes fuel burn, generation, purchase power, emissions, and OSS levels from an hourly dispatch model. Imported into UI is a monthly, by unit, volumes, revenues and / costs associated with off system sales, purchased power, emissions, generation, and fuel burn for the planning period.

OSS

Included in the previous rate case settlement was an OSS Tracker which results in sharing the OSS margins on a 75 percent - 25 percent basis, with 75 percent of the OSS margins being credited to customers via the Fuel Adjustment Clause.

Power Purchase Agreement

Power purchase agreement costs are based on the contracts set with the third party power producer. The amounts per the contracts are imported into UI, which is recorded on the income statement as the purchased power cost. The information uploaded into UI by month and year includes the following costs:

- Capacity and demand payments
- Energy payments, and
- Firm gas transport costs, if applicable

UI logic ensures the power purchase cost reflects the recovery of the energy and firm gas transport costs through the fuel adjustment clause and the capacity and demand cost through base rates.

Other Cost of sales (COS)

OCOS inputs come from PowerPlan and PROSYM. Off system sales, purchased power, and fuel related costs come from PROSYM, as noted above. Emissions, mechanism (DSM, ECR, ECR, GSC, and GLT), and transmission related costs come from PowerPlan.

Other electric cost of sales includes variable production consumables used by the power plants in the generation of electricity. For coal units, this includes the cost of operating environmental controls and the cost of controlling coal combustion residuals. This includes:

  - Limestone – SO_2 emission control for flue gas desulfurization (FGD) systems
  - Ammonia – NO_X emission control for selective catalytic reduction (SCR) systems
  - Hydrated Lime – SO_3 emission control for sorbent injection systems
  - Powder Activated Carbon – Hg emission control for pulse jet fabric filter systems

The individual power plant's budget coordinator, in coordination with the operations leadership team at the plant, calculates the costs. This is a function of the usage rates for the consumables utilized by each individual operating unit. This is multiplied by the unit price determined by fleet wide contracts with suppliers. Planned outages and forecasted generation levels by year are included in these assumptions for each unit.

The calculation for these consumables includes the following inputs and calculations:

Unit Price	Usage Rate	Unit Production	Conversion	Total Projected Cost
$/ton (lbs.)	lbs. /hour	MWH's by unit	$/MWH	Total $ by month and year

These costs are loaded into PowerPlan under the appropriate FERC account and then uploaded into UI and incorporated into the Income Statement.

The cost of sales items related to fuel burn, emissions and purchased power are reflected in the Cost of Electric Sales section of the Income Statement.

Gas Supply

Gas supply costs are calculated by using the gas load forecast priced out at contracted rates and market prices for open/indexed positions.

5. Operations & Maintenance (O&M) (Non-fuel)

Operations and Maintenance expenses are included as part of the Income Statement and reflect the labor and nonlabor expenditures incurred and charged to the appropriate FERC account and company location. The budget is developed in a "bottoms up" approach and is reviewed and approved by several levels of management before being entered into PowerPlan for consolidation. This information is then uploaded to UI for review and approval.

Labor Cost

The Company's current labor base is obtained from PeopleSoft annually in May. The PeopleSoft data is exported to excel where the wage increases, vacation hours, personal days, and sick time are manually added. The adjusted data is imported into PowerPlan with the labor forecast being available by mid-May. The forecast includes full-time and part-time regular employees, summarized by employee type and expenditure organization.

Updates to the forecast in PowerPlan are due in early June. This updated data is used to calculate employee benefit costs (also referred to as 'burdens' - which include costs such as pension, savings plan, medical, dental, and payroll taxes) , which will be added to the forecast by mid-June. The labor forecast is not finalized at this time and changes can be made, as required.

Non-labor Expenses

The management teams and budget coordinators throughout the lines of business areas prepare the budget for non-labor O&M expenses at the same time as the labor budget. These expenses are budgeted to the appropriate FERC account.

Planned changes in costs within accounts can be specifically escalated according to contracted changes and other volume based assumptions or expected changes in primary cost categories such as generation facilities, outages, workforce plan changes, demand-side management, and environmental costs.

- The labor rates are subject to possible adjustment pursuant to union negotiations. The rate increase assumptions are based on annual benchmarking studies performed.
- Non-labor expenses contain a general inflationary increase for assumed growth in expenses not specifically tied to contracts or fixed amounts.

6. Property Tax

Property taxes are estimated annually based on net book asset values as of December 31 of the previous year and includes several current asset balances such as; fuel inventory and materials and supplies. The expense accrual is spread evenly over twelve months while cash payments are based on historic trends, which normally results in large cash payments during the fourth quarter of a calendar year. Property tax data is imported into UI by FERC account by utility.

The primary source of data used to calculate the estimates is within the UI report labeled “KY Plant Account” report from UI Planner. The plant account assignment determines the property classification (real estate, manufacturing machinery, other tangible) and then the appropriate tax rates are applied to those balances. State and local tax rates are based on prior year settlements with an assumed increase to local tax rates of two percent per year. Property taxes related to rate mechanisms are calculated separately and manually adjusted in UI.

7. Other Income Statement Items

Other income and expense items not included above include:

- Donations – annual budget is approved by Senior Officers based on planned commitments and in support of Community and Corporate Responsibility initiatives
- Employee Recognition costs (non-safety related) – based on detailed review of historical and projected expenses for employee recognition programs under each business unit
- Non-Utility Revenues and Expenses – based on detailed review of historical and projected items, including contracted based amounts and projected increases
- Interest income and dividends received – primarily interest received which is based on the interest income from temporary cash investments. The interest rate is obtained from the Treasury department and UI calculates the monthly expected interest income based on the temporary cash investment balance.

8. Taxes

Current and Deferred Income Taxes

Income taxes are calculated using several schedules within UI. The calculation starts by utilizing the monthly pretax book income per UI's income statement. Pretax book income is then adjusted by permanent and temporary book/tax differences to derive taxable income. The book/tax differences are primarily pulled from multiple sources within UI, which include;

- tax depreciation,
- book depreciation,
- regulatory asset & liability movement,
- pensions/post-retirements,
- capitalized interest, and
- Section 199, etc.

Other book/tax differences are manually input into UI. Taxable income is multiplied by the statutory tax rates to determine current tax expense. Quarterly tax payments are derived based on current tax expense.

Deferred taxes are calculated within UI by using the temporary book/tax differences used in the current tax calculation and applying the statutory tax rates. Adjustments to deferred tax expense are made for excess deferred taxes and a basis reduction due to the Trimble County 2 investment tax credit (ITC). Additionally, the ITC amortization is manually entered into UI based on ITC amortization schedules maintained by the Tax department.

9. Capital / Utility Plant

Background

Each line of business develops a five-year Capital plan by individual project that includes the start date, the timing of expected spend projections and the in service date for each project. The Capital plan is entered into and maintained in PowerPlan.

The Senior Officers approve the Capital plan each year. The Capital plan is presented to the Senior Officers for approval by a subcommittee referred to as the Resource Allocation Committee ("RAC"). The RAC includes leaders from multiple business lines so that Capital decisions are made based on priorities of the company as a whole.

In order to import the capital budget into UI, Financial Planning receives an excel file from PowerPlan containing monthly capital construction expenditures (CWIP) and cost of removal (RWIP) by utility. There are categories in the model used to separate mechanism capital (ECR, DSM, GLT) from non-mechanism capital.

10. Closings to Plant in Service and Depreciation

After Capital Spending is booked to CWIP on the balance sheet, UI gets an import from PowerPlan by Plant account to determine additions to Plant in Service.

UI also imports a Depreciation forecast that is done based on capital plan, including property classifications and in service dates, and approved depreciation rates.

The approved depreciation rates are from the latest depreciation study, which are broken into life, salvage, and cost of removal per depreciation group. The rates are annual, so they are divided by 12 and multiplied by the monthly plant in service ending balances. The depreciation group to which an asset belongs is determined by the location and plant account selected at the time the capital project is setup in PowerPlan.

The plant in service ending balance for the most recent month of actuals is pulled out of PowerPlan. The ending balance of each forecast month is calculated as the beginning plant in service balance plus any capital additions placed in service for the month minus any asset retirements for the month. We use a half-month convention for additions and retirements. In the first month of an addition or retirement to plant in service, we divide the normal depreciation amount by two. This is done to average out the spend since the addition or retirement does not always occur on day one of the month.

The additions to plant in service are based on the capital forecast and the estimated in service dates on those assets. If the asset is already in service and additional money is spent on those assets, it is put in plant in service in that same month of spend. If the asset is not yet in service and spend occurs, it is held in CWIP until the month of the estimated in-service date in PowerPlan, on which date the entire CWIP balance is moved to plant in service.

11. Dividends, Debt and Equity

Dividends:

LG&E and KU pay dividends to its parent, LKE, on a quarterly basis. The dividend has historically been calculated in the model using a payout assumption equal to 65 percent of the previous quarter's net income. This percentage may be revised to maintain a balanced capital structure. Equity contributions from the parent may also be received by LG&E and KU to maintain the desired capital structure.

Capital Structure:

LG&E and KU (the "Utilities") strive to maintain a ratio of 53 percent equity and 47 percent debt. Within UI, the debt balancing and equity ratio targeting logic is different on the quarter versus non-quarter months. Equity ratio targeting reviews the capitalization ratios and rebalances it every quarter to 53 percent equity and 47 percent debt. The Utilities Parent (LKE) serves as the medium to move cash from the utilities to parent or from the parent to the utilities to maintain this ratio. Cash balancing logic looks at the cash needs and calculates how to fund those needs. It is important to note that UI limits cash balances at the utilities to $5 million unless short-term debt is zero and there is positive cash flow from operating and investing operations.

The following information is entered into UI for each individual debt issuance: company, issue date, interest rate, first interest payment date, issue amount, and retirement date. These debt issuance properties are entered and maintained in UI under the Edit Attributes module. The attributes in the business plan are compiled to create a case, which is used to run the Business Plan scenario.

On the non- quarter months, UI calculates cash needs from operating and investing operations and issues debt equal to cash shortage. Short-term debt in the form of commercial paper is issued first until it reaches a maximum as prescribed by the Treasury department (typically $300 million by utility) The utilities each have approved commercial paper programs of $350 million and FERC has approved short-term debt of up to $500 million for each utility. However, the utilities need to maintain liquidity for emergencies and to support certain floating rate tax-exempt bonds. Therefore, the Companies have a general modeling limit of $300 million on the commercial paper balances. The maximum can be changed after discussions with Treasury and the CFO. Once the maximum short-term debt is reached, long-term debt is issued in increments of $250 million or more and the balancing starts again the next month. The $250 million minimum is used because at that size the bonds are index-eligible and more attractive to investors, which results in a lower interest rate.

On the quarter months, the model balances equity and debt to a 53:47 ratio over multiple iterations. While performing the debt: equity targeting, UI issues only short-term debt to fund cash needs from operating and investing activities. The model is monitored to make sure that short-term debt balances are always within the acceptable limits. Similarly, to the non-quarter months, once the maximum short-term debt is reached, long-term debt is issued in increments of $250 million or more. Capital contributions in the form of equity from LKE are used to maintain the proper equity: debt ratios. LKE receives capital contributions from PPL to fund the utilities cash needs.

All short-term rates and interest on cash balances are based on a spread to the three-month LIBOR. The spread is based on current market issuances for similarly rated companies. For long-term debt, the rates are based on a spread to the US treasury rates (five-year, ten-year, thirty-year, etc.). The long-term debt spreads are also based on current levels for similarly rated entities and projected changes in those spreads for forecast periods. The forward curve as of a selected date is used to determine future LIBOR and US treasury rates.

12. Pension & Postretirement

Plan assumptions are evaluated by Senior Financial officers and Human Resources associates and the independent actuary. These assumptions are approved on an annual basis, barring any events requiring an interim re-measurement.

During the first half of the year, the independent actuary delivers a projection of estimated Plan funding, pension expense and pension liability for the five-year plan based on management's assumptions. These assumptions include the annual discount rate, the expected return on plan assets, the expected wage increase, the annual mortality rate table, funding policy and other assumptions as needed. The actuary's projections also incorporate the 15 year amortization of gains and losses as agreed in the 2014/2015 Kentucky rate case.

The projected pension and postretirement costs received from the actuary such as the service cost, interest cost, return on plan assets, and amortizations of prior service cost, transition, and (gain)/loss are summarized by company and by program offering. These amounts are used to update the annual budget by reflecting changes to the balance sheet for the revised liability projections and the pension cost used when calculating the employee burden rates by company. The pension burden rates are included in the O&M and Capital budgets entered into PowerPlan. These amounts are spread by month consistent with the timing of the labor budget.

Pension funding is assumed to occur annually in January while postretirement funding is assumed quarterly with the 401(h) portion of the funding occurring all in the second quarter.

13. Other Balance Sheet assumptions

a. Balances

The annual August balances from the balance sheet were the starting point for this forecast. The amounts were imported to UI from Oracle General Ledger (GL). A detailed and thorough balancing process is also done to ensure all details from Oracle translate appropriately into UI.

b. Cash

As noted above minimum cash balances are set each year at $5 million per utility. This is based on discussion with Treasury and if UI determines insufficient cash balances based on the projected activity short-term debt is issued.

c. Accounts Receivable and Unbilled Revenue

The monthly balances are based on forecasted revenues from customers and projected days of sales in receivables based on historical trends.

d. Fuels, materials and supplies (M&S)

Fuel inventory balances are developed based on targeted inventory levels for each generation plant. PROSYM is utilized to determine the amount of purchases needed to achieve the targeted inventory levels. Price assumptions for coal purchases utilize existing contract information as well as the assumed cost of coal that will be contracted in the future.

Natural Gas Inventory: Storage inventory levels are set within storage operating parameters in order to achieve maximum deliverability needed to meet winter season requirements. Price assumptions for gas purchases reflect forecasted gas prices and estimated pipeline transport costs.

Materials and supplies inventory is based on the annual August balance and is adjusted for disposals.

e. Prepayments affecting the balance sheet include insurance, IT contracts, PSC Fees, and TVA fees. For insurance, the amortization of the balance/expense begins at the start of the policy and continues through the term of the policy. For IT contracts, the estimated balances are amortized monthly over the period of services. For the PSC fees, and TVA fees, we receive a bill for the current year. The out years of the budget are escalated at an appropriate rate and the yearly cost is amortized over twelve months.

f. Unamortized debt expenses

For each bond issued, the Company incurs debt issuance costs, which are amortized over the period required by GAAP, generally the life of the debt issued. Additional financing costs that require amortization are unamortized loss on reacquired or remarketed debt, which is the expense that remains to be amortized when a debt instrument is remarketed/refinanced/repurchased. The financing costs are amortized over the life of the replacement debt. Amortized financing costs are calculated in excel for future periods and input into UI. The amortization expense flows to the income statement under interest expense. The unamortized financing costs are found on the balance sheet under other non-current assets and the unamortized loss on reacquired or remarketed debt are found on the balance sheet under regulatory assets.

g. Regulatory Assets and Liabilities

Adjustments to the regulatory assets and liabilities are obtained from schedules produced by the Company's Accounting Department, reflecting amortization rates previously approved by the Commission on existing line items and line of business proponent estimates for proposed line items. These schedules include storm costs, rate case expenses, MISO exit fees, interest rate swaps, deferred income taxes, etc.

Unrecognized pension and post-retirement costs are amortized as part of the monthly expense projections discussed earlier.

UI performs calculations for regulatory assets and liabilities associated with the various rate mechanisms to address regulatory lag issues and under/over recoveries. The amortization of interest rate swap regulatory liabilities and assets are performed using UI logic.

h. Asset retirement obligations (ARO)

The calculation of accretion expense is performed in an automated fashion within the PowerPlan Fixed Asset System. Accretion expense is calculated by taking the beginning ARO liability balance multiplied by the discount rate for each ARO.

Annual Electric Sales & Demand Forecast Process

PPL companies

Sales Analysis & Forecasting
September 2016

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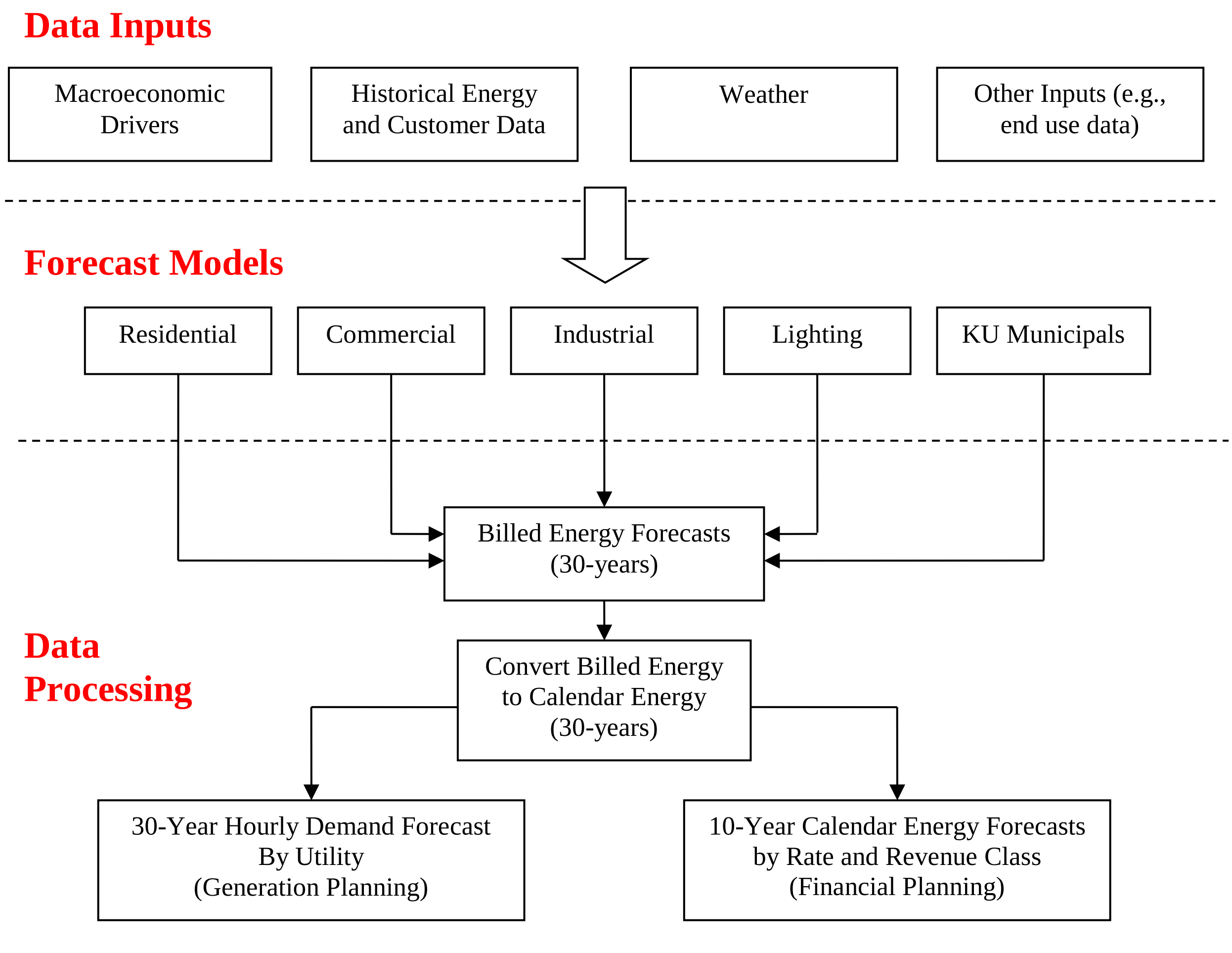
1. Introduction

The Sales Analysis & Forecasting group develops the annual Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies") sales and demand forecasts. These forecasts serve as foundational inputs for the Generation Planning department's annual Generation Forecast and the Financial Planning department's annual Business Plan. This document summarizes the processes used to produce the annual sales and demand forecasts. The forecast process can be divided into three parts (see Figure 1).

Figure 1 – Load Forecasting Process Diagram



The first part of the forecast process involves gathering and processing input data. The following are key inputs to the forecast process:

- Macroeconomic data
- Historical energy and customer data
- Weather data

- Other data, including billing cycle forecasts, class-level electricity price series, and residential appliance shares and efficiencies.

The input data is used to specify various forecast models. Generally, each model is used to forecast energy sales for a group of customers with homogeneous energy-use patterns within the same, or similar, tariff rates.

Most of the forecast models produce energy forecasts on a monthly billed basis.[1] In the third part of the forecast process, energy data from the forecast models is processed to meet the needs of forecast end users. The monthly billed energy forecasts must first be converted to calendar month (or "as-used") forecasts. The billed and calendar sales forecasts are allocated by rate and revenue class for the Financial Planning department.[2] In addition, a forecast of hourly energy requirements is developed for the Generation Planning department.[3]

The final part of the forecast process includes validating and documenting the forecast results. To ensure results are reasonable, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. Each of these steps is discussed in more detail in the following sections.

[1] All customers are assigned to one of 20 billing cycles. A billing cycle determines what time of the month a customer's meter is read. Because most billing cycles do not coincide precisely with the boundaries of calendar months, most customers' monthly bills will include energy that was consumed in multiple calendar months. The energy on customers' bills is referred to as "billed" energy.
[2] Rate class defines the tariff assigned to each customer meter while Revenue class is a higher level grouping; a Revenue class consists of one or more rate classes.
[3] Energy requirements are equal to sales plus transmission and distribution losses.

2. Input Data

Table 1 provides a summary of data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

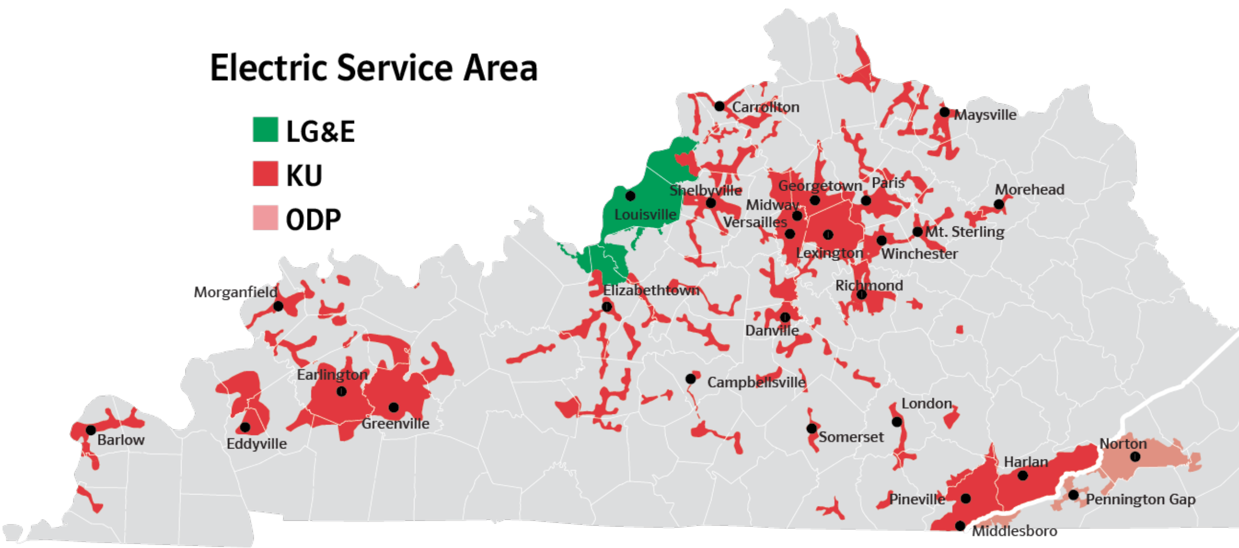
Table 1 – Summary of Forecast Data Inputs

Data	***Source***	***Format***
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	IHS Global Insight, Kentucky Data Center	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	IHS Global Insight	Annual or Quarterly – History and Forecast
Personal Income	IHS Global Insight	Annual by County
Weather	NOAA	Daily HDD/CDD Data by Weather Station – History
Bill Cycle Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	EIA, 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Elasticities of Demand	EIA / Historical Trend	Annual – History
Billed Sales History	CCS Billing System	LG&E, KU and ODP – Monthly by Rate Group
Number of Customers History	CCS Billing System	LG&E, KU and ODP – Monthly by Rate Group

2.1 Service Territory-Specific Macroeconomic Forecasts

IHS Global Insight produces forecasts of macroeconomic drivers by county. With an understanding of the counties that make up each service territory, this data can be used to create service territory-specific forecasts of macroeconomic drivers. Figure 2 contains a map of the LG&E and KU/ODP electric service territories.

Figure 2 – LG&E and KU/ODP Service Territory Map



Two counties make up the majority of the LG&E service territory, while KU serves customers in parts of over 70 counties; ODP's service territory includes parts of five counties in southwestern Virginia.[4] Service territory-specific macroeconomic forecasts are created by aggregating the applicable county-specific forecasts for the counties in LG&E, KU, and ODP service territories.

2.2 Software Tools

The following software packages are used in the forecast process:

- Microsoft Office: Excel, PowerPoint, Access
- SAS
- R
- Itron Metrix ND
- @Risk

2.3 Processing of Weather Data

Weather is a key explanatory variable in the electric forecast models. The weather dataset from the National Oceanic & Atmospheric Administration's (NOAA) National Climatic Data Center (NCDC) contains temperatures (maximum, minimum, and average), heating degree days (HDD), and cooling degree days (CDD) for each day and weather station over the past 20+ years. This data is used to create a historical weather series by billing month and a forecast of "normal" weather by billing month.[5] Each of these processes is summarized below.

[4] Appendix A contains a list of the counties in each service territory.
[5] "Normal" weather is defined as the average weather over a 20-year historical period. The Companies do not attempt to forecast any trends in weather.

2.3.1 Historical Weather by Billing Month

The methodology used to create the historical weather series by billing month consists of the following steps:

1. Using the historical daily weather data from the NCDC, sum the HDD and CDD values by billing cycle.[6] Each historical billing month consists of 20 cycles. The Companies' historical meter reading schedule contains the beginning and ending date for each billing cycle.
2. Average the billing cycle total HDDs and CDDs by billing month.

2.3.2 Normal Weather Forecast by Billing Month

The methodology used to produce the forecast of normal weather by billing month includes the production of a daily forecast of normal weather. The methodology used to develop the daily forecast (summarized in Steps 2-5) is consistent with the methodology used by the NCDC to create its daily normal weather forecast.[7] The following steps are used to create the forecast of normal weather by billing month:

1. Compute the forecast of normal monthly weather by *calendar* month by averaging monthly degree-day values over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 20-year historical period. Therefore, the normal HDD value for January is the average of the 20 January HDD values in this period.
2. Compute "unsmoothed" daily normal weather values by averaging temperature, HDDs, and CDDs by calendar day. The unsmoothed normal temperature for January 1, for example, is computed as the average of the 20 January 1 temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered about the desired day. The "smoothed" normal temperature for January 1, for example, is computed as the average of the unsmoothed daily normal temperatures between December 16 and January 15.
4. Manually adjust the integer values in Step 3 so that the following criteria are met:
    a. The monthly average temperature – computed by averaging the daily temperatures by month and rounding to the nearest integer – should match the normal monthly temperatures in Step 1.
    b. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
    c. The daily temperatures and CDDs should be monotonically increasing from winter to summer and monotonically decreasing from summer to winter. The daily HDD series should follow a reverse trend.

   These criteria ensure the daily normal series is consistent with the monthly normal series.
5. The Companies' forecasted meter reading schedule contains the beginning and ending date for each billing cycle through the end of the forecast period. In this step, sum the HDD and CDD values by billing cycle. Use the February 28 weather data as a proxy for February 29 when billing cycles include leap days.
6. Average the billing cycle totals by billing month.

[6] Weather data in the electric forecast is taken from the weather stations at the Bowman Field Airport (LOU) in Louisville, Bluegrass Field Airport (LEX) in Lexington, and Tri-Cities Airport in Tennessee.
[7] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

3. Forecast Models

The Companies' energy forecast is comprised of multiple forecast models. All models forecast sales and the number of customers on a monthly basis. These forecasts are discussed in detail in the following sections.

3.1 Residential Forecast

The Residential forecast is comprised of three classes: KU Residential, LG&E Residential, and ODP Residential. The Residential forecast includes all customers on the Residential Service (RS) and Volunteer Fire Department (VFD) rate schedules. Residential sales are forecasted for each company as the product of a customer forecast and a use-per-customer forecast.

3.1.1 Residential Customer Forecast

The number of residential customers is forecasted by company as a function of the number of forecasted households or forecasted population in the service territory. Household and population data by county and Metropolitan Statistical Area (MSA) is available from IHS Global Insight and the Kentucky Data Center.

3.1.2 Residential Use-per-Customer Forecast

Average use-per-customer is forecast using a Statistically-Adjusted End-Use (SAE) Model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

$$\text{Use-per-Customer} = a1*XHeat + a2*XCool + a3*XOther$$

The heating, cooling and other components (i.e., the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and electricity prices. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A complete summary of this model is contained in Appendix A to Itron's Residential SAE Update; this appendix is attached as Appendix B.

3.2 Commercial Forecast

The Commercial forecast is comprised of the following models: KU General Service, KU Commercial, KU All-Electric Schools, LG&E General Service, LG&E Commercial, ODP General Service, ODP Commercial, ODP Schools and ODP Municipal Pumping. Each of these rate classes is forecasted separately on a monthly basis over the forecast period. The period of historical data used in the models varies based on each rate class's history.

3.2.1 KU, LG&E, and ODP General Service

The general service forecasts include all customers on the General Service (GS) rate and are comprised of two separate forecasts: a sales forecast and a customer forecast. The former employs a Statistically-Adjusted End-Use model (SAE), which defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment. A complete summary of this model is contained in Appendix A to Itron's Commercial SAE Update; this appendix is attached as Appendix C.

The customer forecasts are a function of household or population growth since, historically, they are highly correlated.

3.2.2 KU Commercial

The KU Commercial forecast includes all customers on the PS Secondary and TOD Secondary rates. Sales to PS Secondary customers are modeled as a function of heating and cooling degree days, Retail and Wholesale Employment indices, and binary variables which account for anomalies in the historical data.

3.2.3 KU All-Electric Schools (AES)

The KU All-Electric Schools forecast includes all customers on the All-Electric School rate schedule. KU AES sales are modeled as a function of the number of KU households, weather, and binary variables to account for anomalies in the historical data.

3.2.4 LG&E Commercial

The LG&E Commercial forecast includes all customers on the CPS Primary, CPS Secondary, CTOD-Primary, and CTOD-Secondary rate schedules. The Primary and Secondary rates are forecasted separately to capture similar energy usage patterns and levels. LG&E Commercial sales are forecast in total as a function of weather, specific economic drivers, the number of customers, and other binary variables to account for anomalies in the historical data.

3.2.5 LG&E Special Contracts

The LG&E Special Contracts forecast includes Louisville Water Company and Fort Knox. These customers are forecasted individually, based on information and feedback from the customers and major account representatives.

3.2.6 ODP Commercial

The ODP Commercial forecast includes all customers on the PS Secondary and TOD Secondary rates. Sales to PS Secondary customers are modeled as a function of heating and cooling degree days, specific economic drivers, and binary variables which account for anomalies in the historical data.

3.2.7 ODP Schools

The ODP Schools forecast includes all customers on the School Service (SS) rate schedule. Sales to the ODP schools are modeled as a function of the number of households, weather, and binary variables.

3.2.8 ODP Municipal Pumping

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. ODP municipal pumping sales are forecasted using a trend model based on recent sales.

3.3 Lighting Forecast

The Lighting forecast is comprised of the following rate classes: LG&E LES and TES, KU LES and TES, and unmetered Street Lighting for each company. All lighting-related energy is forecasted using a trend model based on recent sales.

3.4 Industrial Forecast

A relatively small number of customers in an industrial rate can make up a significant portion of the total sales for that rate. Furthermore, any expansion or reduction in operations by the larger industrial customers can significantly impact the Companies' load forecast. Therefore, the Companies work directly with the largest industrial customers (Major Accounts) to develop their forecasts. The large individually forecasted customers are removed from the historical energy sales data by rate, while the remaining customers are forecasted using econometric models described below. The total rate forecast is the combination of the individually forecasted customers and the customers forecasted using econometric models.

3.4.1 KU Industrial Forecast

The KU industrial forecast is comprised of three forecast models. The forecast models are aggregated by rate codes by voltage level.

3.4.1.1 Primary

The PS Primary, TOD Primary, and LTOD Primary rates are forecasted together, then allocated into individual rate forecasts using historical sales ratios. The Primary forecast includes all customers that take service at the primary distribution voltage. Sales to Primary customers are modeled as a function of an industry-weighted Industrial Production Index and weather.

3.4.1.2 Retail Transmission Service

The RTS forecast includes all retail customers previously on a Transmission-level rate. Since a large component is sales to Mine Power customers, the Wood-MacKenzie forecast of Eastern and Western Kentucky coal production is used as a driver. In recent years, the demand for lower sulfur eastern Kentucky coal has declined while the demand for higher sulfur western Kentucky coal has increased. Therefore, two mining forecasts are developed to more accurately reflect this trend. The two forecasts are combined to form the final KU RTS forecast.

3.4.1.3 Fluctuating Load Service

The FLS forecast includes one customer, the North American Stainless Arc Furnace. The FLS forecast is developed based on discussions with the customer.

3.4.2 LG&E Industrial Forecast

The LG&E industrial forecast consists of three forecast models: Industrial Primary (Power Service and Time of Day), Industrial Secondary (Power Service and Time of Day), and Retail Transmission Service. Each of these rate classes is forecasted separately with specific economic drivers and weather.

3.4.2.1 Industrial Primary (Power Service and Time of Day)

The Industrial Primary forecast includes all customers on Industrial Primary rates. Monthly sales are modeled as a function of an industry-weighted Industrial Production Index, number of customers, and weather.

3.4.2.2 Industrial Secondary (Power Service and Time of Day)

The Industrial Secondary forecast includes all customers on Industrial secondary rates. Monthly sales are modeled as a function of an industry-weighted Industrial Production Index, number of customers, and weather.

3.4.2.3 Retail Transmission Service

The RTS rate consists of both individually forecasted major accounts and smaller customers. The major accounts customer forecasts are developed with input from the major account managers and customer input. The remaining smaller customer forecasts are developed using a trend model based on recent sales.

3.4.3 ODP Industrial Forecast

The ODP industrial forecast is a combined forecast of PS Primary, TOD Primary, and RTS rates. Industrial sales are forecasted as a function of the Eastern Kentucky Wood-MacKenzie index, number of customers, and weather.

3.5 KU Municipal Forecast

KU municipal forecasts are provided by various consultants for different cities. These forecasts are reviewed for consistency and compared to historical sales and trends. Questions or concerns regarding the forecasts are sent to the municipal customers and their consultants, if applicable. Any subsequent revisions received from the municipal customers are incorporated into the forecasts.

3.6 Billed Demand Forecast

The Billed Demand forecasts are based on historical demand factors, where the demand factor is the billed demand volume divided by the billed sales volume. The historical demand factor is then multiplied by the sales forecast for rates that have billed demand components.

4. Data Processing

The Companies' customers are assigned to one of 20 billing cycles. Because most billing cycles do not coincide directly with the boundaries of calendar months, most customers' monthly bills will include energy that was consumed in multiple calendar months. The energy on customers' bills is referred to as "billed" energy. Most historical sales data is recorded on a billed basis. As a result, most energy forecasts are produced initially on a billed basis. To meet the needs of the forecast end users, the billed energy must be further processed. The following processes are discussed in more detail in the following sections:

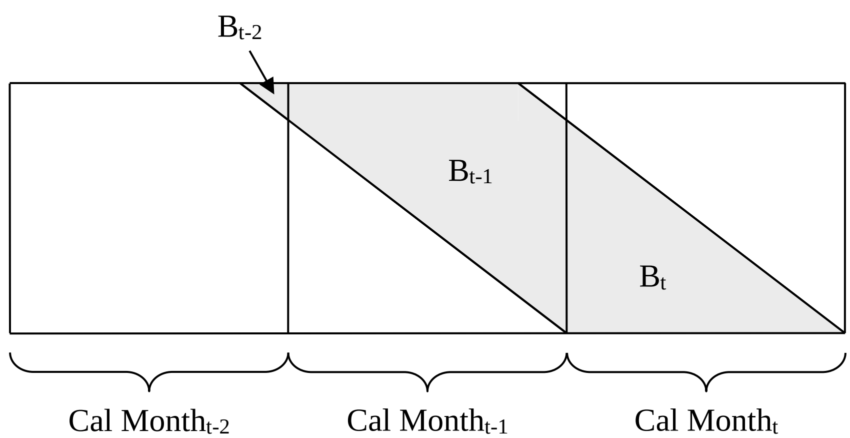
1. Billed-to-Calendar Energy Conversion
2. Rate Code and Revenue Class Allocation
3. Hourly Energy Requirements Forecast

4.1 Billed-to-Calendar Energy Conversion

Since the billed volumes for most forecast classes do not coincide directly with the boundaries of calendar months, most class forecast volumes must be converted from a billed to calendar basis. Forecasts for the following rate classes do not have to be converted from a billed to calendar basis: LG&E Special Contracts, KU FLS and KU municipals. The customers in these forecast classes are billed on a calendar-month basis.

The shaded area in Figure 3 represents a typical billing month (B). Area B_t represents the volumes in the billing month that were consumed in the current calendar month (time = t). Area B_{t-1} represents the volumes in the billing month that were consumed in the previous calendar month (time = t-1). Area B_{t-2} represent the volumes in the billing month that were consumed in the calendar month two months prior to the current month (time = t-2).[8]

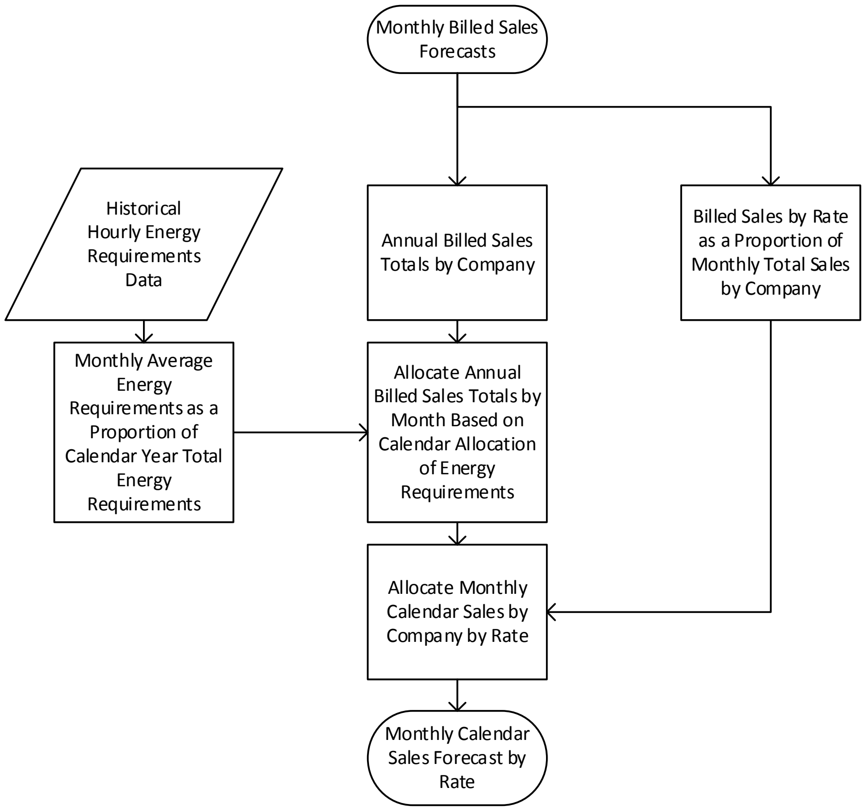
Figure 3 – Billed and Calendar Energy



Using historical hourly energy requirements data by company (KU/ODP, LG&E) to obtain calendar monthly allocation ratios, the annual billed sales forecasts (by company) are allocated into months using the calendar monthly allocation ratios. This yields monthly calendar sales forecasts by company. These monthly calendar sales by company are then allocated into rate classes using the ratio of billed sales by rate to total billed sales. Figure 4 shows a diagram of the process.

[8] Not all billing months include volumes that were consumed in the calendar month two months prior to the current month.

Figure 4 – Billed-to-Calendar Allocation



4.2 Rate-to-Revenue Class Allocation

To meet revenue forecasting requirements, the billed and calendar energy forecasts, which are initially developed by rate class, must be allocated to revenue classes. Revenue class is a higher level grouping; all rate classes are allocated to one or more of the following revenue classes (see Appendix D):

- Residential
- Commercial
- Industrial
- Public Authority
- Wholesale
- Lighting

This information is used by the Financial Planning department to develop a forecast of revenues for the planning period. Billed and calendar forecasts are allocated by rate and revenue class using a set of monthly allocation ratios. These ratios are derived based on historical sales data from CCS for energy, demand, and customers by rate class and revenue class.

4.3 Hourly Energy Requirements Forecast

The hourly energy requirements forecast is developed from the final sales forecasts. The Generation Planning department uses the hourly energy requirements forecast to develop resource expansion plans and a forecast of generation production costs. The following steps are used to create the hourly energy requirements forecast:

1. For each company and month, add an estimate for system losses to the sum of calendar sales to compute monthly calendar energy requirements.
2. For each company and for every month except the peak month (August), compute an average normalized load duration curve based on ten years of historical hourly energy requirements. For the peak month, the process is similar except the year with the lowest load factor and the years with the five highest load factors are excluded from the average. By focusing the average on some of the lower load factors, the resulting peak demand for each company (computed in step 3) will reflect a "summer" peak demand and not an average peak demand for the month of August. Because the summer peak could occur in any summer month, the average summer peak demand is higher than the average peak demand in August.
3. For each company and month, multiply each value in the normalized load duration curve by monthly energy requirements to produce hourly demands.
4. For each company and month, order the hourly demands chronologically based on load patterns in "reference months." The reference months (a) capture the calendar attributes of the forecast month in question (i.e., the pattern of weekdays and weekends over the month) and (b) maintain the historic relationship of (approximate) peak coincidence between the two companies.
5. For each month and hour, add the chronological load curves to produce an hourly energy requirements forecast for the combined companies.

Appendix A – Service Territories and Their Component Counties

Kentucky Utilities		LG&E Electric	LG&E Gas	Old Dominion Power
Adair	Hopkins	Bullitt	Barren	Dickenson,VA
Anderson	Jessamine	Hardin	Bullitt	Lee, VA
Ballard	Knox	Jefferson	Green	Russell, VA
Barren	Larue	Meade	Hardin	Scott, VA
Bath	Laurel	Oldham	Henry	Wise, VA
Bell	Lee	Trimble	Hart	
Bourbon	Lincoln		Jefferson	
Boyle	Livingston		Larue	
Bracken	Lyon		Marion	
Bullitt	McCracken		Meade	
Caldwell	McCreary		Metcalfe	
Campbell	McLean		Nelson	
Carlisle	Madison		Oldham	
Carroll	Marion		Shelby	
Casey	Mason		Spencer	
Christian	Mercer		Trimble	
Clark	Montgomery		Washington	
Clay	Muhlenberg			
Crittenden	Nelson			
Daviess	Nicholas			
Edmonson	Oldham			
Estill	Owen			
Fayette	Pendleton			
Fleming	Pulaski			
Franklin	Robertson			
Fulton	Rockcastle			
Gallatin	Rowan			
Garrard	Russell			
Grant	Scott			
Grayson	Shelby			
Green	Spencer			
Harlan	Taylor			
Hardin	Trimble			
Harrison	Union			
Hart	Washington			
Henderson	Webster			
Henry	Whitley			
Hickman	Woodford			

Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. Econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to identify and isolate the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly incorporating trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_{m} = a + b_1 \times \mathrm{XHeat}_{m} + b_2 \times \mathrm{XCool}_{m} + b_3 \times \mathrm{XOther}_{m} + \varepsilon_{m} \tag{2}$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2009 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times HeatShare_{09}^{Type} \qquad (7)$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2009 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models and thereafter, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a 10-year horizon. To introduce price effects, the Heat Index as defined by

Equation 4 above is multiplied by a 10-year moving-average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \tag{8}$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09,7}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09,7}}\right)^{\kappa} \tag{9}$$

Where:

- *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2009
- *HHSize* is average household size in a year (y)
- *Income* is average real income per household in year (y)
- *ElecPrice* is the average real price of electricity in month (m) and year (y)
- *GasPrice* is the average real price of natural gas in month (m) and year (y)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \Big/ Eff_{09}^{Type} \right)} \qquad (11)$$

Data values in 2009 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times CoolShare_{09}^{Type} \qquad (12)$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2009 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models and thereafter, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \Big/ Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \tag{13}$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09}}\right)^{\kappa} \tag{14}$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2009.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{15}$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{09}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{16}$$
$$(TenYearMovingAverageElectric\Pr ice)^{\lambda} \times (TenYearMovingAverageGas\Pr ice)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.10} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09}}\right)^{\phi} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09}}\right)^{\lambda} \quad (17)$$

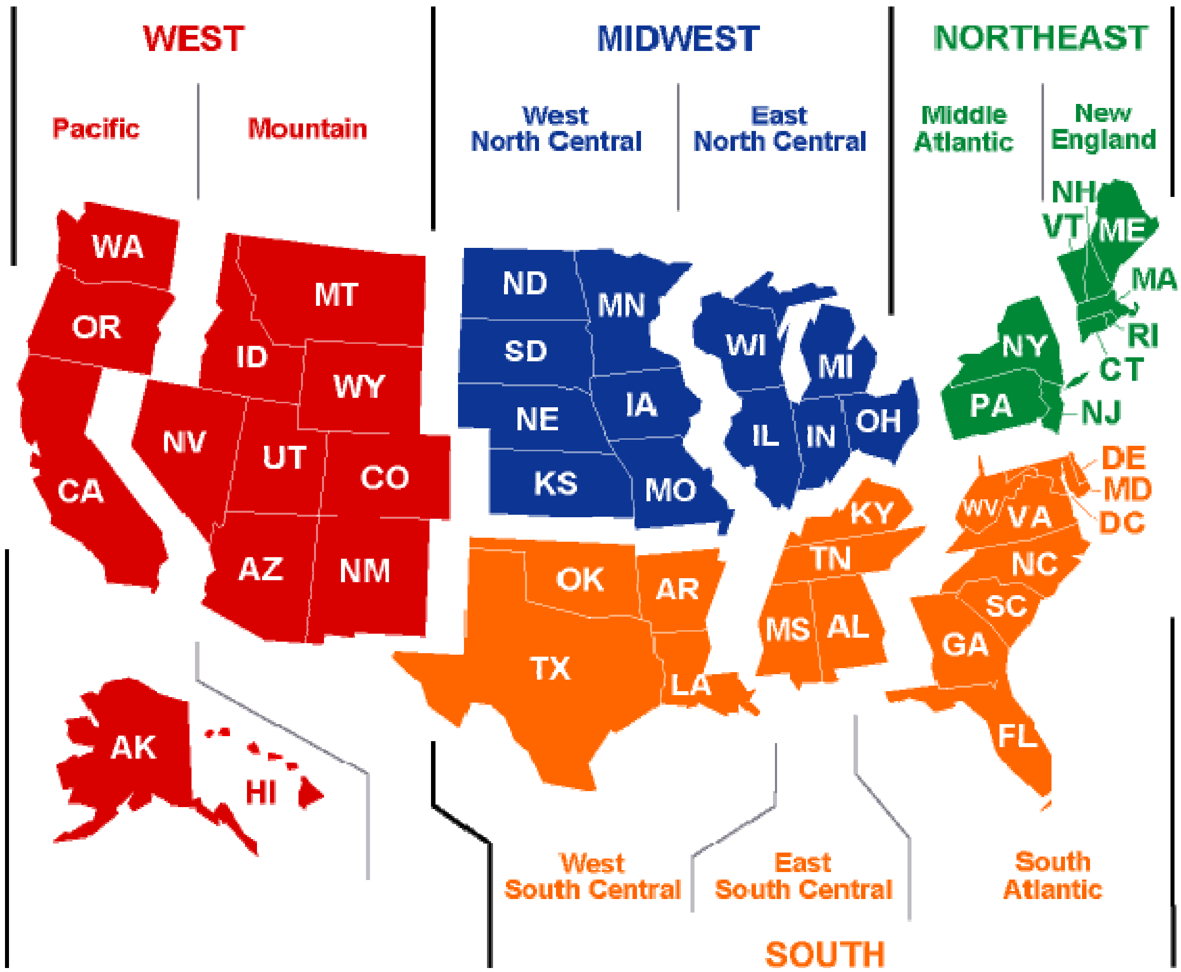
The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (18)$$

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in Figure 18. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 3.

Figure 18: Mapping of States to Census Divisions



Source: http://www.eia.doe.gov/emeu/reps/maps/us_census.html

Table 3: List of SAE Files

Spreadsheet	*MetrixND* Project File
NewEngland.xls	SAE_NewEngland.ndm
MiddleAtlantic.xls	SAE_MiddleAtlantic.ndm
EastNorthCentral.xls	SAE_EastNorthCentral.ndm
WestNorthCentral.xls	SAE_WestNorthCentral.ndm
SouthAtlantic.xls	SAE_SouthAltantic.ndm
EastSouthCentral.xls	SAE_EastSouthCentral.ndm
WestSouthCentral.xls	SAE_WestSouthCentral.ndm
Mountain.xls	SAE_Mountain.ndm
Pacific.xls	SAE_Pacific.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The *MetrixND* project files are linked to the data in these spreadsheets. In these project files, the end-use *Usage* variables are constructed and the SAE model is estimated.

Each of the nine SAE spreadsheets contains the following tabs.

- **Definitions -** Contains equipment, end use, worksheet, and Census Division definitions.
- **Intensities -** Calculates the annual equipment indices.
- **Shares -** Contains historical and forecasted equipment shares. The default forecasted values are provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **Efficiencies -** Contains historical and forecasted equipment efficiency trends. The forecasted values are based on projections provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **StructuralVars -** Contains historical and forecasted square footage, number of households, building shell efficiency index, and calculation of structural variable. The forecasted values are based on projections provided by the EIA.
- **Calibration -** This tab contains calculations of the base year *Intensity* values used to weight the equipment indices.
- **EIAData -** Contains the raw forecasted data provided by the EIA.
- **MonthlyMults -** Contains monthly multipliers that are used to spread the annual equipment indices across the months.
- **EV -** Worksheet for incorporating electric vehicle (EV) impacts.
- **PV -** Worksheet for incorporating photovoltaic battery (PV) impacts.

The *MetrixND* Project files are linked to the *AnnualIndices*, *ShareUEC*, and *MonthlyMults* tabs in the spreadsheets. Sales, economic, price and weather information for the Census Division is provided in the linkless data table *UtilityData*. In this way, utility specific data and the equipment indices are brought into the project file. The *MetrixND* project files contain the objects described below.

Parameter Tables

- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use. There are five types of elasticities included on this table.

  - Economic variable elasticities
  - Short-term own price elasticities
  - Short-term cross price elasticities
  - Long-term own price elasticities

- Long-term cross price elasticities

The short-term price elasticities drive the end-use usage equations. The long-term price elasticities drive the Heat, Cool and other appliance indices. The combined price impact is an aggregation of the short and long-term price elasticities. As such, the long-term price elasticities are input as incremental price impact. That is, the long-term price elasticity is the difference between the overall price impact and the short-term price elasticity.

Data Tables

- **AnnualEquipmentIndices.** This data table is linked to the *AnnualIndices* tab for heating and cooling indices, and *ShareUEC* tab for water heating, lighting, and appliances in the SAE spreadsheet.
- **UtilityData.** This is a linkless data table that contains sales, price, economic and weather data specific to a given Census Division.
- **MonthlyMults.** This data table is linked to the corresponding tab in the SAE spreadsheet.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **ResidentialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.
- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table is used to compute the monthly sales forecasts by end uses.

Models

- **ResModel:** This is the Statistically Adjusted End-Use Model.

Steps to Customize the Files for Your Service Territory

The files that are included in this package contain regional data. If you have more accurate data for your service territory, you are encouraged to tailor the spreadsheets with that information. This section describes the steps needed to customize the files.

Minimum Customization

- Save the *MetrixND* project file and the spreadsheet into the same folder
- Select the spreadsheet and *MetrixND* project file from the appropriate Census Division
- Open the spreadsheet and navigate to the *Calibration* tab
- In cell "B8", replace base year Census Division use-per-customer with observed use-per-customer for your service territory
- Save the spreadsheet and open the *MetrixND* project file
- Click on the *Update All Links* button on the *Menu* bar
- Review the model results

Customizing the End-use Share Paths

In addition to the minimum steps listed above, you can install your own share history and forecasts. To do this, navigate to the *Share* tab in the spreadsheet and paste in the values for your region. Make sure that base year shares on the *Calibration* tab reflect changes on the *Shares* tab.

Customizing the End-use Efficiency Paths

Finally, you can override the end-use efficiency paths that are contained on the *Efficiencies* tab of the spreadsheet.

Appendix A:
Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to identify the end-use factors driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to the SAE approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast, thereby providing a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and efficiency levels, SAE models can explain changes in usage levels and weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.3 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \text{Other}_{y,m} \quad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

Where

- $XHeat_{y,m}$ is estimated heating energy use in year y and month m,
- $HeatIndex_y$ is the annual index of heating equipment, and
- $HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y \big/ Eff_y \right)}{\left(HeatShare_{04} \big/ Eff_{04} \right)} \tag{4}$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft} \right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh \big/ Sqft_e} \right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}} \right)^{-0.18} \tag{6}$$

Where

- *BDays* is the number of billing days in year *y* and month *m*, these values are normalized by 30.5, which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month
- *HDD* is the annual heating degree days for 2004,
- *Output* is a real commercial output driver in year *y*,

- *Price* is the average real price of electricity in month *m* and year *y*,

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{7}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year *y* and month *m*,
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left(CoolShare_y \big/ Eff_y \right)}{\left(CoolShare_{04} \big/ Eff_{04} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh/Sqft_{e}}\right) \qquad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \qquad (10)$$

Where

- *WgtCDD* is the weighted number of cooling degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_{y}^{Type} \big/ Eff_{y}^{Type}}{Share_{04}^{Type} \big/ Eff_{04}^{Type}} \right) \tag{12}$$

Where

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh \big/ Sqft_{e}} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

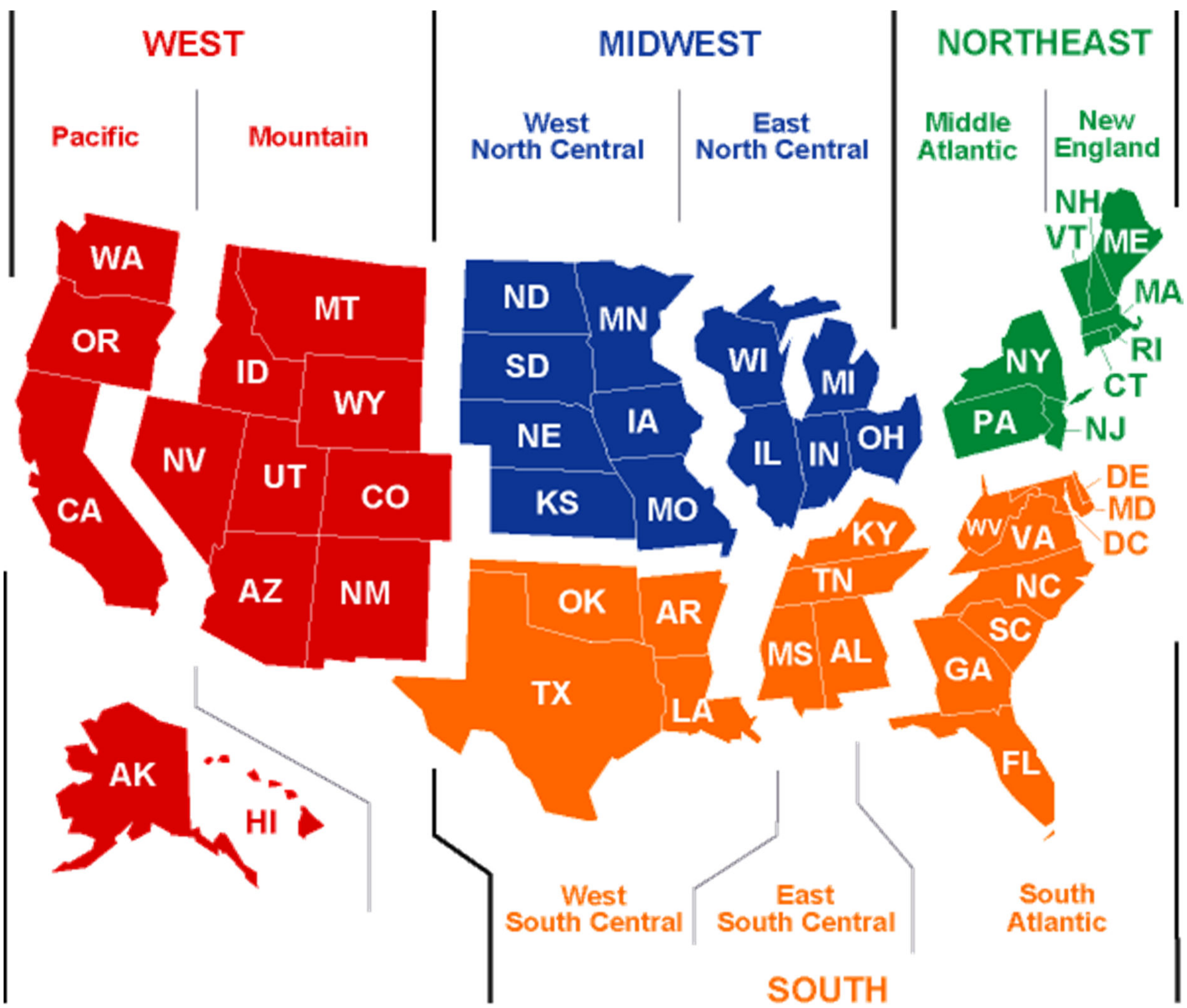
$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}}\right)^{-0.18} \quad (14)$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

1.4 Supporting Spreadsheets and *MetrixND* Project Files

The SAE approach described above has been implemented for each of the nine census divisions. A mapping of states to census divisions is presented in Figure 1. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 1.

Figure 1: Mapping of States to Census Divisions*



*Map Source: http://www.eia.gov/consumption/manufacturing/maps.cfm

Table 1: List of SAE Files

Spreadsheets	*MetrixND* Project Files
NewEnglandCom.xls	NewEnglandCom.ndm
MiddleAtlanticCom.xls	MiddleAtlanticCom.ndm
EastNorthCentralCom.xls	EastNorthCentralCom.ndm
WestNorthCentralCom.xls	WestNorthCentralCom.ndm
SouthAtlanticCom.xls	SouthAltanticCom.ndm
EastSouthCentralCom.xls	EastSouthCentralCom.ndm
WestSouthCentralCom.xls	WestSouthCentralCom.ndm
MountainCom.xls	MountainCom.ndm
PacificCom.xls	PacificCom.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The data from these spreadsheets are linked to the *MetrixND* project files. In these project files, the end-use *Usage* variables (Equations 6, 10, and 14 above) are constructed and the SAE model is estimated.

The nine spreadsheets contain the following tabs.

- **BaseYrInput.** This tab contains base year Census Division intensities by end-use and building type as well as default building type weights. It also contains functionality for changing the weights to reflect utility service territory.
- **Efficiency.** This tab contains historical and forecasted end-use equipment efficiency trends. The forecasted values are based on projections provided by the EIA.
- **Shares.** This tab contains historical and forecasted end-use saturations. The procedure by which these are calculated is explained in the text above.
- **ShareEff.** This tab is used for the calculation of the annual equipment indices.
- **AnnualIndices.** This tab contains the annual *Heat*, *Cool* and *Other* equipment indices.
- **Intensity.** This tab contains the annual intensity (kWh/sqft) projections by end-use.
- **FloorSpace.** This tab contains the annual floor space (sqft) projections by end-use.
- **PV.** This tab is used to incorporate the impact of photovoltaic batteries into the forecast.

The *MetrixND* project files contain the following objects.

Parameter Tables

- **Parameters.** This parameter table includes the values of the annual HDD and CDD in 2004 used to calculate the *Usage* variables for each end-use.
- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use.

Data Tables

- **AnnualIndices.** This data table is linked to the *AnnualIndices* tab in the Commercial SAE spreadsheet and contains sales-adjusted commercial SAE indices.
- **Intensity.** This data table is linked to the *Intensity* tab in the Commercial SAE spreadsheet.
- **FloorSpace.** This data table links to *FloorSpace* tab in the Commercial SAE spreadsheet.
- **UtilityData.** This linkless data table contains Census Division level data. It can be populated with utility-specific data.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the output and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **CommercialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model. Structural variables based on the intensity/floor space combination are also calculated here.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.
- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table breaks the forecast down into its heating, cooling and other components.

Models

- **ComSAE:** The commercial SAE model (energy forecast driven by end-use indices, price, and output projections).
- **ComStruct:** Simple stock model (energy forecast driven by end-use energy intensities, and square footage).

Appendix D - Rate Class to Revenue Class Allocation

Company	*Revenue Class*	*Rate Class*
KU	Commercial	AES
		GS
		LES
		LTOD-Pri
		PS-Pri
		PS-Sec
		RS
		RTS
		TES
		TOD-Pri
		TOD-Sec
		Unmetered
	Industrial	AES
		FLS
		GS
		LTOD-Pri
		PS-Pri
		PS-Sec
		RS
		RTS
		TOD-Pri
		TOD-Sec
		Unmetered
	Lighting	GS
		LES
		RS
		TES
		Unmetered
	Public	AES
		GS
		LTOD-Pri
		PS-Pri
		PS-Sec
		RS
		RTS
		TES
		TOD-Pri
		TOD-Sec
		Unmetered
	Residential	GS
		RS
		TES
		Unmetered

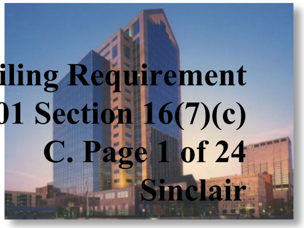
Company	***Revenue Class***	***Rate Class***
	Wholesale	Muni-Paris Muni-Primary Muni-Transmission
LG&E	Commercial	CPS-Pri CPS-Sec CTOD-Pri CTOD-Sec GS IPS-Sec ITOD-Pri ITOD-Sec LES RS Unmetered
	Industrial	CPS-Sec CTOD-Sec GS IPS-Pri IPS-Sec ITOD-Pri ITOD-Sec RS RTS Unmetered
	Lighting	GS LES TES Unmetered
	Public	CPS-Pri CPS-Sec CTOD-Pri CTOD-Sec Fort Knox GS IPS-Pri IPS-Sec ITOD-Pri ITOD-Sec LES Louisville Water RS RTS TES Unmetered
	Residential	GS RS Unmetered

Company	***Revenue Class***	***Rate Class***
ODP	Commercial	AES
		FWP
		GS
		PS-Pri
		PS-Sec
		RS
		TOD-Sec
		Unmetered
	Industrial	GS
		PS-Pri
		PS-Sec
		RTS
		TOD-Pri
		TOD-Sec
		Unmetered
	Lighting	GS
		Unmetered
	Public	AES
		GS
		PS-Pri
		PS-Sec
		RS
		TOD-Pri
		TOD-Sec
		Unmetered
	Residential	GS
		RS
		Unmetered

PPL companies

2017 Business Plan Electric Sales Forecast

July 11, 2016



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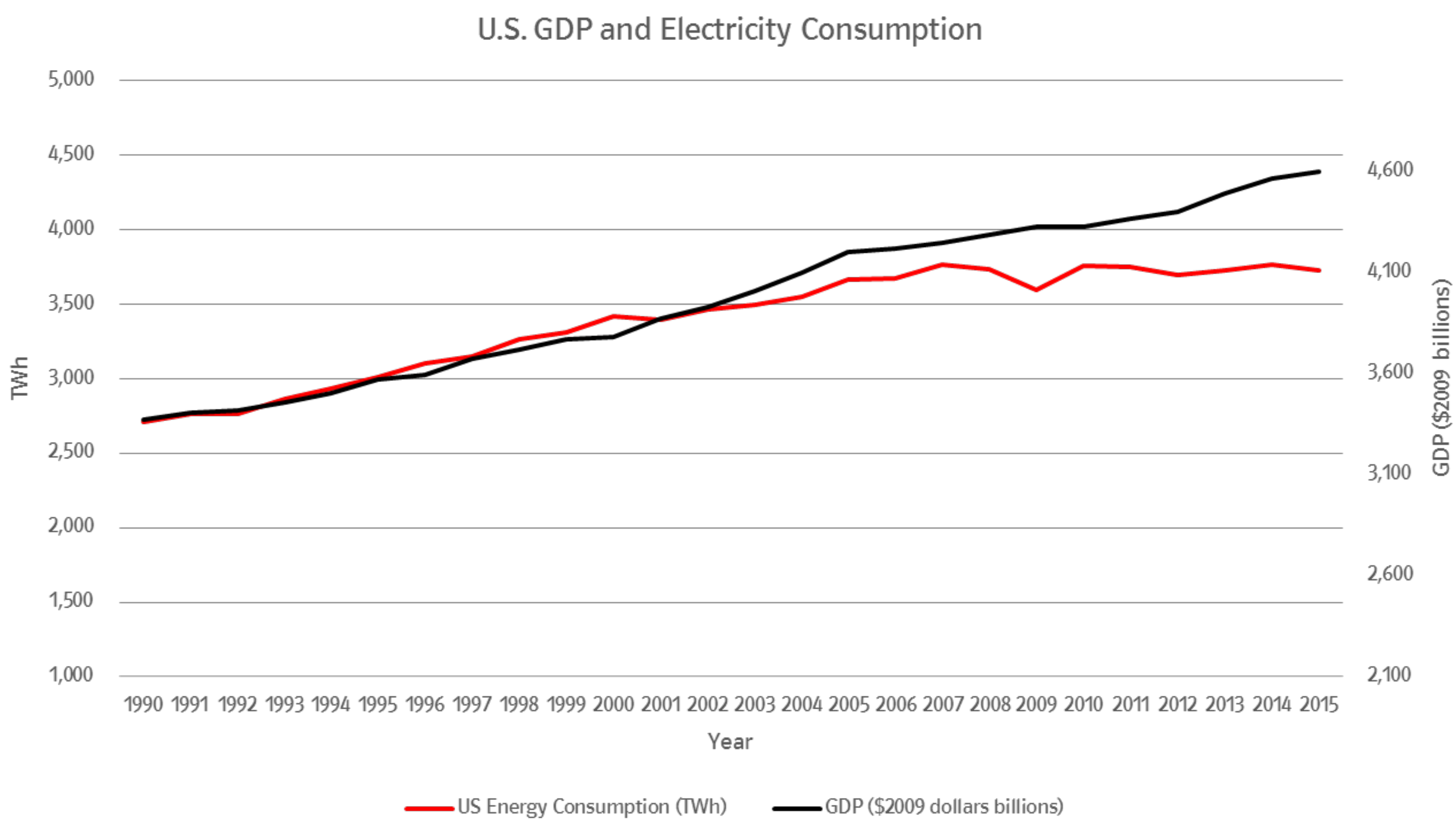
C. Page 1 of 24
Sinclair

US electricity demand has remained flat from 2010-2015



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PPL companies

Structural headwinds may lead to declining US electricity growth

- Morgan Stanley forecasts US electricity consumption to decrease by ~0.3% annually over the next decade
  - *Forecast risk skewed to the downside given the potential for efficiency breakthroughs and / or incremental government regulations*
  - *GDP, population, computing, and electric vehicles provide the most upside*
- 0.3% CAGR 2015-2040 residential sales (EIA)
  - *Reduced from 0.5% in previous AEO*
- 0.54% CAGR in electricity sales through 2035 (PIRA)
  - *Reduced from 0.83% in previous forecast*

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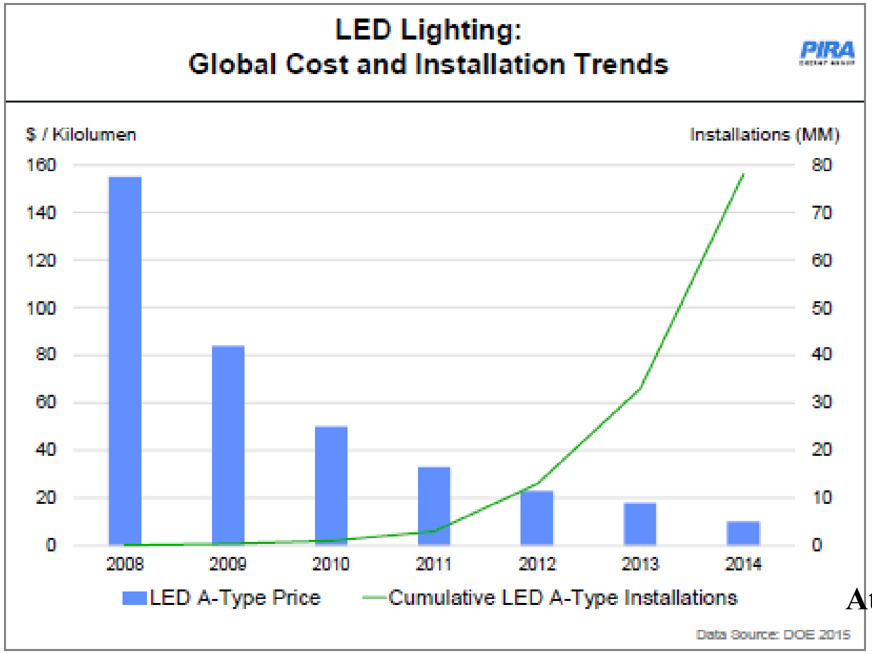
Greater anticipated end-use efficiencies drive reductions in PIRA electricity sales forecast

- LED Lighting
  - *Costs have fallen 90% since 2008; efficiency expected to double by 2025.*
  - *DOE forecasts 48% market share by 2020 and 84% in 2030, up from 2% in 2013. This would reduce lighting consumption by 15% in 2020 and 40% in 2030.*
- Space Cooling
  - *New standard for commercial rooftop air conditioners in 2018 expected to cut consumption by 30%.*



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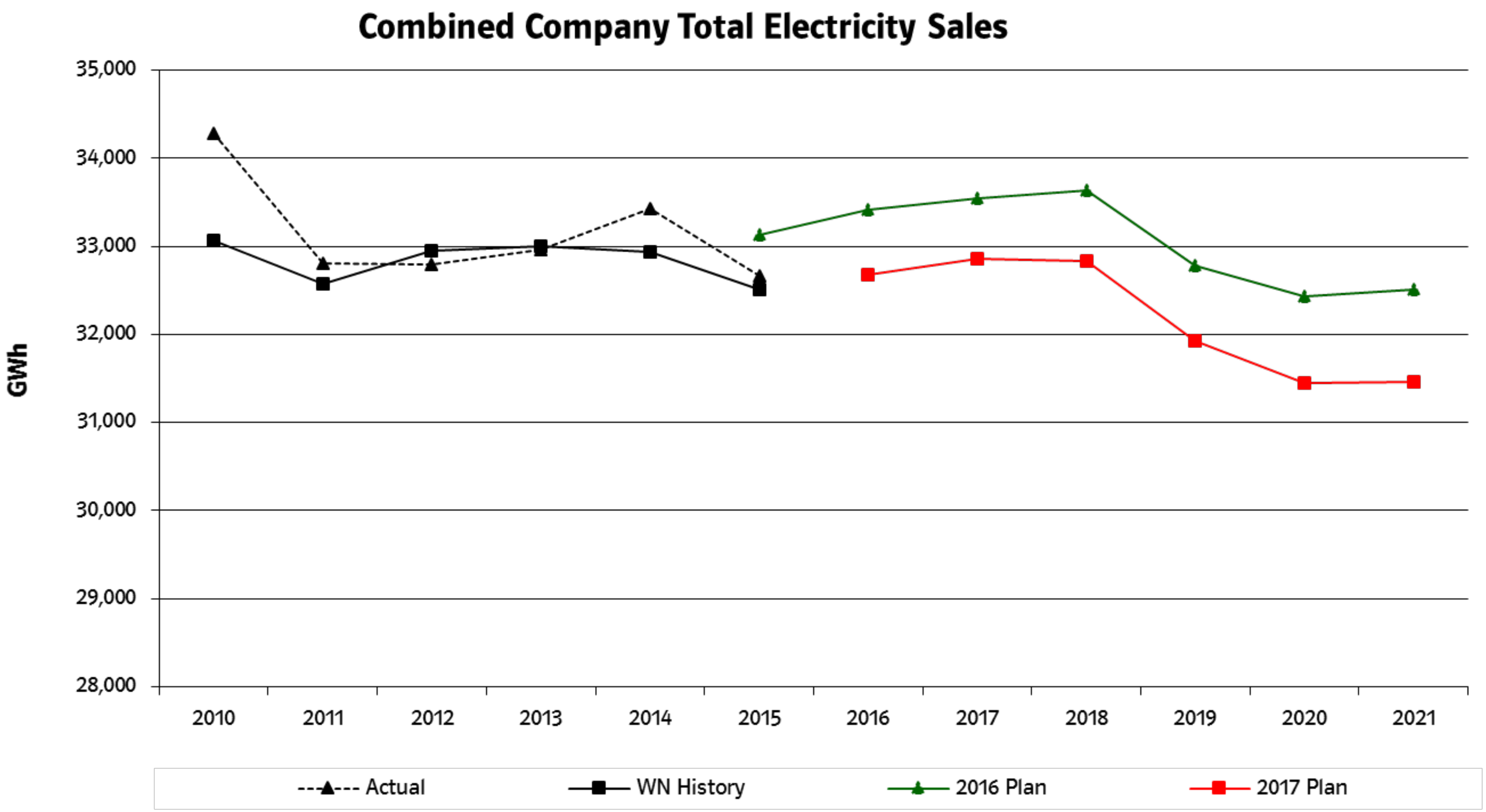
2017 Plan 2-3% lower through 2021



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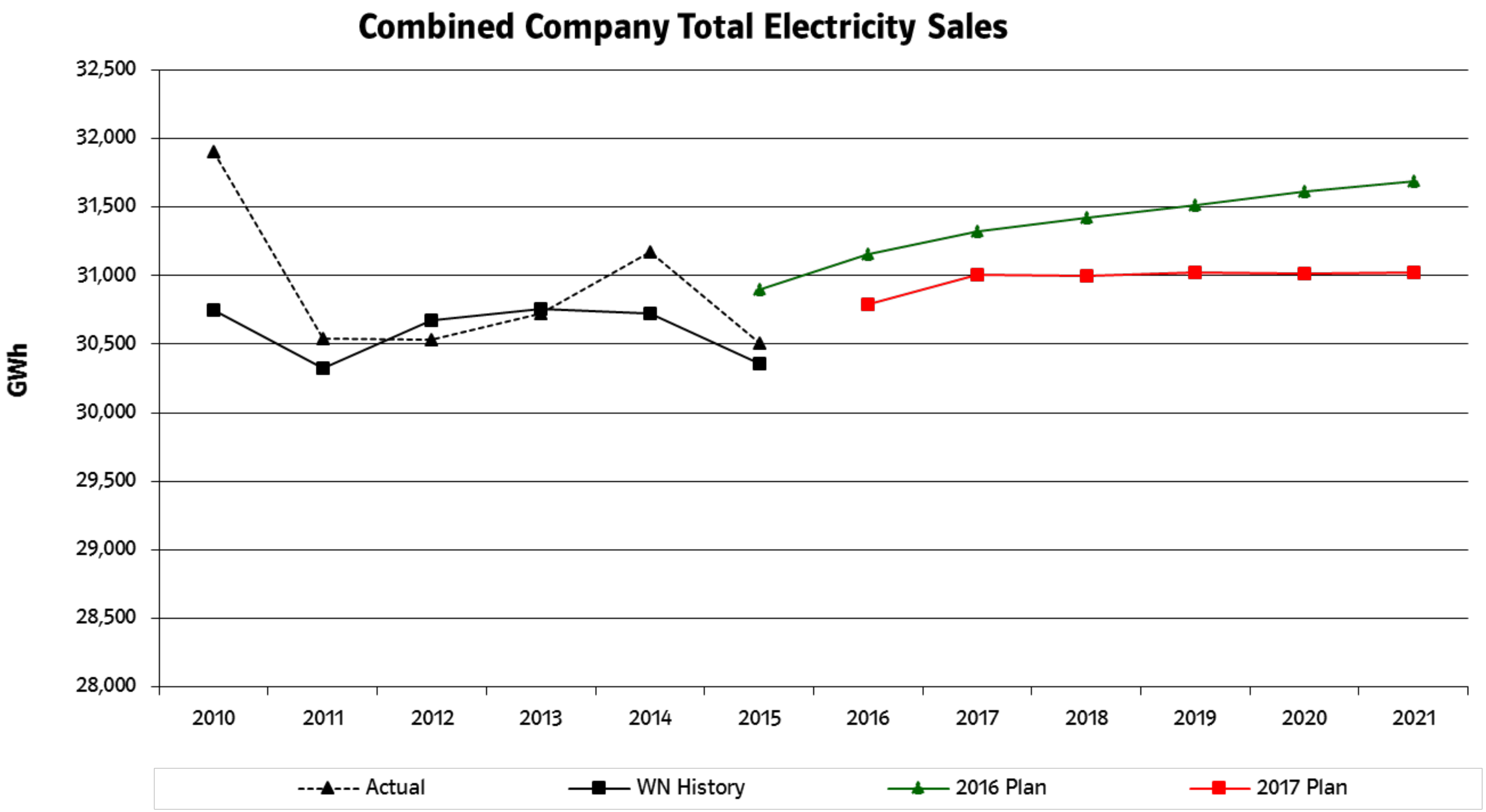
PPL companies

2017 Plan lower than 2016 Plan with slower growth



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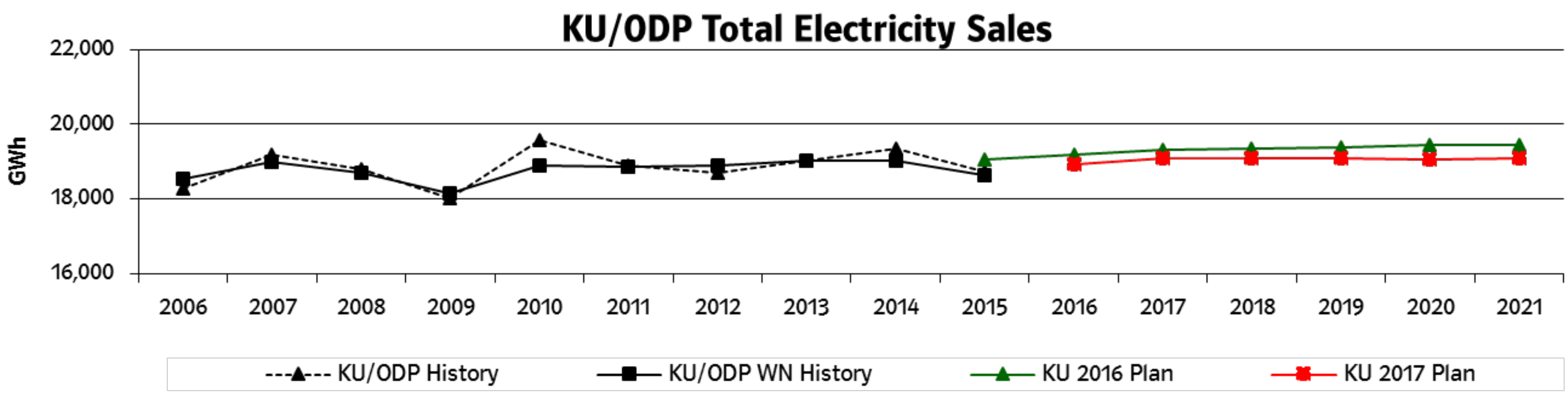
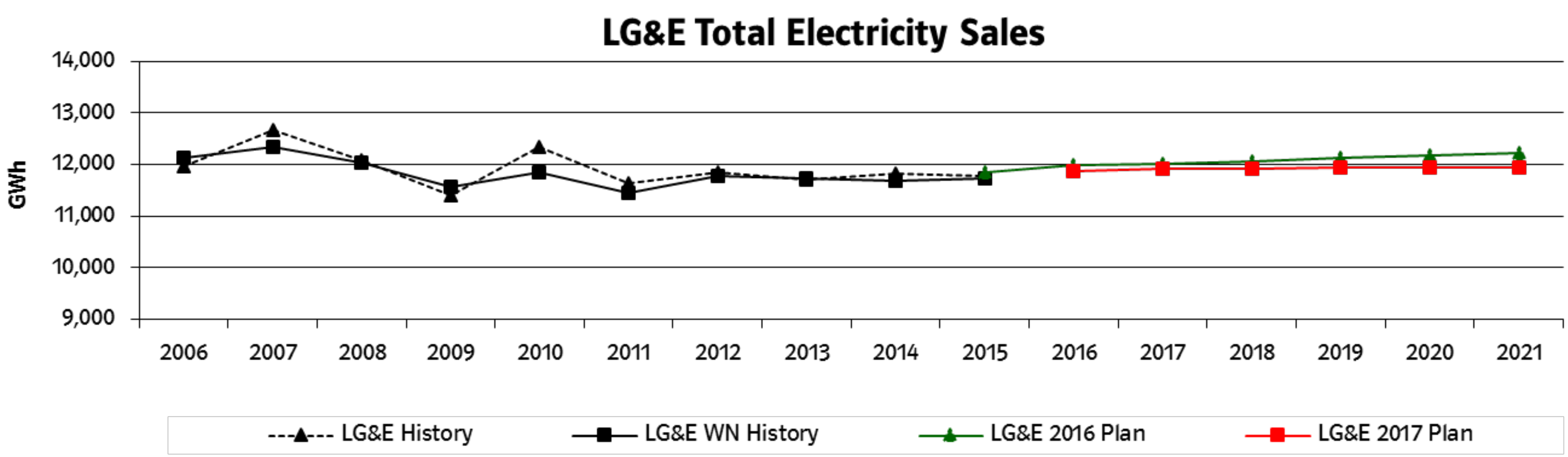
PPL companies

Sales forecasts decreased for both LG&E and KU





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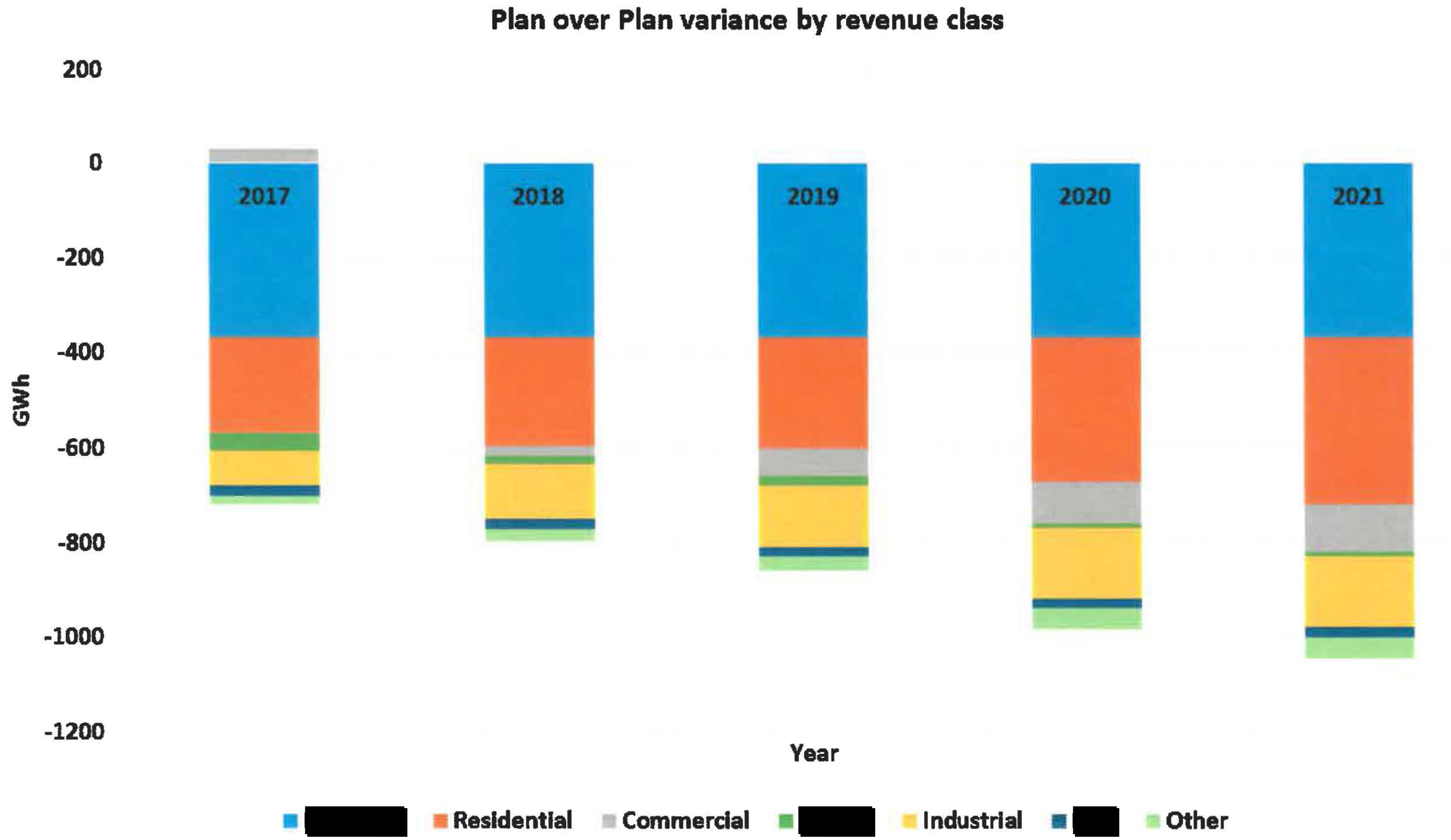
PPL companies

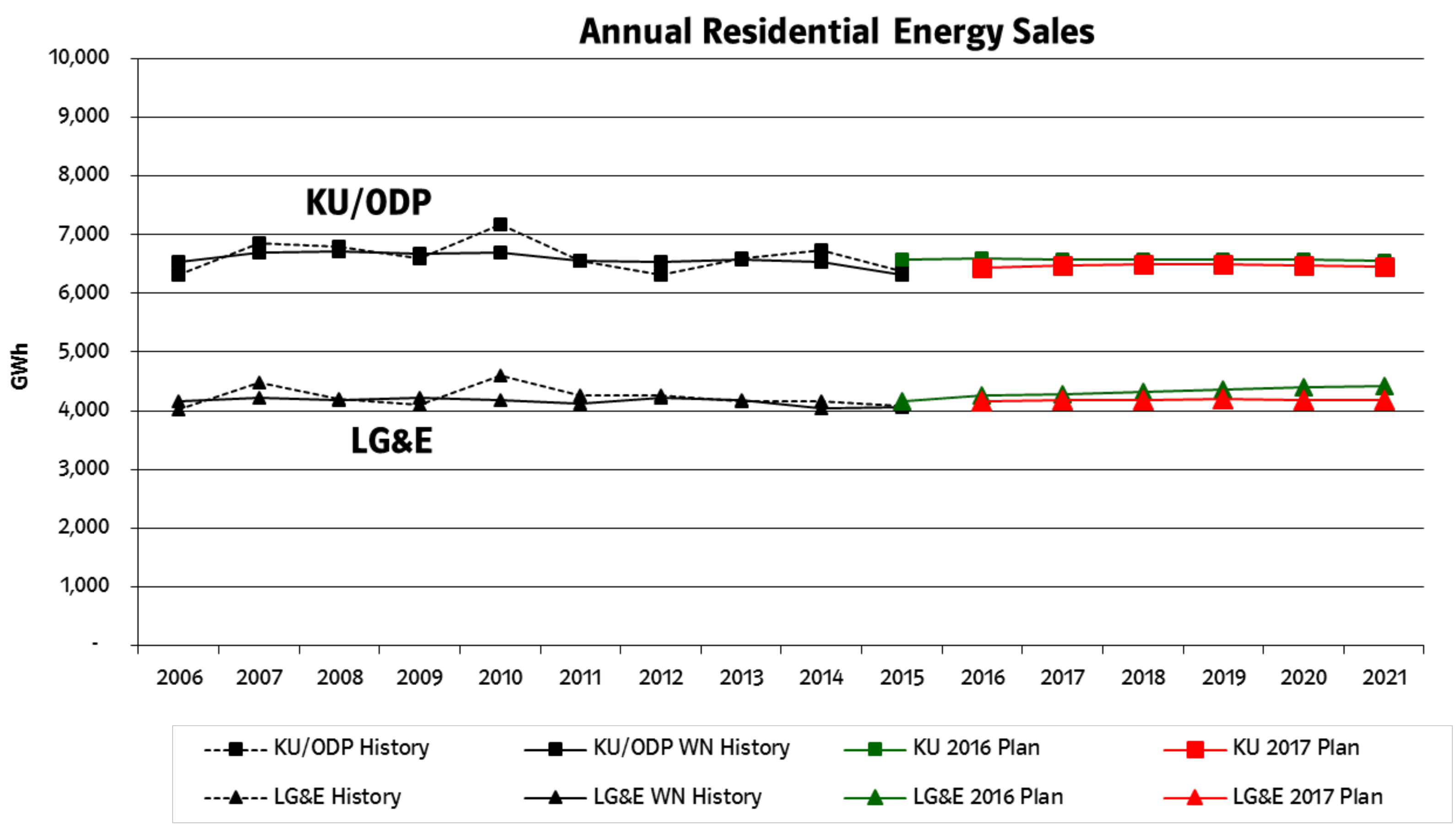
CONFIDENTIAL INFORMATION REDACTED

Loss of [redacted] and reductions to Residential and Industrial forecasts drive forecast variances



LG&E KU PPL companies

Residential Sales remain flat as increased efficiency offsets customer growth



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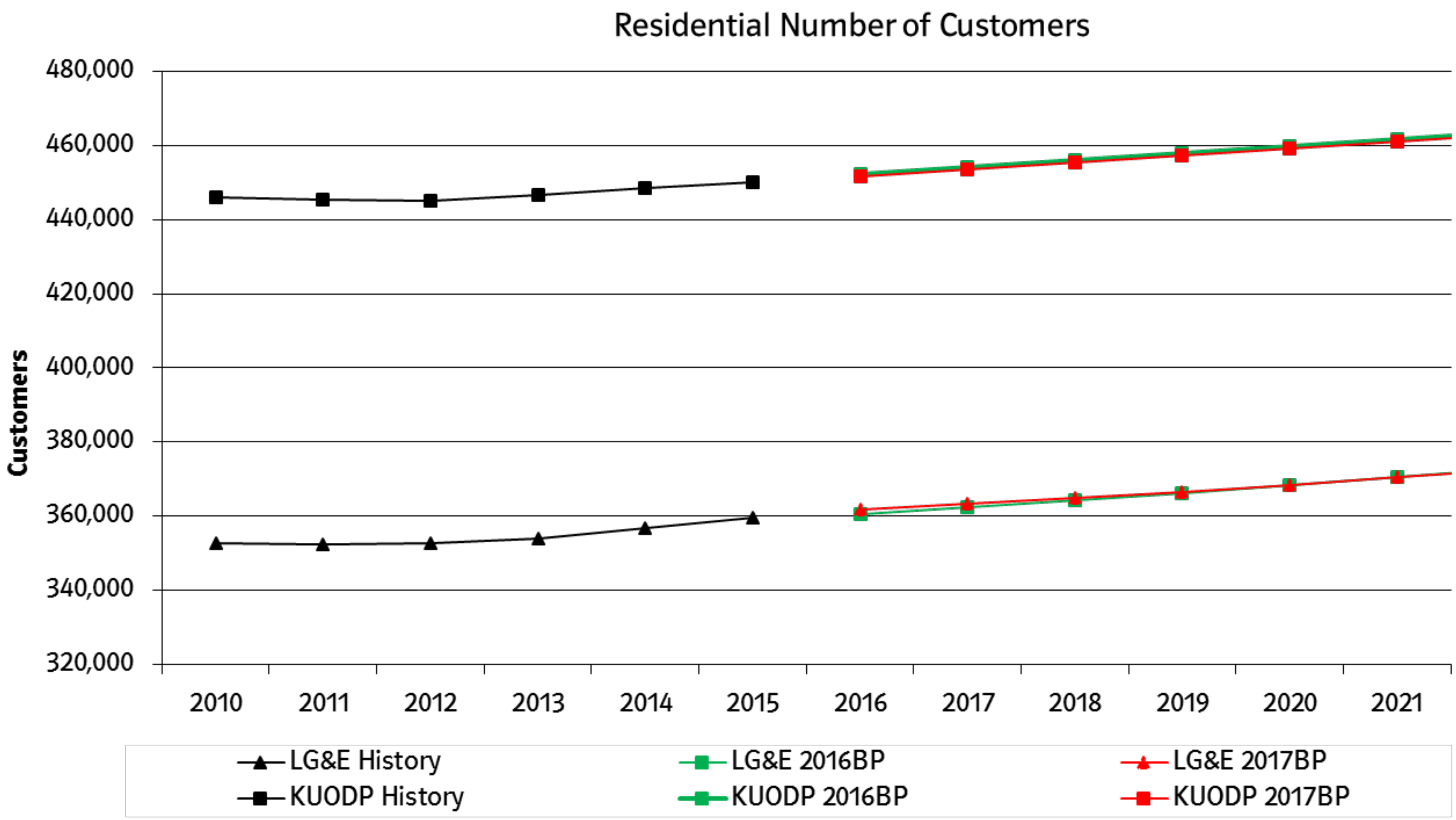
0.4% Annual Residential Customer Growth



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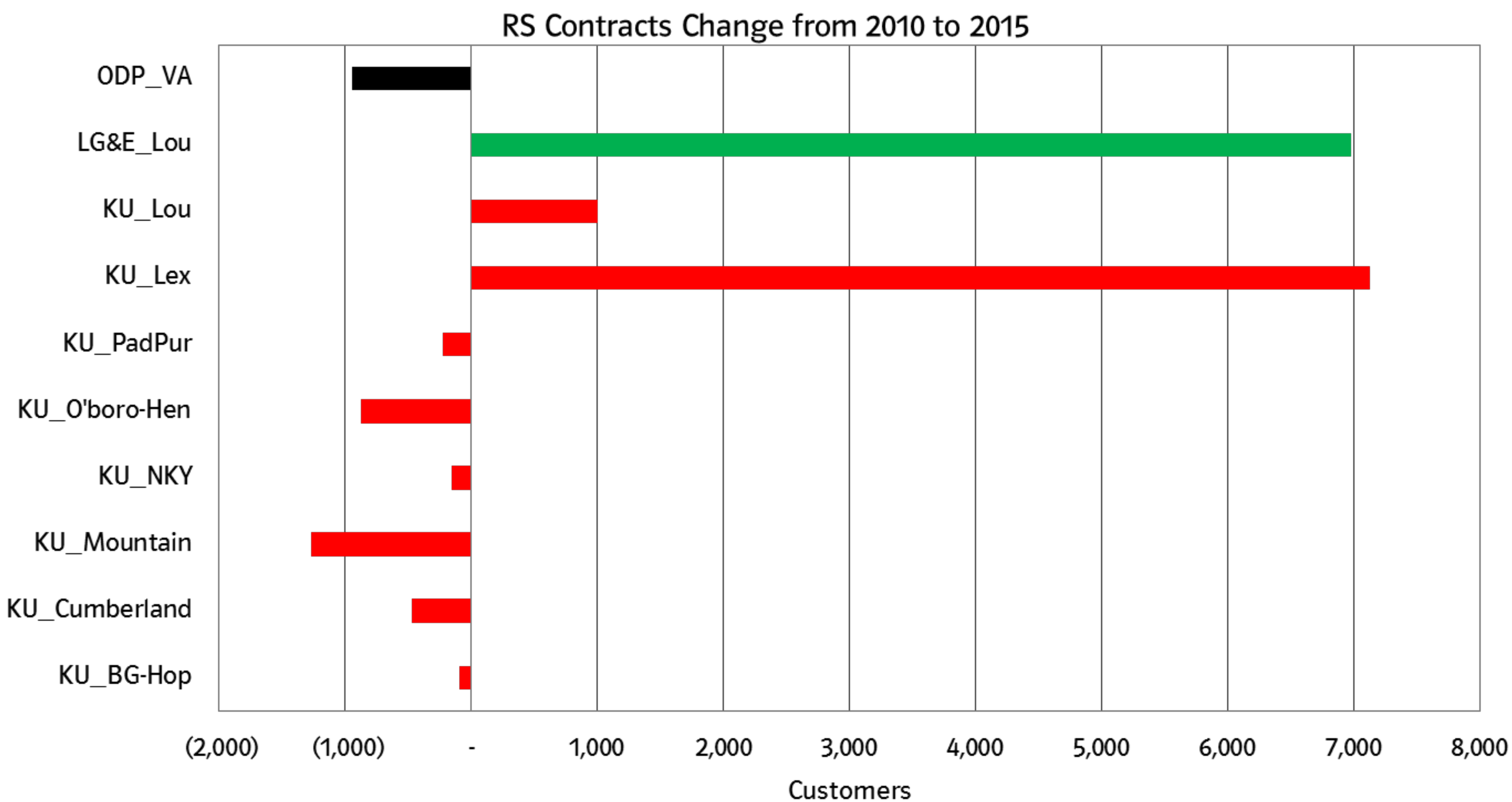
PPL companies

Residential customer growth tempered by reductions in rural regions



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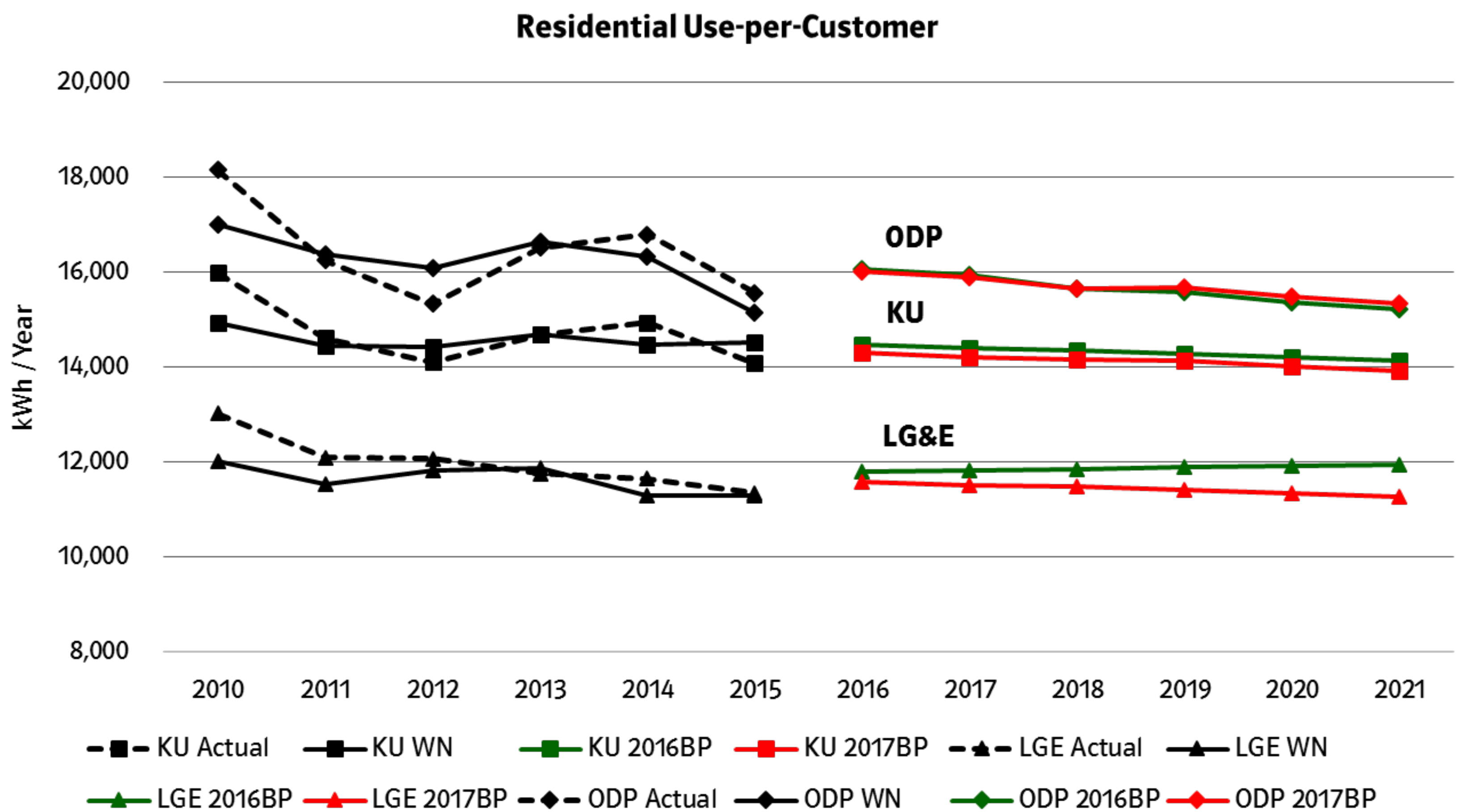
PPL companies

Consistent with history, residential usage per customer declining in all service territories



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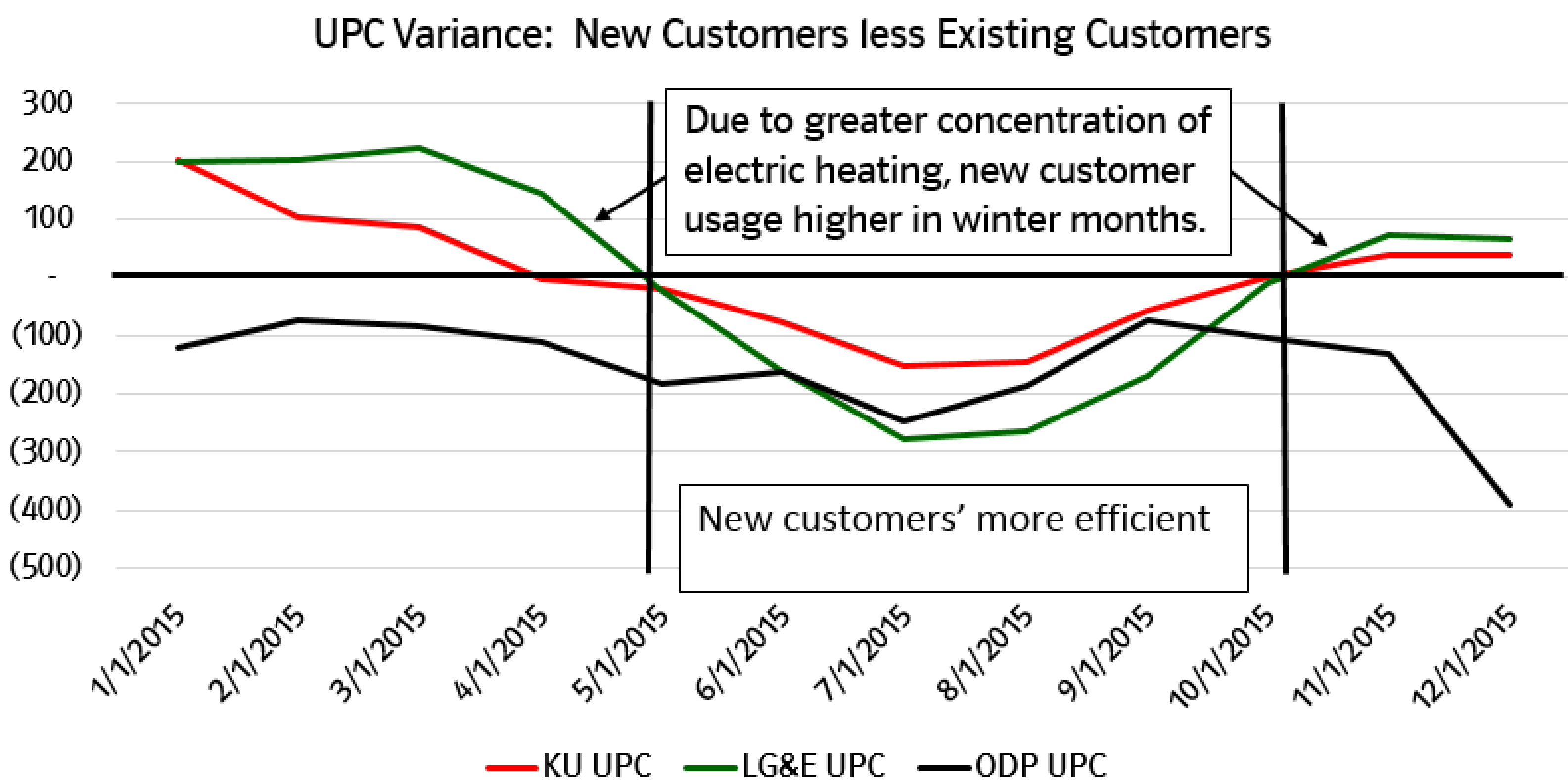
PPL companies

Electric heating offsetting efficiency impacts at LG&E



	Existing UPC	New Premise UPC	% Change
KU	14,251	14,269	0%
LG&E	11,461	11,465	0%
ODP	15,782	13,917	-12%

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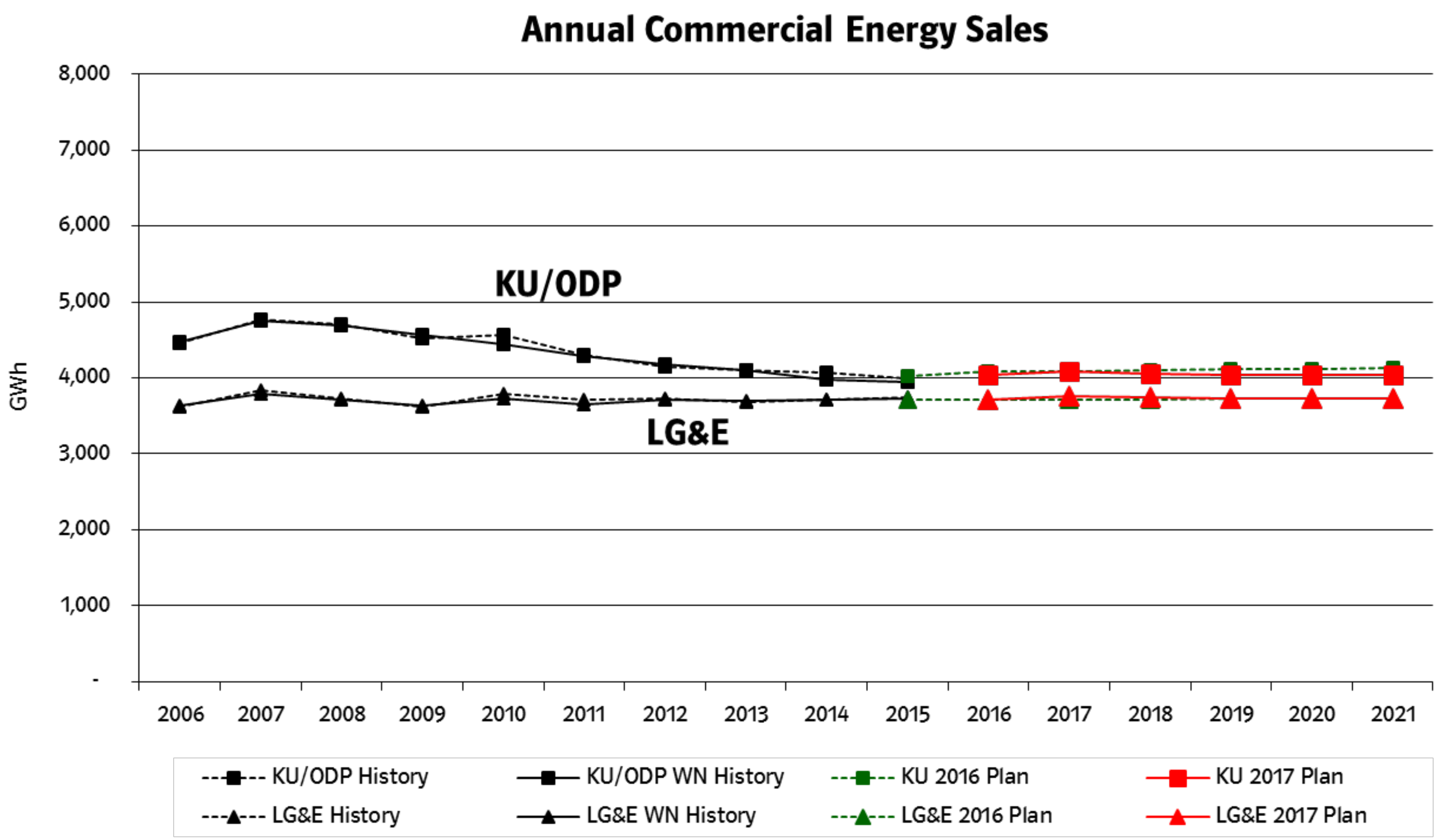
PPL companies

KU Commercial remains flat after post-recessionary decline



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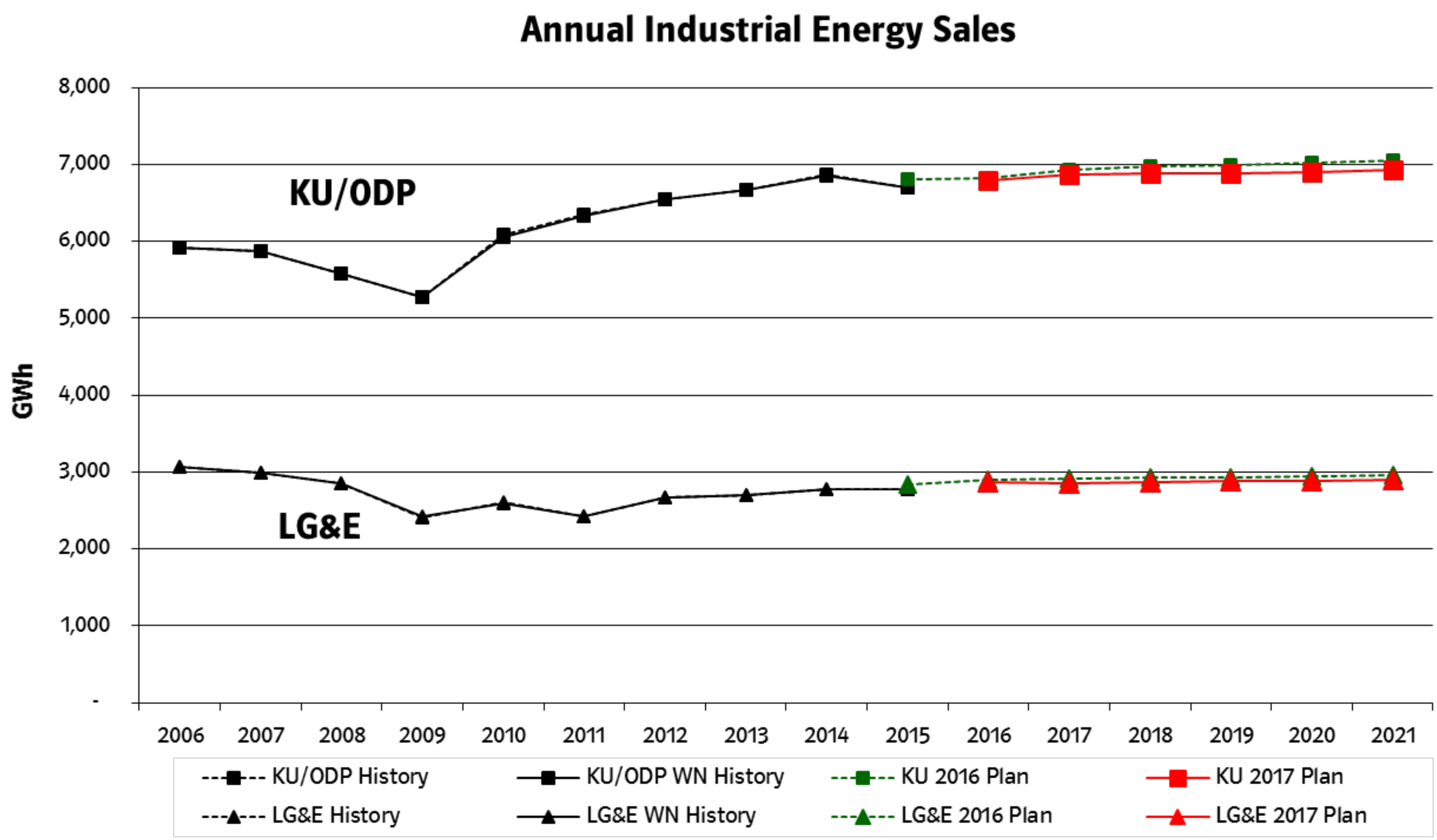
Major accounts drive short-term Industrial growth



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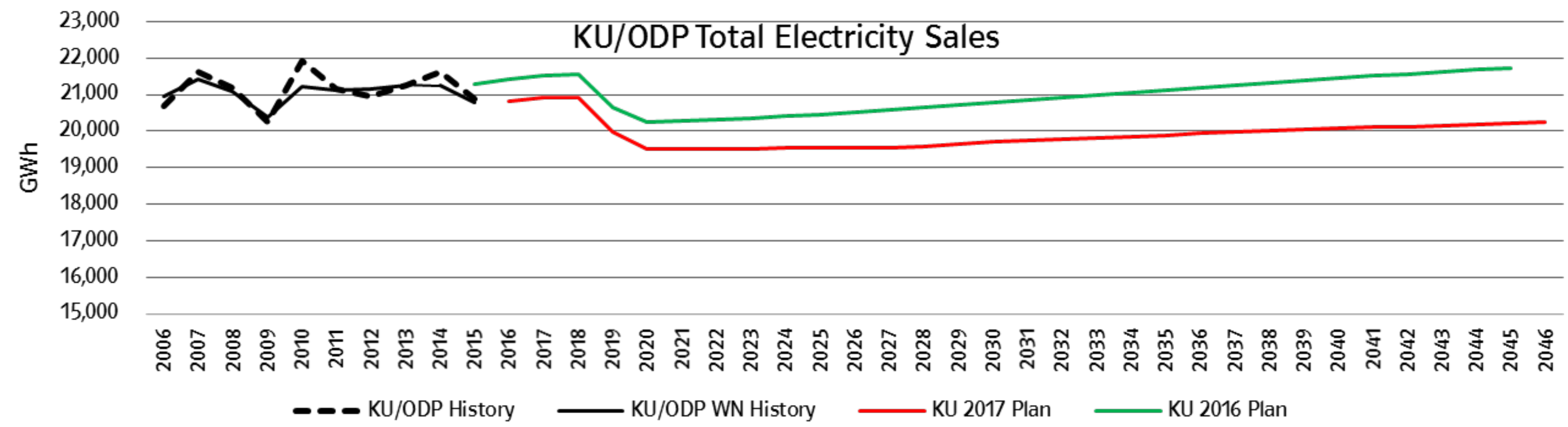
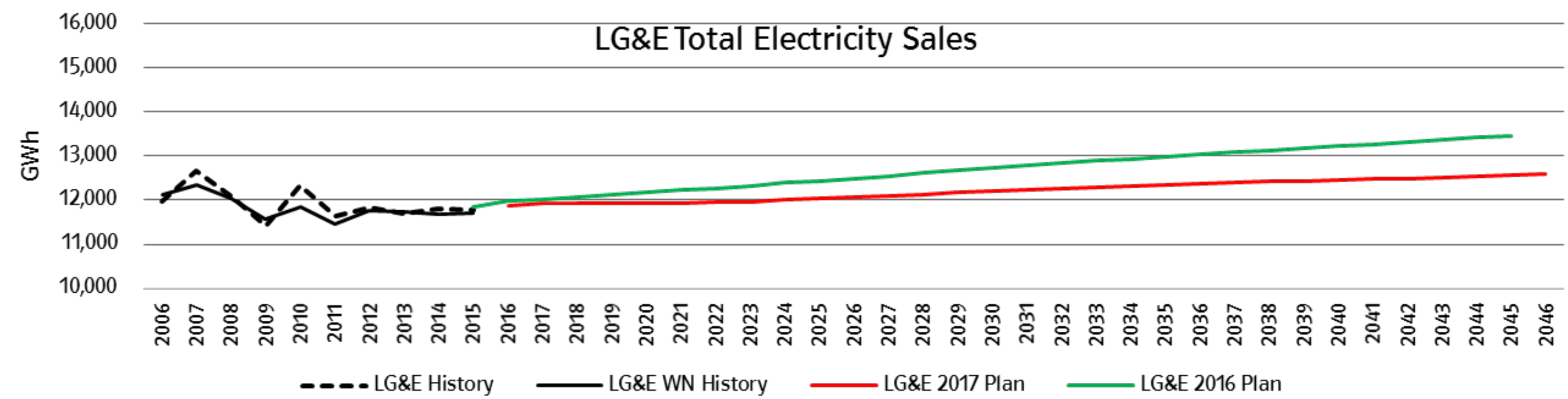
PPL companies

Consistent with national forecasts, 2017 Plan long-term growth rate is lower than 2016 Plan





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PPL companies

Downside risks likely outweigh upside risks in 2017 Plan forecast

- Downside risk
  - *Faster LED adoption*
  - *Faster coal decline*
  - *Auto industry recession*
  - *General US recession*

- Upside risk
  - *Rapid EV expansion*
  - *Major economic development*

LG&E KU PPL companies

Conclusion

- Consistent with national forecasts, 2017 Plan lower than 2016 Plan
- Modest growth in near-term due to major account expansions
- Loss of [redacted] and slower growth in Residential sales will also reduce peak demand

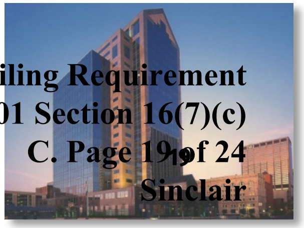
PPL companies

Appendix

7/11/2016







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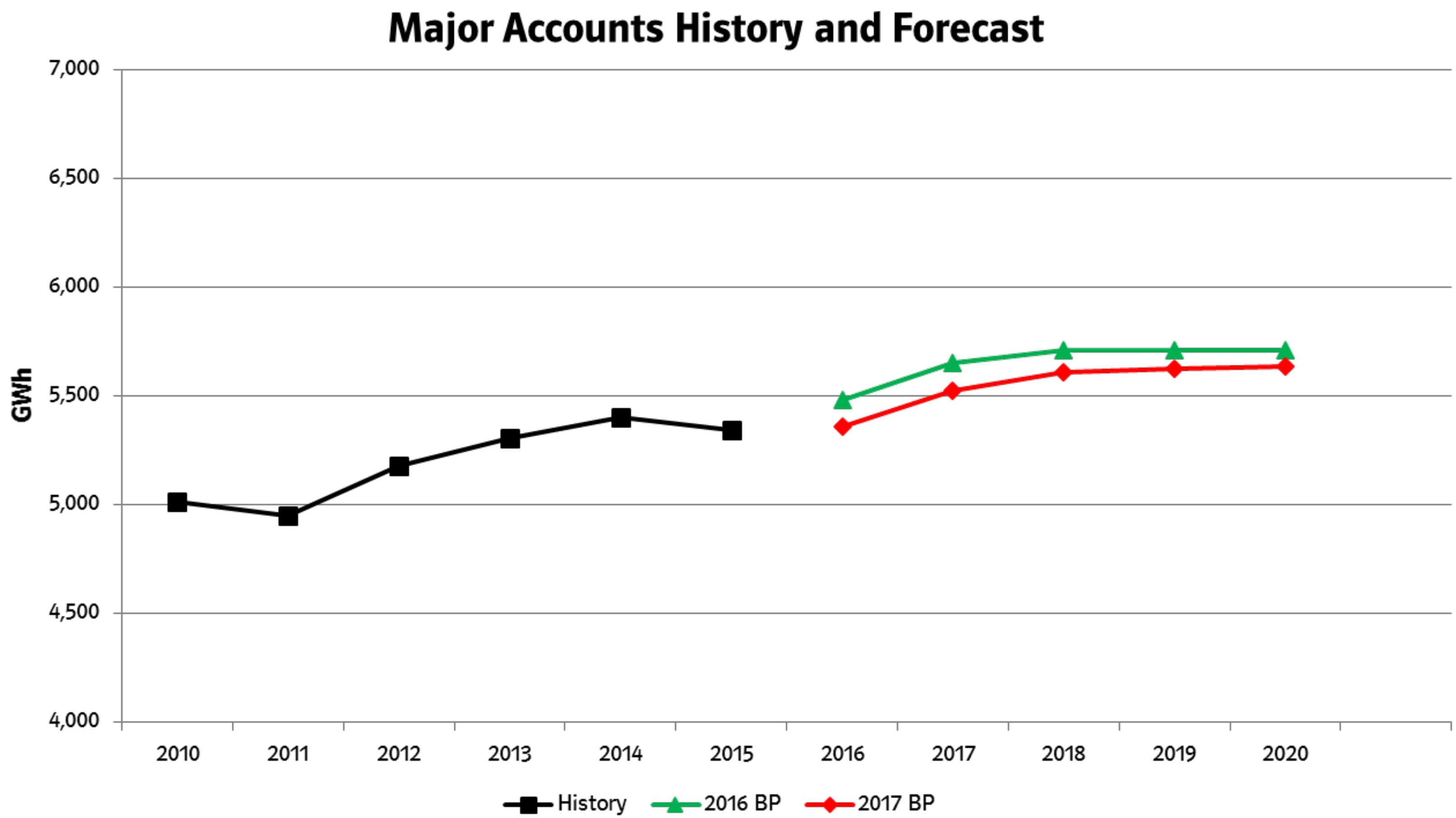
Major Accounts below 2016 Plan; growth through 2018 led by NAS and Toyota



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LG&E KU
PPL companies

Plan over plan Major Account changes in 2017

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Major Account	2017Plan (GWh)	2016 Plan (GWh)	Delta (GWh)	Notes
[redacted]	250	202	48	[redacted]
[redacted]	295	272	23	[redacted]
[redacted]	242	230	12	[redacted]
[redacted]	97	90	7	[redacted]
[redacted]	208	224	-16	[redacted]
[redacted]	56	75	-19	[redacted]
[redacted]	1,257	1,278	-21	[redacted]
[redacted]	90	117	-27	[redacted]
[redacted]	513	549	-36	[redacted]
[redacted]	232	267	-36	[redacted]
[redacted]	127	189	-62	[redacted]

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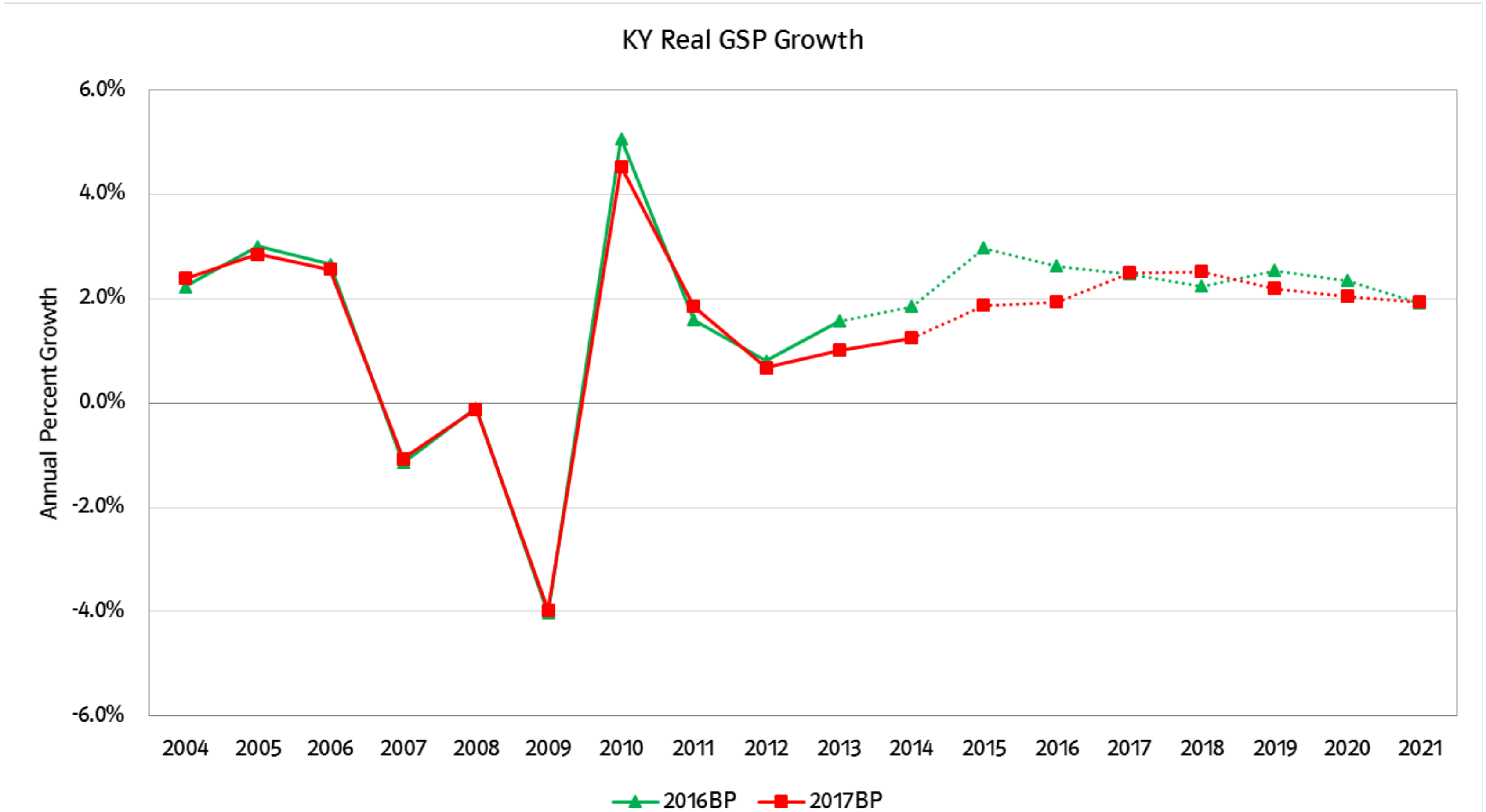
PPL companies

GSP recent history revised downwards



PPL companies

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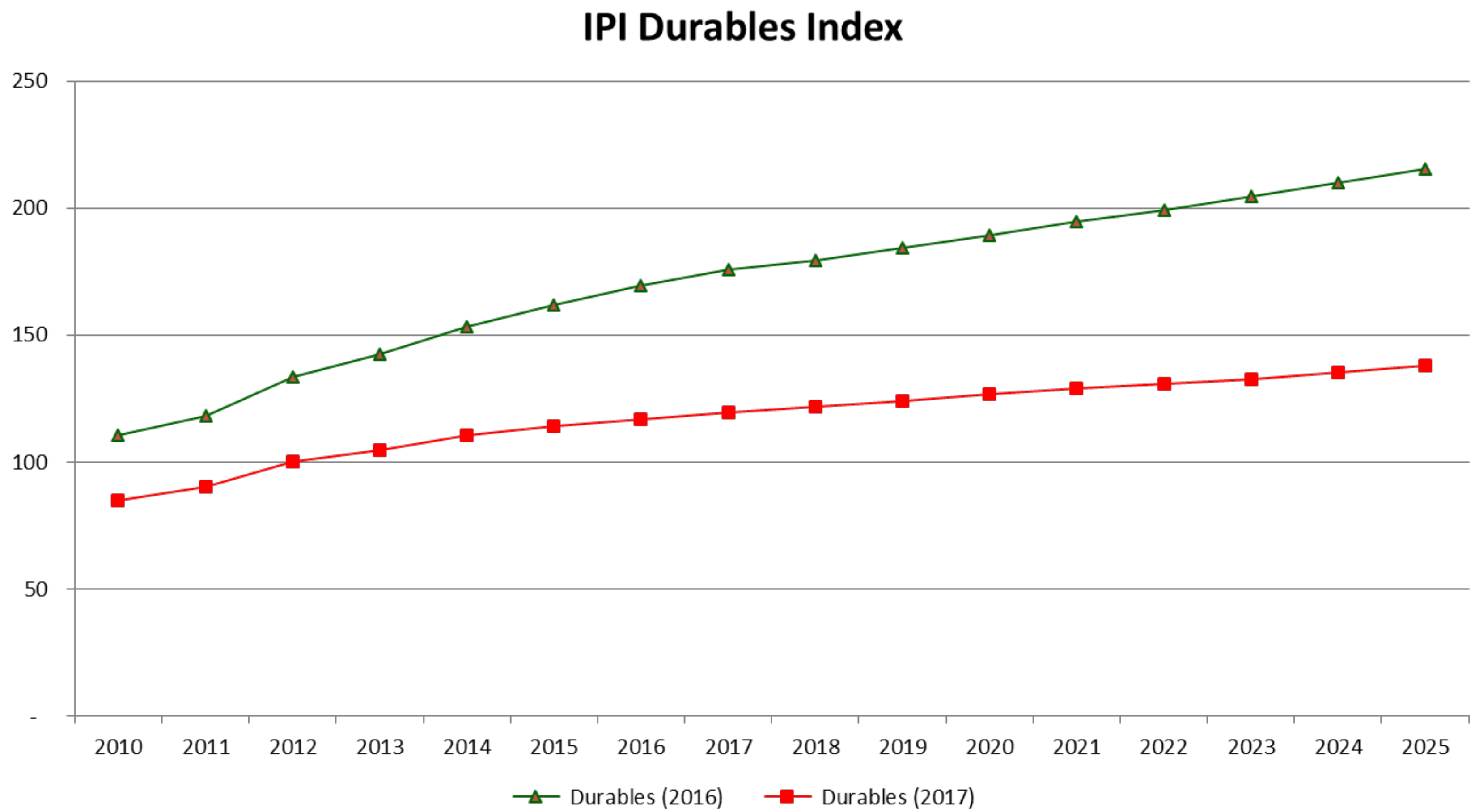
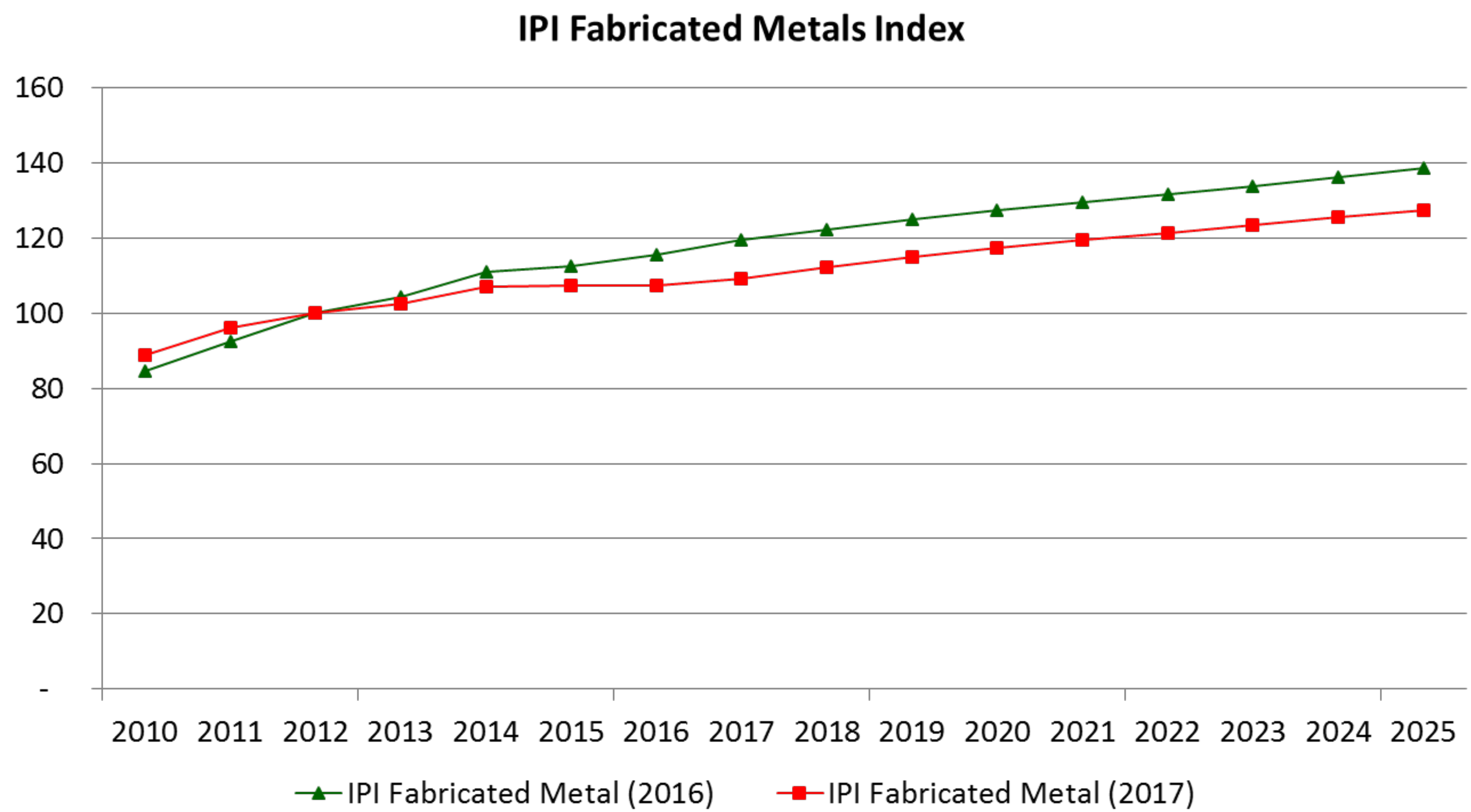
IPI Durables lower than 2016 Plan



PPL companies

Fabricated Metals Index lowered in near term



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PPL companies

Annual Natural Gas Volume Forecast Process

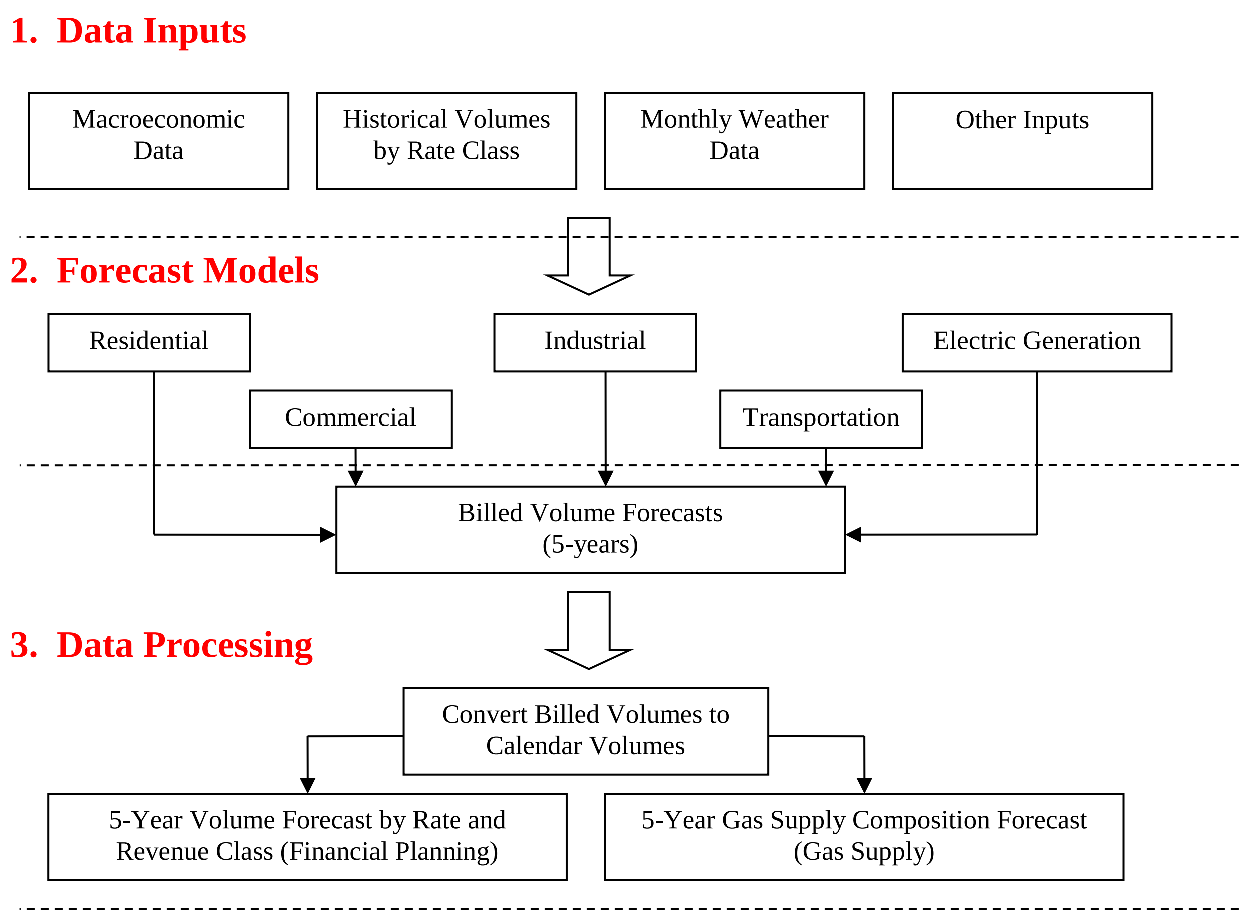
Sales Analysis & Forecasting
September 2016

Table of Contents

1 Introduction

The Sales Analysis & Forecasting group annually develops the natural gas sales and transportation forecasts for the Louisville Gas & Electric Company (LG&E). LG&E natural gas customers can broadly be classified as either sales customers or transportation customers. Furthermore, sales customers can be further divided into firm and interruptible customers. LG&E must procure gas for firm sales customers, but it has no obligation to procure gas for interruptible (AAGS) sales customers. Sales customers are grouped by residential, industrial, and commercial gas service rates. Transportation customers are large industrial and commercial customers on LG&E's distribution system who contract for their own gas supply and use the company's pipeline system to deliver gas from an interstate pipeline connection point with LG&E to their facility. These forecasts are an input to the company's revenue and gas supply expense forecast. This document describes the processes used to produce the annual volume forecasts. The forecast process can be divided into three parts (see Figure 1).

Figure 1 – Natural Gas Volume Forecast Process Diagram



The first part of the forecast process involves gathering and processing input data. The following are key inputs to the forecast process:

- Macroeconomic data
- Historical gas sales and customer data

- Weather data
- Other data, including billing cycle forecasts and residential heating appliance shares and efficiencies.

The input data is used to specify various forecast models. LG&E's natural gas volumes are forecasted by rate class as each model is used to forecast sales for a group of customers with homogeneous usage patterns within the same, or similar, tariff rates.

Most of the forecast models produce volume forecasts on a monthly billed basis.[1] In the third part of the forecast process, gas volume data from the forecast models is processed to meet the needs of the forecast end users. The monthly billed energy forecasts must first be converted to calendar month forecasts. The billed and calendar sales forecasts are allocated by rate and revenue class for the Financial Planning department.[2] In addition, the calendar forecasts are used to produce the Gas Supply Composition Forecast.

The final part of the forecast process includes validating and documenting the forecast results. To ensure the results are reasonable, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. Each of these steps is discussed in more detail in the following sections.

[1] All customers are assigned to one of 20 billing cycles. A billing cycle determines what time of the month a customer's meter is read. Because most billing cycles do not coincide precisely with the boundaries of calendar months, most customers' monthly bills will include energy that was consumed in multiple calendar months. The energy on customers' bills is referred to as "billed" energy.
[2] Rate class defines the tariff assigned to each customer meter while Revenue class is a higher level grouping; a Revenue class consists of one or more rate classes.

2 Input Data

Table 1 provides a summary of the data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

Table 1 – Volume Forecast Data Inputs

Data	***Source***	***Format***
State Macroeconomic Data (Employment, Wages)	IHS Global Insight	Annual or Quarterly by County – History and Forecast
State Demographic Data (Households, Personal Income, Population)	IHS Global Insight & Kentucky Data Center	Annual or Quarterly – History and Forecast
National Macroeconomic Data (Industrial Production Index)	IHS Global Insight	Annual or Quarterly – History and Forecast
Weather	NOAA's National Climatic Data Center (NCDC)	Daily HDD/CDD by Weather Station – History
Historical Gas Supply Cost	State Regulation and Rates	Monthly
Henry Hub Gas Price Forecast	Corporate Long-term Planning Process	Monthly
Gas Supply Cost Forecast	Gas Supply (based on Henry Hub Gas Price Forecast)	Monthly
Historical Billing Cycle Meter Reading Schedule	Revenue Accounting	Billing Cycle Read Dates
Heating Appliance Efficiencies	US Energy Information Administration (EIA)	Annual Efficiencies by Appliance (Furnace, Water Heater)
Residential End-Use Data	EIA, LG&E Residential End-Use Survey	Appliance Saturations
Commercial End-Use Data	EIA, LG&E Commercial End-Use Survey	Appliance Saturations
Billed Sales History by Rate Class	CCS Billing System	Monthly
Number of Customers History by Rate Class	CCS Billing System	Monthly
Individual Customer Usage History	CCS Billing System	Monthly
Forecasts of Gas Used by Electric Generation	Generation Planning	Monthly

2.1 Service Area-Specific Macroeconomic Forecasts

LG&E's natural gas service area includes all or portions of 17 Kentucky counties.[3] IHS Global Insight produces forecasts of macroeconomic drivers by county and industry. Service area-specific macroeconomic forecasts are created by aggregating the county-specific forecasts for the counties in LG&E's service area.

2.2 Software Tools

The following software packages are used in the forecast process:

- Microsoft Office: Excel, PowerPoint, Access
- SAS
- R
- Itron Metrix ND

2.3 Billed Usage History

Historical billed usage volumes for all retail customers are taken from the LG&E Customer Care System (CCS). The LG&E Billed Transport Report contains historical usage volumes for all transportation customers. Transportation customers nominate – on a daily basis – the amount of gas they expect to consume. A daily or monthly "imbalance" is computed as the difference between the amount of natural gas actually consumed and the amount of natural gas nominated.

For several classes, a significant portion of the total gas usage is made up of gas consumed by heating appliances (e.g., gas furnaces and gas water heaters). Heating appliance usage is a function of appliance efficiencies and the weather. As appliance efficiencies improve over time, the average use-per-customer – for a given class and temperature – will decline in the absence of customers' behavioral changes.

The heating appliances that consume the most natural gas are the gas furnace and gas water heater. Total usage and efficiency data for these appliances are provided by the US Energy Information Administration (EIA) and are used as inputs into some of the forecast models.

2.4 Processing of Weather Data

Weather is a key explanatory variable in the gas forecast models. The weather dataset from the National Oceanic & Atmospheric Administration's (NOAA) National Climatic Data Center (NCDC) contains temperatures (maximum, minimum, and average), heating degree days (HDD), and cooling degree days (CDD) for each day and weather station over the past 30 years. This data and the Company's meter reading schedule are used to create (a) a historical weather series by billing month and (b) a forecast of "normal" weather by billing month.[4] Each of these processes is summarized below.

[3] LG&E is the only gas utility serving Bullitt, Henry, Larue, Meade, Nelson, Oldham, Spencer and Trimble counties. LG&E also serves parts of Barren, Green, Hardin, Hart, Jefferson, Marion, Metcalfe, Shelby and Washington counties.
[4] "Normal" weather is defined as the average weather over a historical period. The Companies do not attempt to forecast any trends in weather.

2.4.1 Historical Weather by Billing Month

The methodology used to create the historical weather series by billing month consists of the following steps:

1. Using the historical daily weather data from the NCDC, sum the HDD and CDD values by billing cycle.[5] Each historical billing month consists of 20 cycles. The Company's historical meter reading schedule contains the beginning and ending date for each billing cycle.
2. Average the billing cycle total HDDs and CDDs by billing month.

2.4.2 Normal Weather Forecast by Billing Month

The methodology used to produce the forecast of normal weather by billing month includes the production of a daily forecast of normal weather. The methodology used to develop the daily forecast (summarized in Steps 2-5) is consistent with the methodology used by the NCDC to create its daily normal weather forecast.[6] The following steps are used to create the forecast of normal weather by billing month:

1. Compute the forecast of monthly weather by *calendar* month by averaging the monthly degree-day values and over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 30-year historical period. Therefore, the normal HDD value for January is the average of the 30 January HDD values in this period.
2. Compute "unsmoothed" daily normal weather values by averaging temperature, HDDs, and CDDs by calendar day. The unsmoothed normal temperature for January 1, for example, is computed as the average of the 30 January 1 temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered about the desired day. The "smoothed" normal temperature for January 1, for example, is computed as the average of the unsmoothed daily normal temperatures between December 16 and January 15.
4. Manually adjust the integer values in Step 3 so that the following criteria are met:
   a. The monthly average temperature – computed by averaging the daily temperatures by month and rounding to the nearest integer – should match the normal monthly temperatures in Step 1.
   b. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
   c. The daily temperatures and CDDs should be monotonically increasing from winter to summer and monotonically decreasing from summer to winter. The daily HDD series should follow a reverse trend.

   These criteria ensure the daily normal series is consistent with the monthly normal series.
5. The Company's forecasted meter reading schedule contains the beginning and ending date for each billing cycle through the end of the forecast period. In this step, sum the HDD and CDD values by billing cycle. Use the February 28 weather data as a proxy for February 29 when billing cycles include leap days.
6. Average the billing cycle totals by billing month.

[5] Weather data in the gas forecast is taken from the weather station at Standiford Field Airport (SDF) in Louisville.
[6] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

2.5 Forecasts of Gas Used by Electric Generation

Effective May 1, 2008, LG&E and KU's electric generation business entered into a special contract ("Electric Generation Special Contract") with LG&E's gas distribution business for gas sales and transportation services. Under the contract, the Cane Run and Mill Creek generating stations are served as a firm sales customer and the Paddy's Run generating station is served as a transportation customer. Since September 2014, Cane Run has taken gas directly from Texas Gas at a new interconnection point built for the Cane Run natural gas combined cycle plant and is no longer served by the LG&E Gas Business.

The forecasts of gas used by each of the aforementioned generating stations are provided by the Generation Planning group. In addition, the Generation Planning group provides a forecast of gas used by the Zorn generating station, which is also served via the LG&E gas distribution system (but not as a part of the Electric Generation Special Contract).

From a revenue accounting perspective, the gas consumed by the Mill Creek station is accounted for in a separate Interdepartmental Sales revenue class. The gas consumed by the Paddy's Run station is accounted for in the Interdepartmental Transport revenue class. The gas consumed by the Zorn station is considered Company Use and is recorded in the utility financial reports as part of gas 'Used in Electric Generation.'

3 Forecast Models

LG&E natural gas customers can broadly be classified as either sales customers or transportation customers. Sales customers include customers on the residential, industrial, and commercial gas service rates. Transportation customers are large industrial and commercial customers on LG&E's distribution system who contract for their own gas supply. Each forecast is discussed in detail in the following sections.

3.1 Residential Forecast

The residential forecast consists of all customers on the Residential Gas Service (RGS) rate schedule. The RGS class accounts for approximately half of the total volume forecast. RGS sales are forecasted as the product of a customer forecast and a use-per-customer forecast.

3.1.1 Residential Gas Service (RGS) Customer Forecast

The RGS customer forecast is modeled as a function of the number of forecasted households in the LG&E service territory. Household and population data by county and Metropolitan Statistical Area (MSA) are available from IHS Global Insight and the Kentucky Data Center.

3.1.2 Residential Gas Service (RGS) Use-per-Customer Forecast

The RGS use-per-customer forecast is developed using a Statistically-Adjusted End-Use (SAE) model (similar to what is used to forecast residential electric sales). Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. For natural gas, the SAE approach defines energy use as a function of energy used by heating equipment and other natural-gas fueled equipment.

$$\text{Use-per-Customer} = a_1\text{*XHeat} + a_2\text{*XOther}$$

The heating and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and the gas supply cost. In addition, certain binary variables may be added to compensate for anomalies in the data or other events. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A discussion of each of these components and the methodology used to develop them is contained in Appendix A.

3.2 Commercial Forecast

The commercial forecast is comprised of customers on the Firm Commercial Gas Service (CGS) and Commercial As-Available Gas Service (CAAGS) rate schedules. Given the unique characteristics of these classes, each class is modeled separately. CGS volumes are forecasted as the product of a customer forecast and a use-per-customer forecast.

3.2.1 Firm Commercial Gas Service (CGS) Customer Forecast

The CGS customer forecast is modeled based on its own historical trend independent of the number of RGS customers.

3.2.2 Firm Commercial Gas Service (CGS) Use-per-Customer Forecast

Similar to the RGS use-per-customer forecast, the CGS volume forecast is developed using an SAE model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

$$\text{Use-per-Customer} = \text{a1*XHeat} + \text{a2*XOther}$$

The heating and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and the gas supply cost. Once the historical profile of these explanatory variables is established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable (volumes). A discussion of each of these components and the methodology used to develop them is contained in Appendix B.

3.2.3 Commercial As-Available Gas Service (CAAGS) Forecast

CAAGS sales are forecasted as a portion of total As-Available gas sales. The forecast of CAAGS volumes is modeled as a function of weather, natural gas prices, and number of customers.

3.3 Industrial Forecast

The industrial revenue class is comprised of customers on the Firm Industrial Gas Service (IGS) and Industrial As-Available Gas Service (IAAGS) rate schedules.

3.3.1 Firm Industrial Gas Service (IGS) Forecast

IGS volumes are forecasted in total as a function of natural gas prices, number of customers, and a rate-specific industrial production index.

3.3.2 Industrial As-Available Gas Service (IAAGS) Forecast

IAAGS sales are forecasted as a portion of total As-Available gas sales. The forecast of IAAGS volumes are modeled as a function of weather, natural gas prices, and number of customers.

3.4 Interdepartmental Sales Forecast

The interdepartmental sales forecasts consist of gas used by the Mill Creek generating station. The forecast of gas used by these stations is based on usage over the last twelve months in conjunction with the Generation Planning group.

3.5 Firm Transportation Forecast

The firm transportation forecast consists of special contract customers and customers on the Firm Transportation Service (FT) rate schedule. The firm transportation revenue class consists of the company's largest natural gas customers. For forecasting purposes, the largest commercial and industrial customers in this class are forecasted separately. These forecasts are developed by the Sales Analysis & Forecasting department with input from Major Account representatives to make sure the underlying assumptions and forecasted volumes are reasonable.

3.5.1 Industrial Special Contract (ISP) Forecast

LG&E has one industrial special contract gas customer. The inputs to this forecast are provided by the Major Accounts department.

3.5.2 Industrial Firm Transportation (IFT) Forecast

The largest customers in the IFT class make up about two-thirds of the class's total usage and are forecasted with direct input from account managers. Volumes for the other customers are forecasted in total as a function of heating degree days, gas supply cost, industrial production indices, and binary variables to account for anomalies in the data.

3.5.3 Commercial Firm Transportation (CFT) Forecast

CFT volumes are forecasted as a function of heating degree days, economic indices, and binary variables to account for anomalies in the data.

3.6 Rider TS-2 Transportation Forecast

The TS-2 transportation forecast consists of commercial and industrial customers with a Gas Transportation Service (TS-2) rider. The rate forecast is the sum of projections for individual customers that are expected to be on the rate in any given period.

3.7 Interdepartmental Transport Forecast

The interdepartmental transport forecast consists of gas used by the Paddy's Run generating station. The forecast of gas used by this station is provided by the Generation Planning group.

4 Data Processing

The models discussed in the preceding section produce forecasts on a "billed" basis. All customers are assigned to one of 20 billing cycles. A billing cycle determines what time of the month, generally, a customer's meter is read. The volumes on customers' bills are referred to as "billed" volumes. If a customer's billing cycle does not coincide directly with the boundaries of calendar months, that customer's bill will include volumes from multiple calendar months.

In this part of the forecast process, the billed forecast data is processed to meet the needs of the forecast's end users. First, the billed forecasts are converted from a billed basis to a calendar month basis. Then, the calendar forecasts are allocated by rate and revenue class for use by the Financial Planning Department. In addition, the calendar forecasts are used – along with forecasts of gas losses and gas used by company-owned facilities and generating assets – to produce the Gas Supply Composition Forecast. Each of these processes is discussed in the following sections.

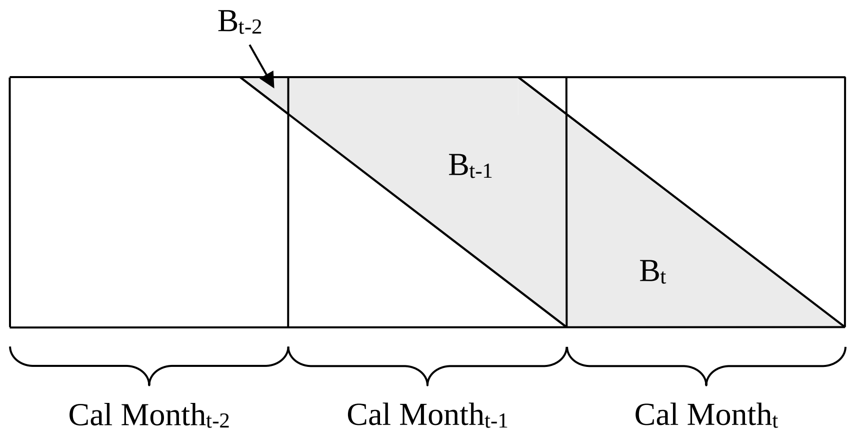
4.1 Billed-to-Calendar Conversion

The following forecasts must be converted from a billed to calendar basis: RGS, CGS, and IGS. The remaining forecasts are billed at the end of each calendar month; thus, their "billed" volumes are already stated on a "calendar month" basis and a billed-to-calendar conversion is not necessary.

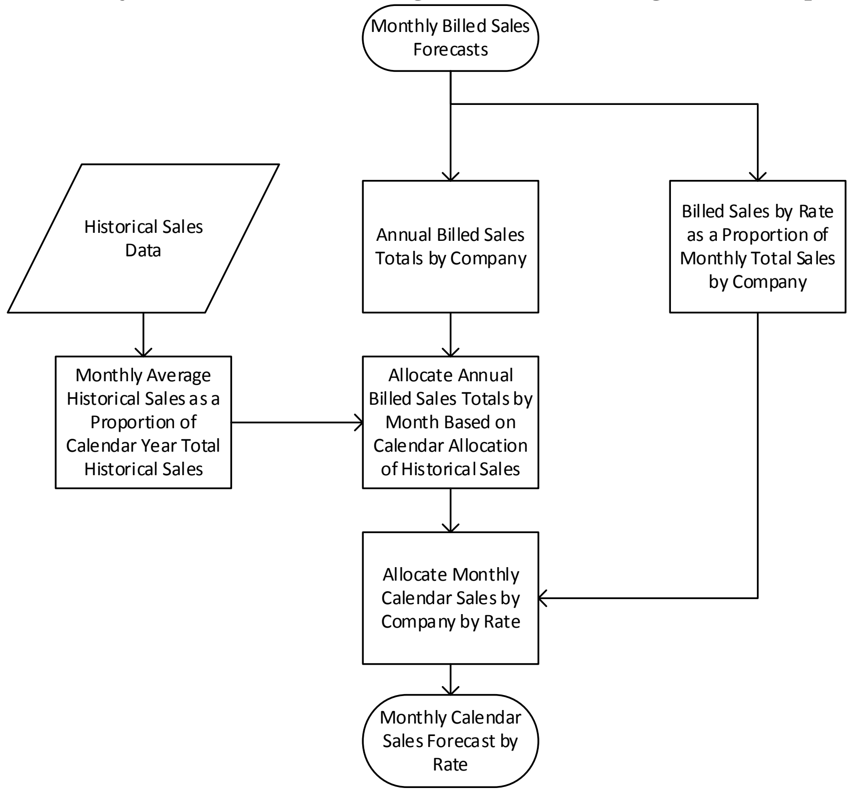
The shaded area in Figure 2 represents a typical billing month (B). Area B_t represents the volumes in the billing month that were consumed in the current calendar month (time = t). Area B_{t-1} represents the volumes in the billing month that were consumed in the previous calendar month (time = t-1). Area B_{t-2} represent the volumes in the billing month that were consumed in the calendar month two months prior to the current month (time = t-2).[7] In this process, ratios of historical monthly calendar sales by revenue class to annual monthly calendar sales by revenue class are developed to allocate forecasted billed sales to calendar sales.

[7] Not all billing months include volumes that were consumed in the calendar month two months prior to the current month.

Figure 2 – Billed and Calendar Energy



Using historical calendar data to obtain monthly allocation ratios, the annual billed sales forecasts are allocated into months using the monthly allocation ratios. This yields monthly calendar sales forecasts. These monthly calendar sales are then allocated into rate categories (i.e., tariffs) using the ratio of billed sales by rate to total sales. Figure 3 shows a diagram of the process.



4.2 Rate-to-Revenue Class Allocation

To meet revenue forecasting requirements, the billed and calendar volume forecasts, which are initially developed by rate class, must be allocated to revenue classes. Revenue class is a higher level grouping; all rate classes are allocated to one or more of the following revenue classes (see Appendix C):

- Residential
- Commercial
- Industrial
- Interdepartmental
- Transport

This information is used by the Financial Planning department to develop a forecast of revenues for the planning period. Billed and calendar forecasts are allocated to revenue classes using a set of monthly allocation ratios. These ratios are derived based on historical sales data from CCS for gas volumes and customers.

4.3 Customer Forecasts

The customer forecasts are used in the company's revenue forecast to compute revenue from customer charges.

The customer charge for the CGS and IGS rate plans varies based on the capacity of the customer's meter – whether it's less than or greater than 5,000 cf/hr. Therefore, information from CCS is used to segment the total number of CGS and IGS customers into these two meter capacity categories.

Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. Econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to identify and isolate the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly incorporating trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_{m} = a + b_1 \times \mathrm{XHeat}_{m} + b_2 \times \mathrm{XCool}_{m} + b_3 \times \mathrm{XOther}_{m} + \varepsilon_{m} \tag{2}$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2009 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times HeatShare_{09}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2009 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	767
Electric Space Heating Heat Pump	127

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models and thereafter, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a 10-year horizon. To introduce price effects, the Heat Index as defined by

Equation 4 above is multiplied by a 10-year moving-average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma} \tag{8}$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{Elec\Pr ice_{y,m}}{Elec\Pr ice_{09,7}}\right)^{\lambda} \times \left(\frac{Gas\Pr ice_{y,m}}{Gas\Pr ice_{09,7}}\right)^{\kappa} \tag{9}$$

Where:

- *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2009
- *HHSize* is average household size in a year (y)
- *Income* is average real income per household in year (y)
- *ElecPrice* is the average real price of electricity in month (m) and year (y)
- *GasPrice* is the average real price of natural gas in month (m) and year (y)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m} \qquad (10)$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \tag{11}$$

Data values in 2009 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times CoolShare_{09}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2009 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,219
Space Cooling Heat Pump	240
Room Air Conditioning	177

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models and thereafter, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \tag{13}$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09}}\right)^{\kappa} \tag{14}$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2009.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \qquad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{09}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \qquad (16)$$

$$(TenYearMovingAverageElectric\Pr ice)^{\lambda} \times (TenYearMovingAverageGas\Pr ice)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.10} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09}}\right)^{\phi} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09}}\right)^{\lambda} \tag{17}$$

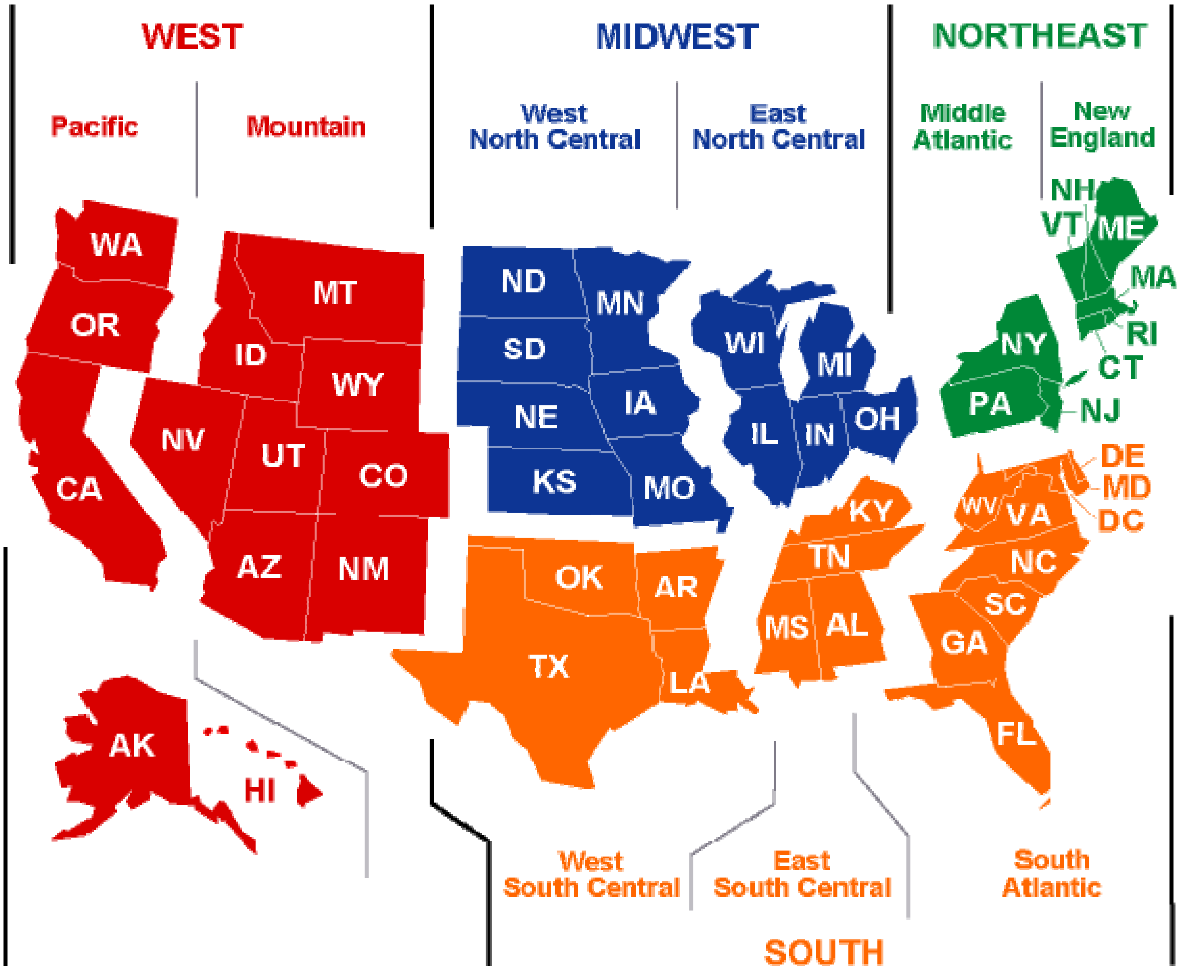
The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{18}$$

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in Figure 18. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 3.

Figure 18: Mapping of States to Census Divisions



Source: http://www.eia.doe.gov/emeu/reps/maps/us_census.html

Table 3: List of SAE Files

Spreadsheet	*MetrixND* Project File
NewEngland.xls	SAE_NewEngland.ndm
MiddleAtlantic.xls	SAE_MiddleAtlantic.ndm
EastNorthCentral.xls	SAE_EastNorthCentral.ndm
WestNorthCentral.xls	SAE_WestNorthCentral.ndm
SouthAtlantic.xls	SAE_SouthAltantic.ndm
EastSouthCentral.xls	SAE_EastSouthCentral.ndm
WestSouthCentral.xls	SAE_WestSouthCentral.ndm
Mountain.xls	SAE_Mountain.ndm
Pacific.xls	SAE_Pacific.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The *MetrixND* project files are linked to the data in these spreadsheets. In these project files, the end-use *Usage* variables are constructed and the SAE model is estimated.

Each of the nine SAE spreadsheets contains the following tabs.

- **Definitions -** Contains equipment, end use, worksheet, and Census Division definitions.
- **Intensities -** Calculates the annual equipment indices.
- **Shares -** Contains historical and forecasted equipment shares. The default forecasted values are provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **Efficiencies -** Contains historical and forecasted equipment efficiency trends. The forecasted values are based on projections provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **StructuralVars -** Contains historical and forecasted square footage, number of households, building shell efficiency index, and calculation of structural variable. The forecasted values are based on projections provided by the EIA.
- **Calibration -** This tab contains calculations of the base year *Intensity* values used to weight the equipment indices.
- **EIAData -** Contains the raw forecasted data provided by the EIA.
- **MonthlyMults -** Contains monthly multipliers that are used to spread the annual equipment indices across the months.
- **EV -** Worksheet for incorporating electric vehicle (EV) impacts.
- **PV -** Worksheet for incorporating photovoltaic battery (PV) impacts.

The *MetrixND* Project files are linked to the *AnnualIndices*, *ShareUEC*, and *MonthlyMults* tabs in the spreadsheets. Sales, economic, price and weather information for the Census Division is provided in the linkless data table *UtilityData*. In this way, utility specific data and the equipment indices are brought into the project file. The *MetrixND* project files contain the objects described below.

Parameter Tables

- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use. There are five types of elasticities included on this table.

  - Economic variable elasticities
  - Short-term own price elasticities
  - Short-term cross price elasticities
  - Long-term own price elasticities

- Long-term cross price elasticities

The short-term price elasticities drive the end-use usage equations. The long-term price elasticities drive the Heat, Cool and other appliance indices. The combined price impact is an aggregation of the short and long-term price elasticities. As such, the long-term price elasticities are input as incremental price impact. That is, the long-term price elasticity is the difference between the overall price impact and the short-term price elasticity.

Data Tables

- **AnnualEquipmentIndices.** This data table is linked to the *AnnualIndices* tab for heating and cooling indices, and *ShareUEC* tab for water heating, lighting, and appliances in the SAE spreadsheet.
- **UtilityData.** This is a linkless data table that contains sales, price, economic and weather data specific to a given Census Division.
- **MonthlyMults.** This data table is linked to the corresponding tab in the SAE spreadsheet.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **ResidentialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.
- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table is used to compute the monthly sales forecasts by end uses.

Models

- **ResModel:** This is the Statistically Adjusted End-Use Model.

Steps to Customize the Files for Your Service Territory

The files that are included in this package contain regional data. If you have more accurate data for your service territory, you are encouraged to tailor the spreadsheets with that information. This section describes the steps needed to customize the files.

Minimum Customization

- Save the *MetrixND* project file and the spreadsheet into the same folder
- Select the spreadsheet and *MetrixND* project file from the appropriate Census Division
- Open the spreadsheet and navigate to the *Calibration* tab
- In cell "B8", replace base year Census Division use-per-customer with observed use-per-customer for your service territory
- Save the spreadsheet and open the *MetrixND* project file
- Click on the *Update All Links* button on the *Menu* bar
- Review the model results

Customizing the End-use Share Paths

In addition to the minimum steps listed above, you can install your own share history and forecasts. To do this, navigate to the *Share* tab in the spreadsheet and paste in the values for your region. Make sure that base year shares on the *Calibration* tab reflect changes on the *Shares* tab.

Customizing the End-use Efficiency Paths

Finally, you can override the end-use efficiency paths that are contained on the *Efficiencies* tab of the spreadsheet.

Appendix A:
Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to identify the end-use factors driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to the SAE approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast, thereby providing a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and efficiency levels, SAE models can explain changes in usage levels and weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2015 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.3 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \quad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \qquad (3)$$

Where

- $XHeat_{y,m}$ is estimated heating energy use in year y and month m,
- $HeatIndex_y$ is the annual index of heating equipment, and
- $HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y / Eff_y \right)}{\left(HeatShare_{04} / Eff_{04} \right)} \tag{4}$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft} \right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}} \right)^{-0.18} \tag{6}$$

Where

- *BDays* is the number of billing days in year *y* and month *m*, these values are normalized by 30.5, which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month
- *HDD* is the annual heating degree days for 2004,
- *Output* is a real commercial output driver in year *y*,

- *Price* is the average real price of electricity in month *m* and year *y*,

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{7}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year *y* and month *m*,
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left(CoolShare_y / Eff_y \right)}{\left(CoolShare_{04} / Eff_{04} \right)} \tag{8}$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e}\right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \tag{10}$$

Where

- *WgtCDD* is the weighted number of cooling degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_{y}^{Type} / Eff_{y}^{Type}}{Share_{04}^{Type} / Eff_{04}^{Type}} \right) \tag{12}$$

Where

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh / Sqft_{e}} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

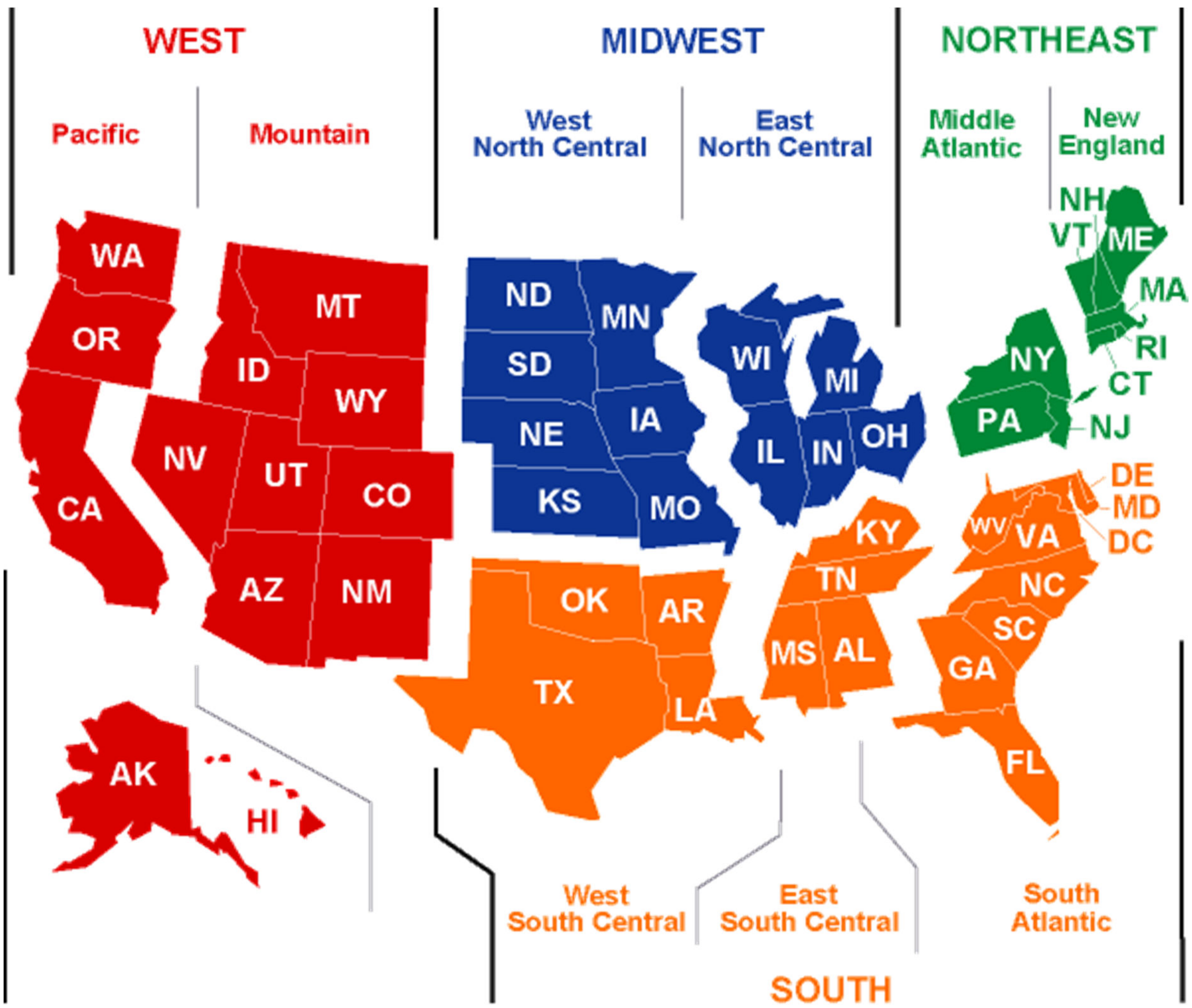
$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}}\right)^{-0.18} \tag{14}$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

1.4 Supporting Spreadsheets and *MetrixND* Project Files

The SAE approach described above has been implemented for each of the nine census divisions. A mapping of states to census divisions is presented in Figure 1. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 1.

Figure 1: Mapping of States to Census Divisions*



*Map Source: http://www.eia.gov/consumption/manufacturing/maps.cfm

Table 1: List of SAE Files

Spreadsheets	*MetrixND* Project Files
NewEnglandCom.xls	NewEnglandCom.ndm
MiddleAtlanticCom.xls	MiddleAtlanticCom.ndm
EastNorthCentralCom.xls	EastNorthCentralCom.ndm
WestNorthCentralCom.xls	WestNorthCentralCom.ndm
SouthAtlanticCom.xls	SouthAltanticCom.ndm
EastSouthCentralCom.xls	EastSouthCentralCom.ndm
WestSouthCentralCom.xls	WestSouthCentralCom.ndm
MountainCom.xls	MountainCom.ndm
PacificCom.xls	PacificCom.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The data from these spreadsheets are linked to the *MetrixND* project files. In these project files, the end-use *Usage* variables (Equations 6, 10, and 14 above) are constructed and the SAE model is estimated.

The nine spreadsheets contain the following tabs.

- **BaseYrInput.** This tab contains base year Census Division intensities by end-use and building type as well as default building type weights. It also contains functionality for changing the weights to reflect utility service territory.
- **Efficiency.** This tab contains historical and forecasted end-use equipment efficiency trends. The forecasted values are based on projections provided by the EIA.
- **Shares.** This tab contains historical and forecasted end-use saturations. The procedure by which these are calculated is explained in the text above.
- **ShareEff.** This tab is used for the calculation of the annual equipment indices.
- **AnnualIndices.** This tab contains the annual *Heat*, *Cool* and *Other* equipment indices.
- **Intensity.** This tab contains the annual intensity (kWh/sqft) projections by end-use.
- **FloorSpace.** This tab contains the annual floor space (sqft) projections by end-use.
- **PV.** This tab is used to incorporate the impact of photovoltaic batteries into the forecast.

The *MetrixND* project files contain the following objects.

Parameter Tables

- **Parameters.** This parameter table includes the values of the annual HDD and CDD in 2004 used to calculate the *Usage* variables for each end-use.
- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use.

Data Tables

- **AnnualIndices.** This data table is linked to the *AnnualIndices* tab in the Commercial SAE spreadsheet and contains sales-adjusted commercial SAE indices.
- **Intensity.** This data table is linked to the *Intensity* tab in the Commercial SAE spreadsheet.
- **FloorSpace.** This data table links to *FloorSpace* tab in the Commercial SAE spreadsheet.
- **UtilityData.** This linkless data table contains Census Division level data. It can be populated with utility-specific data.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the output and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **CommercialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model. Structural variables based on the intensity/floor space combination are also calculated here.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.
- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table breaks the forecast down into its heating, cooling and other components.

Models

- **ComSAE:** The commercial SAE model (energy forecast driven by end-use indices, price, and output projections).
- **ComStruct:** Simple stock model (energy forecast driven by end-use energy intensities, and square footage).

Appendix C – Rate Class to Revenue Class Allocation

Company	*Revenue Class*	*Rate Class*
LG&E	Commercial	Commercial Gas Service (CGS)
		Residential Gas Service (RGS)
		As Available Gas Service (AAGS)
		Industrial Gas Service (IGS)
	Industrial	As Available Gas Service (AAGS)
		TS-2: Gas Trans/Firm Balancing
		Industrial Gas Service (IGS)
	Public Authority	Commercial Gas Service (CGS)
		Residential Gas Service (RGS)
		As Available Gas Service (AAGS)
		Industrial Gas Service (IGS)
	Residential	Residential Gas Service (RGS)
	Gas Transport	As Available Gas Service (AAGS)
		Gas Transport Service
		TS-2: Gas Trans/Firm Balancing
	Intracompany	Gas Special Contracts – LG&E

Annual Natural Gas Sendout Process

LG&E®

Sales Analysis & Forecasting
September 2016

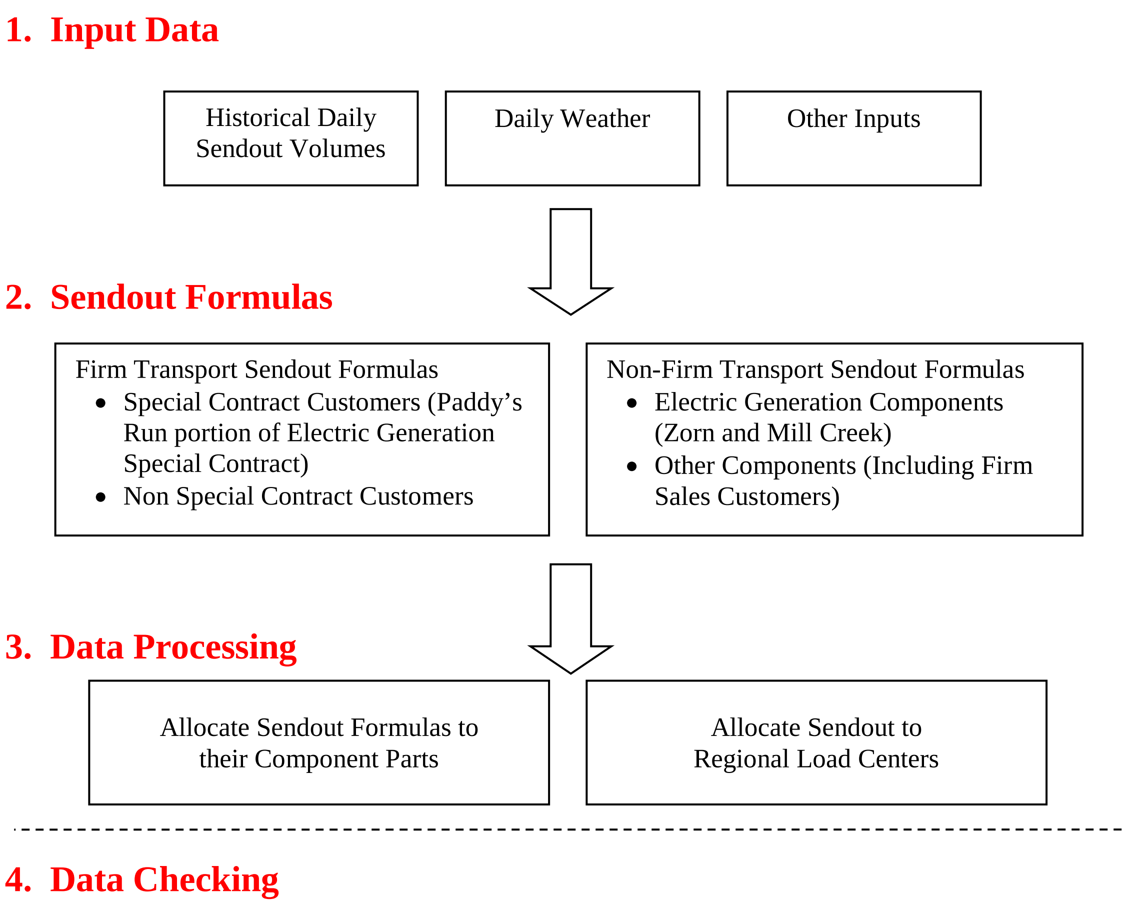
Table of Contents

1 Introduction

The Gas Supply Department forecasts daily sendout (DSO) as a part of its gas supply planning process. Each year, Sales Analysis & Forecasting provides daily sendout formulas to the Gas Supply Department. Like the volume forecast, the production of the sendout formulas can be divided into four parts (see Figure 1). In the first part of the process, input data is gathered and prepared for use in the subsequent parts. The following data items are key inputs to the production of the daily sendout formulas:

- Historical daily gas sendout volumes
- Daily weather data
- Other data including gas used by company-owned facilities and Generation Planning's forecast of gas used by Zorn, Mill Creek and Paddy's Run.

Figure 1 –Sendout Formula Process Diagram



DSO is recorded for the total system and for Firm Transportation (FT) customers. FT customers include special contract customers and non-special contract customers. One of the FT special contract customers is the Paddy's Run portion of the Electric Generation Special Contract. The difference between total DSO and FT sendout is "NonFT" sendout. NonFT sendout includes sales to retail customers, electric generation uses, other company uses, and losses. Electric generation uses include gas used by Zorn and Mill Creek. Since September 2014, Cane Run has been served by Texas Gas and is no longer served by the LG&E Gas Business. In the second part of the process, sendout formulas are produced for NonFT and FT sendout. Then, in the third part of the process, the NonFT and FT sendout formula parameters are allocated to their component parts.

The final part of the process is data checking. Every step in the production of the sendout formulas is checked before proceeding to the next step.

2 Input Data

Table 1 provides a summary of the data inputs used to produce the sendout formulas. The sections to follow describe the key processes used to prepare the data for use in this process.

Table 1 – Data Inputs for Production of DSO Formulas

Data	**Source**	**Format**
Historical DSO Volumes	Gas Supply (Monthly DSO Variance Report)	Daily Volumes (Total Sendout Excluding Gas Used by Electric Generating Stations and FT Sendout)
Historical Daily Average Temperatures	Gas Supply (Monthly DSO Variance Report)	Daily Temperatures
Other Company Uses	Louisville Gas & Electric Company Distribution of MCF Sendout	Monthly Reports
Forecasted Volumes for Zorn, Mill Creek, and Paddy's Run Generation Units	Generation Planning	Monthly
Monthly Normal Weather Forecast	Sales Analysis & Forecasting	Monthly HDD/CDDs
Daily Normal Weather Forecast	Sales Analysis & Forecasting	Daily HDD/CDDs
Design Weather	Gas Supply	Daily HDDs

2.1 Historical DSO Volumes

LG&E delivers natural gas to customers each day by re-delivering natural gas received from interstate pipelines. Additionally, gas may be withdrawn from company-owned storage facilities to meet system requirements. The total amount of gas delivered into the system on a daily basis is the total daily sendout (DSO).

DSO is recorded for the total system and for Firm Transportation (FT) customers. FT customers include special contract customers and non-special contract customers. The FT special contract customer is the Paddy's Run portion of the Electric Generation Special Contract. The difference between the total system DSO and FT sendout is "NonFT" sendout. In addition to sales to retail customers, NonFT sendout includes gas used by company-owned generating assets, other company uses, and losses. Electric generation uses include gas used by Zorn and Mill Creek. Table 2 contains a complete list of the FT and NonFT sendout components.

Table 2 – FT and NonFT Sendout Components

NonFT Sendout	FT Sendout
Company Uses – Zorn	Firm-Transportation (Non Special Contract)
Company Uses – Other	Paddy's Run (Electric Generation Special Contract)
Gas Lost and Unaccounted For	
Firm-Sales	
Mill Creek (Electric Generation Special Contract)	
Distributed Generation	
Residential Gas Service	
Commercial Gas Service	
Industrial Gas Service	
Standby Transportation Sales	
Commercial TS-2	
Industrial TS-2	
As-Available Gas Service Sales	
As-Available Gas Service Transport	

2.2 Historical Daily Weather Data

The historical daily weather series used in the production of the DSO formulas is supplied by the Gas Supply Department and is based on a Gas Day that begins and ends at 10:00 AM (vs. 12:00 AM).

2.3 Daily Normal Weather Forecast

A daily normal weather forecast is used to produce a forecast of DSO under normal weather conditions. The daily normal weather forecast is based on thirty years of historical weather data.

3 Sendout Formulas

The monthly sendout formulas provided to the Gas Supply Department are in the format requested by the Gas Supply Department and include the following parameters.

Table 3 – Sendout Formula Parameters

Parameter	**Description**
BL_{wknd}	Weekend base load usage (Mcf).
BL_{wkdy}	Weekday base load usage (Mcf).
BP_1	1st HDD breakpoint.
BP_2	2nd HDD breakpoint.
BP_3	3rd HDD breakpoint.
BP_4*	4th HDD breakpoint.
T_1	1st temperature coefficient.
T_2	2nd temperature coefficient.
T_3	3rd temperature coefficient.
T_4*	4th temperature coefficient.

*Applicable for the January and February sendout formulas only.

The 4th breakpoint and coefficient were added to the January and February formulas to account for extreme temperatures experienced during 2014. The following equations are used to compute DSO for a given month and usage type. The "max" function returns the largest value in a set of values (e.g., max(20, 0) = 20).

If the current day is a weekend day,

$$DSO = BL_{wknd} + \max(HDD\text{-}BP_1, 0)*T_1 + \max(HDD\text{-}BP_2, 0)*T_2 + \max(HDD\text{-}BP_3, 0)*T_3 + \max(HDD\text{-}BP_4, 0)*T_4$$

Else,

$$DSO = BL_{wkdy} + \max(HDD\text{-}BP_1, 0)*T_1 + \max(HDD\text{-}BP_2, 0)*T_2 + \max(HDD\text{-}BP_3, 0)*T_3 + \max(HDD\text{-}BP_4, 0)*T_4$$

$$HDD = \max(65\text{-Average Gas Day Temperature}, 0)$$

The weekend and weekday base load parameters include gas used for water heating, which is a function of ground water temperatures. As ground water temperatures decrease, the monthly base load parameters would be expected to increase. The HDD breakpoint parameters are points along the DSO line where the slope changes. The temperature coefficients define the slope of the DSO line between breakpoints.

An important decision in the formula specification process is selecting the period of history over which the sendout formulas are specified. The primary objective in making this decision is to select a period of history with a representative set of high and low temperatures. Generally, daily observations from two historical months – approximately 60 daily observations in total – are used to estimate the DSO coefficients for each month. Daily observations from other months are incorporated when temperatures in more recent months are not representative.

The following sections summarize the processes used to specify the NonFT and FT sendout formulas. Formula parameters are ultimately developed for every component of NonFT and FT sendout in Table 2 and every month in the 5-year forecast period.

3.1 DSO Formula Specification

The process used to specify NonFT and FT sendout formula coefficients differs for the winter and summer months.

3.1.1 Winter DSO Formula Specification

For the winter months, SAS and R software was used to optimize the formula coefficients based on historical DSO volumes and historical daily average temperatures. DSO formulas are used in inventory planning. Optimizing formula coefficients is an iterative process with feedback from other groups aimed at minimizing forecast errors, particularly under extreme weather scenarios.

3.1.2 Summer DSO Formula Specification

Since there is little, if any, weather-sensitive load in the summer months, the summer formula coefficients are specified by simply averaging weekday and weekend loads by month.

3.2 Reasonability Checks

Once the summer and winter formulas are specified, the formulas are reviewed to make sure the following criteria are met:

1. The relationships between the weekend and weekday base load parameters in the winter months and the differences between base load parameters from one month to the next should be consistent with history. The latter is somewhat subjective for the winter months due to the lack of historical sendout observations under zero HDD weather conditions. Some insights about these relationships can be obtained by comparing historical weekend and weekday loads by month and HDD.
2. For a winter month, the forecasted usage in the DSO formula should be upward sloping. In theory, the heating response during the winter months should resemble an “S” curve. The heating response is staggered as temperatures initially begin to get cooler. Then, the response becomes consistent as all customers are heating their homes. At some point, however, the heating response begins to taper off as some customers reach their maximum heating capacity.

3.3 Formula Specification Under Design Weather Conditions

Specifying the sendout formulas under design weather conditions with an “ordinary least squares” approach may not be possible due to the lack of recent historical sendout observations under peak design weather conditions. If recent sendout data under peak design weather conditions is not available, an analysis would be conducted using historical sendout data to produce reasonable estimates for peak sendout. The following guidelines were followed when estimating these values:

1. Ideally, the peak estimate for a given month should be based on previous observations in that month under peak weather conditions.
2. More recent observations are better than less recent observations. However, due to special circumstances, some historical observations should not be incorporated in the analysis. For example, the observed sendout on Christmas Eve of 2004 – which was very cold – may not be a good reference point because the day was a holiday.
3. In the absence of comparable historical data for a given month, a reasonable peak estimate may be derived based on historical observations in an adjacent month.

4. In some cases, it may make sense to use the assumed base load usage to compute an implied use-per-HDD value for a historical observation. Then, an estimate of peak sendout can be computed based on the peak HDD value (i.e., peak sendout = base load + use-per-HDD*peak HDD).

Once the peak estimates are determined, the final temperature coefficient may need to be adjusted so that the formula's sendout prediction under peak weather conditions will match the estimate.

4 Data Processing

After the NonFT and FT DSO formulas are specified, the formula parameters are allocated to their component parts and to regional load centers.

4.1 Allocate Sendout Formulas to their Component Parts

The FT sendout formulas are allocated between (a) Paddy's Run's portion of the Electric Generation Special Contract and (b) other FT customers. The formula parameters for Paddy's Run's portion of the Electric Generation Special Contract are based on volume forecasts provided by the Generation Planning group. Consumption at Paddy's Run is assumed to be constant throughout the month (with no variations based on weather or the day of week).

The process used to allocate NonFT sendout to its component parts considers gas used for electric generation, company uses, and losses differently from the other NonFT components. Each of these items is discussed in the following sections.

4.1.1 Gas Used for Electric Generation

A separate set of NonFT sendout formulas is developed for (a) Zorn and (b) Cane Run and Mill Creek. Consumption at each of these generation stations is assumed to be constant throughout the month (with no variations based on weather or the day of week).

4.1.2 Company Uses

Company uses – as a component of the NonFT sendout formula – include compressor station usage, city gate usage, and gas used by company-owned facilities. In the non-winter months, these company uses are only reported on a quarterly basis. Since the gas is actually used throughout the year, the quarterly usage was reallocated to its component months per the guidance of the Gas Control department. This redistribution results in use that is more likely during normal weather.

4.1.3 Gas Lost and Unaccounted For

"Lost and unaccounted for gas" (LAUF) includes fixed gas losses (resulting from leaks on the gas distribution system) and metering losses. Metering losses exist because the gas meters for residential and commercial customers are designed to measure gas at a constant temperature of 60 degrees Fahrenheit. In the winter months – when the temperature is less than 60 degrees and the density of gas is greater – metering losses are positive (i.e., customers actually consume more gas than the meter indicates). In the summer months, metering losses are negative.

The forecast of fixed losses – as the name suggests – is constant at 65,000 Mcf per month or 2,137 Mcf per day. The forecast of LAUF is based on a model developed by the Prime Group ("Prime Model"). This model estimates the temperature of gas – and ultimately the density of gas – for a given month as a function of the current and previous two months temperatures. Then, the model computes the percentage difference between the density of gas at the estimated temperature and the density of gas at 60 degrees.

Metering losses are computed by multiplying the base load and weather-sensitive portions of "net sendout" by this percentage. Net sendout is the gas delivered to customers without temperature-compensating meters. The base load portion of net sendout is computed by subtracting the sum of company uses and fixed losses from the base load portion of NonFT sendout. The weather-sensitive portion of net sendout is equal to the weather-sensitive portion of NonFT sendout.

4.1.4 Other NonFT Components

NonFT sendout (like FT sendout) is comprised of base load and weather-sensitive volumes. Gas used for electric generation, company uses, fixed losses, and the base load portion of metering losses make up a portion of the NonFT base load volumes. The weather-sensitive portion of metering losses makes up a portion of the NonFT weather-sensitive volumes. The remaining portions of the NonFT base load and weather-sensitive volumes must be allocated to the sales components of sendout (RGS, CGS, IGS, AAGS, Commercial TS-2, and Industrial TS-2 sales). To complete this process, the volume forecast for each sales class and month is broken into base load and weather-sensitive sales components. These components provide the basis for allocating the NonFT formula parameters to their component parts and are derived based on class-specific assumptions regarding the class's sensitivity to ground water temperatures and ambient air temperatures. The Distributed Generation (DGGS) component of NonFT is based on contracted volumes.

4.2 Regional Load Center Allocation

NonFT and FT sendout formula parameters are also allocated to two regional load centers: East and West. Each regional spreadsheet has the flexibility to define months by season (winter or summer) and to allow a change in the allocation percent by season.

5 Data Checking

The production of the sendout formula parameters involves a large amount of data and calculations. For this reason, every aspect of the process must be checked for errors. The criteria for checking the key aspects of the process have been discussed in each section of this report.

LG&E KU

PPL companies

2017 Business Plan
Gas Volume Forecast

July 11, 2016

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Sinclair

Forecast Summary

- Economy: Louisville economic indicators remain positive and growth in the Commonwealth as a whole is expected to stay close to 2 percent.
  - *Louisville MSA real gross metro product is expected to increase at 2.6 percent during the second half of 2016 and 2017 according to IHS.*
  - *Louisville MSA unemployment has remained consistent at close to 4.5 percent since early 2015*
  - *Louisville MSA private single-family housing starts are up 15 percent on a rolling 12-month basis.*

- 3% decrease in sales forecast compared to 2016 Plan driven by Residential and Industrial.
- Residential customer forecast higher than 2016 Plan but still with growth of 0.2%. Commercial customers largely consistent with 2016 Plan.
- Major Accounts: 2.5 % decrease in the Major Account forecast compared to 2016 Plan driven by American Synthetic and Ford.

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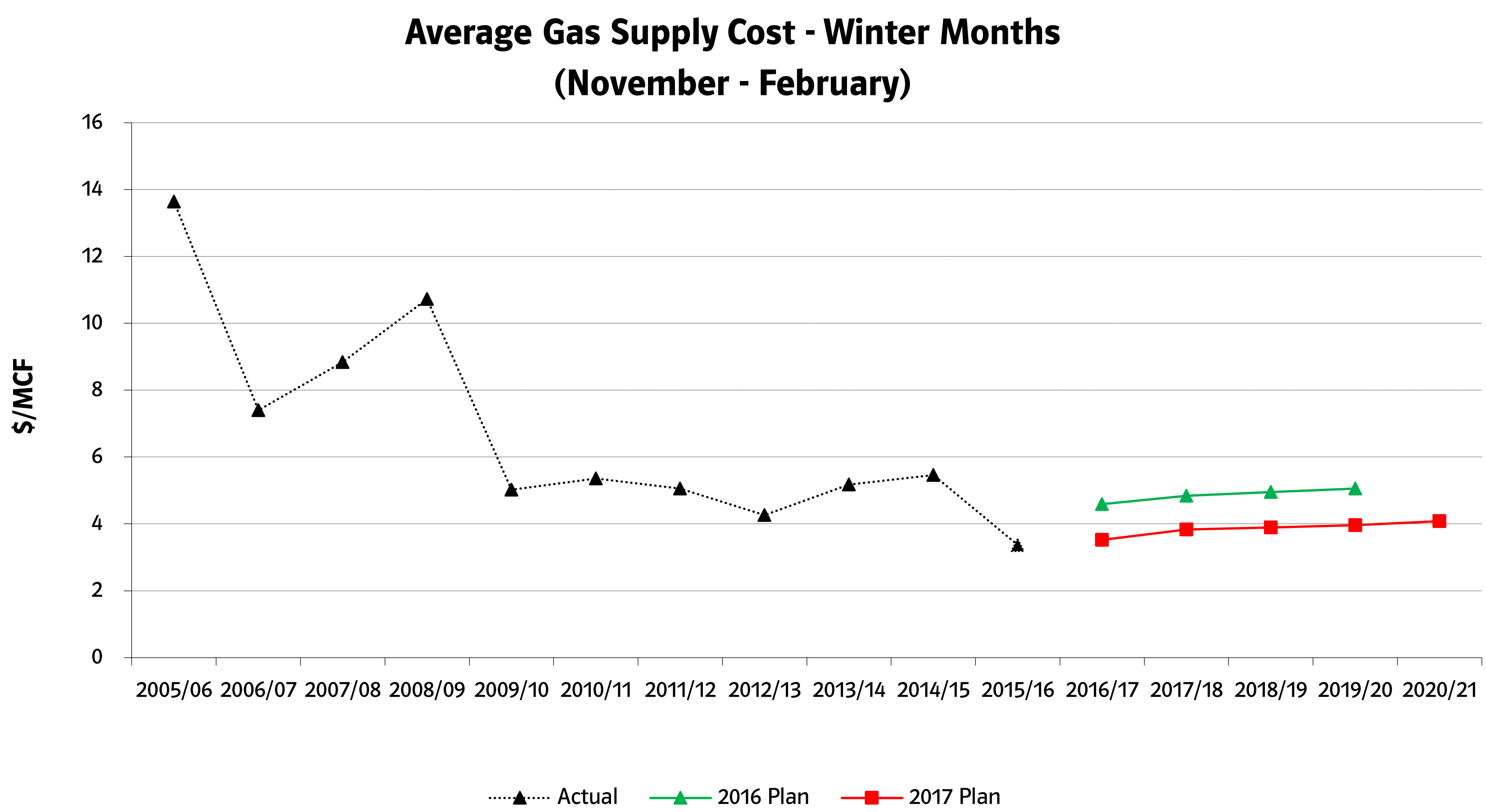
PPL companies

Gas supply cost for winters expected to be lower over the plan period



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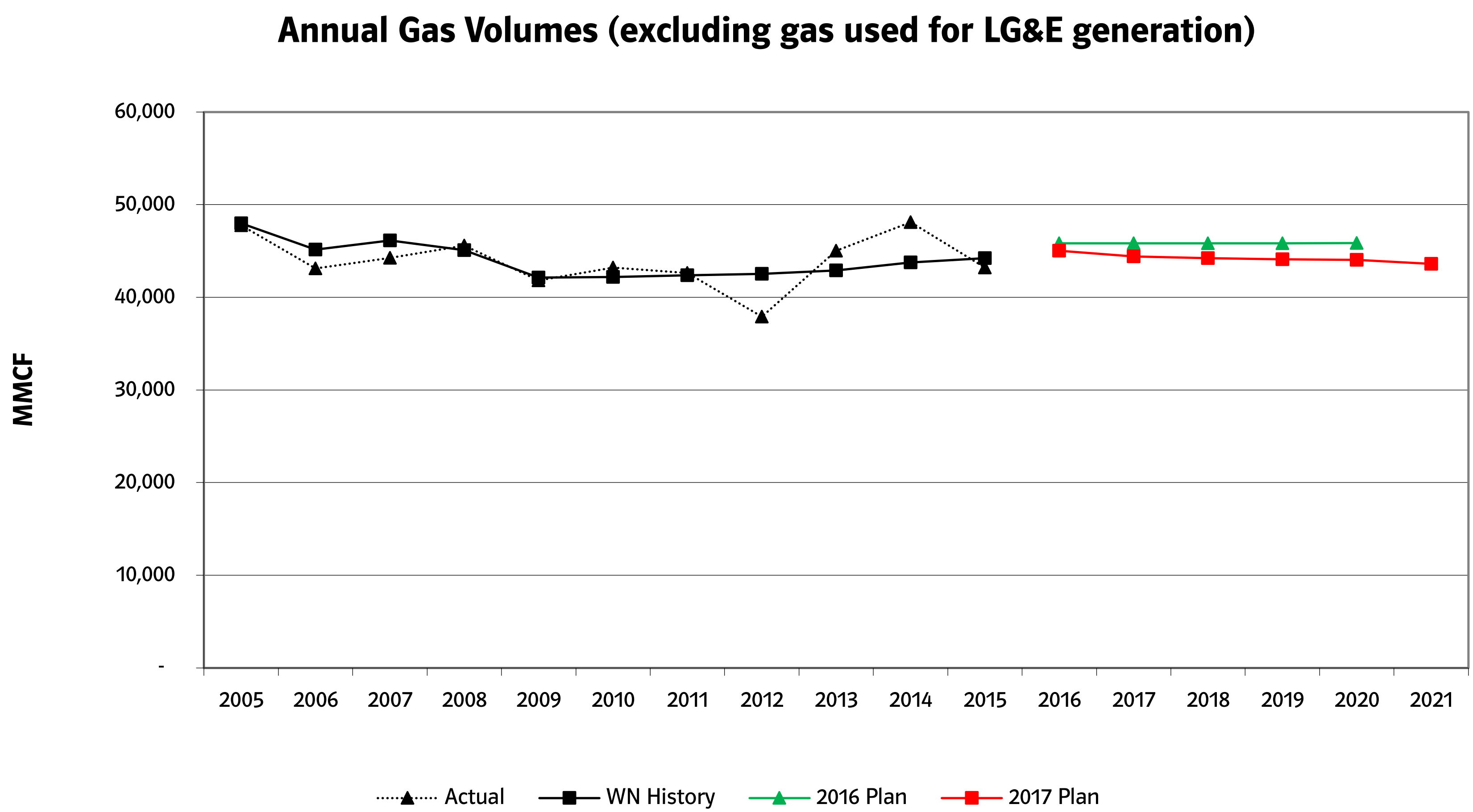
Residential and Industrial decline push the 2017 plan downward relative to 2016 plan



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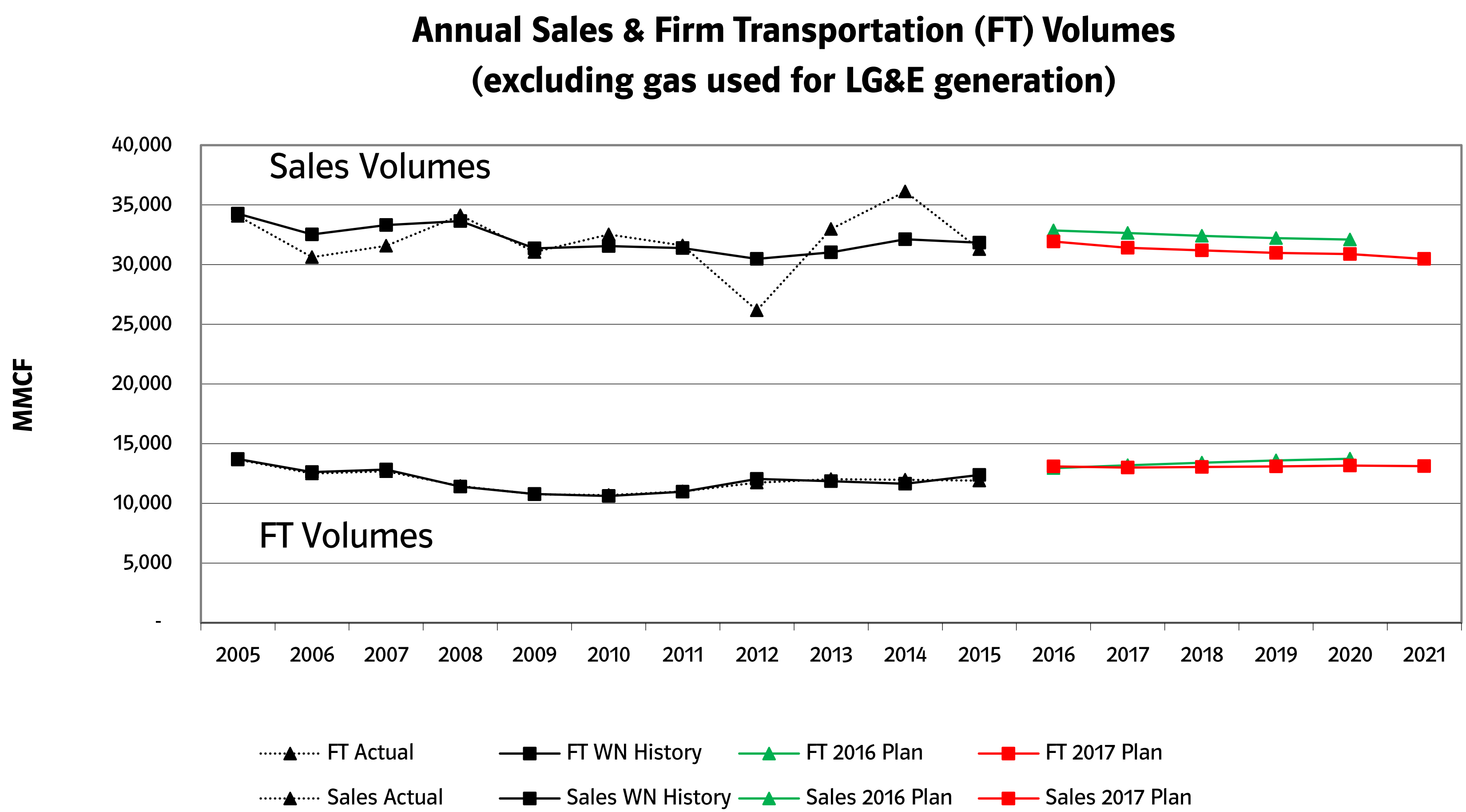
Sales and Transportation volumes are forecasted to be slightly lower long-term than 2016 Plan



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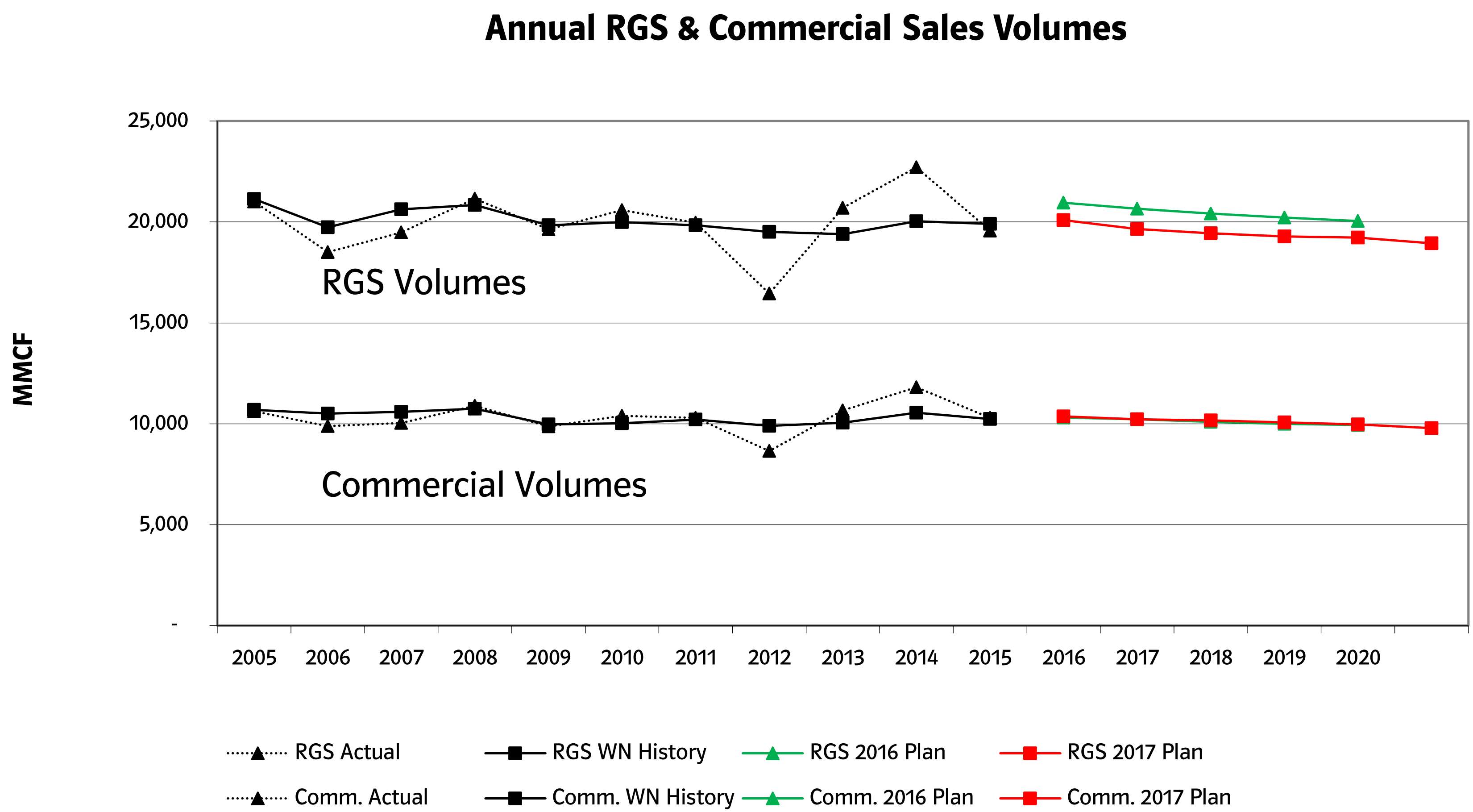
RGS annual volumes forecasted to be lower than 2016 Plan in 2016 and 2017; Commercial the same plan-over-plan



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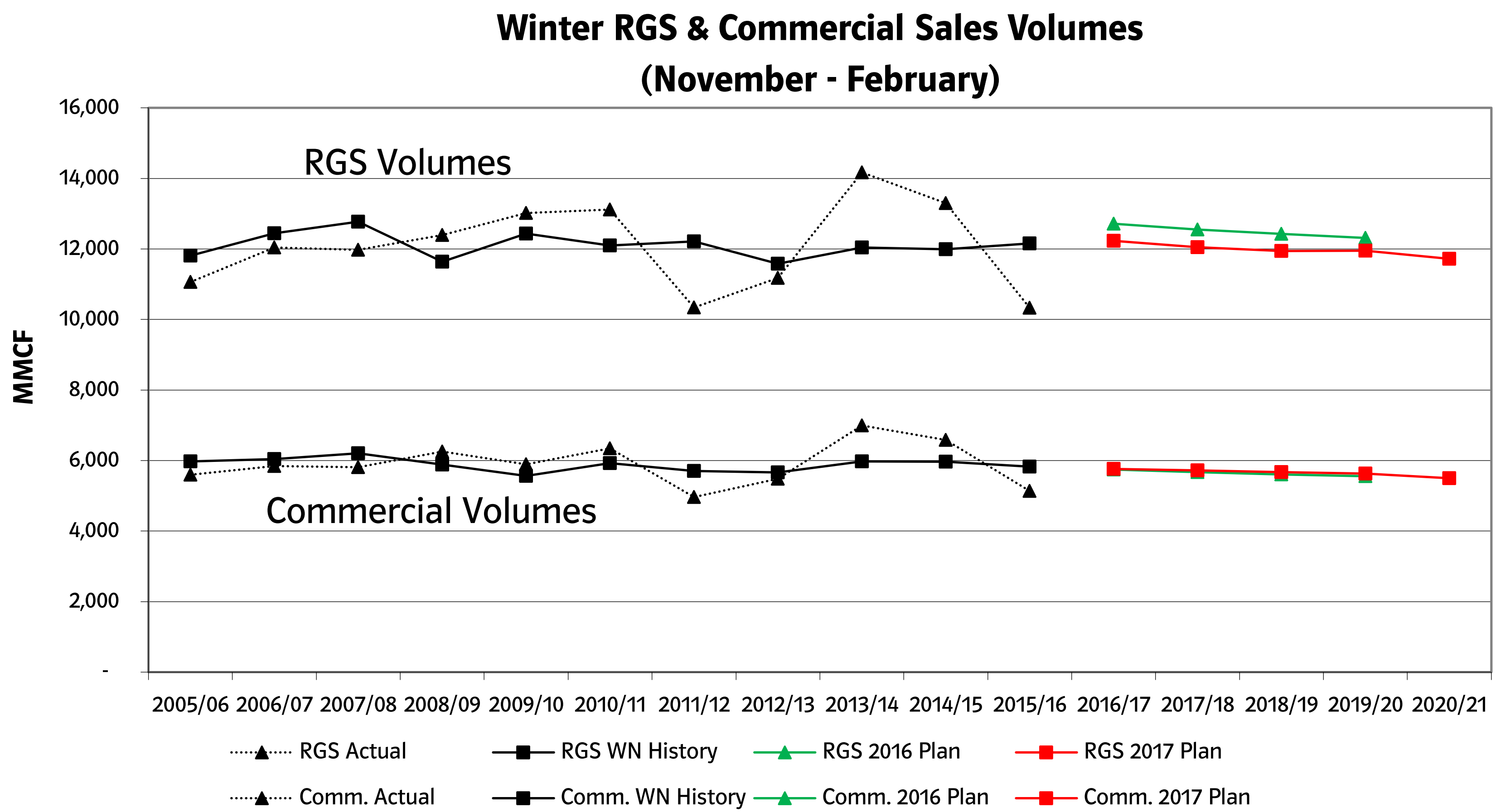
PPL companies

Compared to the 2016 Plan, RGS volumes are slightly lower in the next few winters



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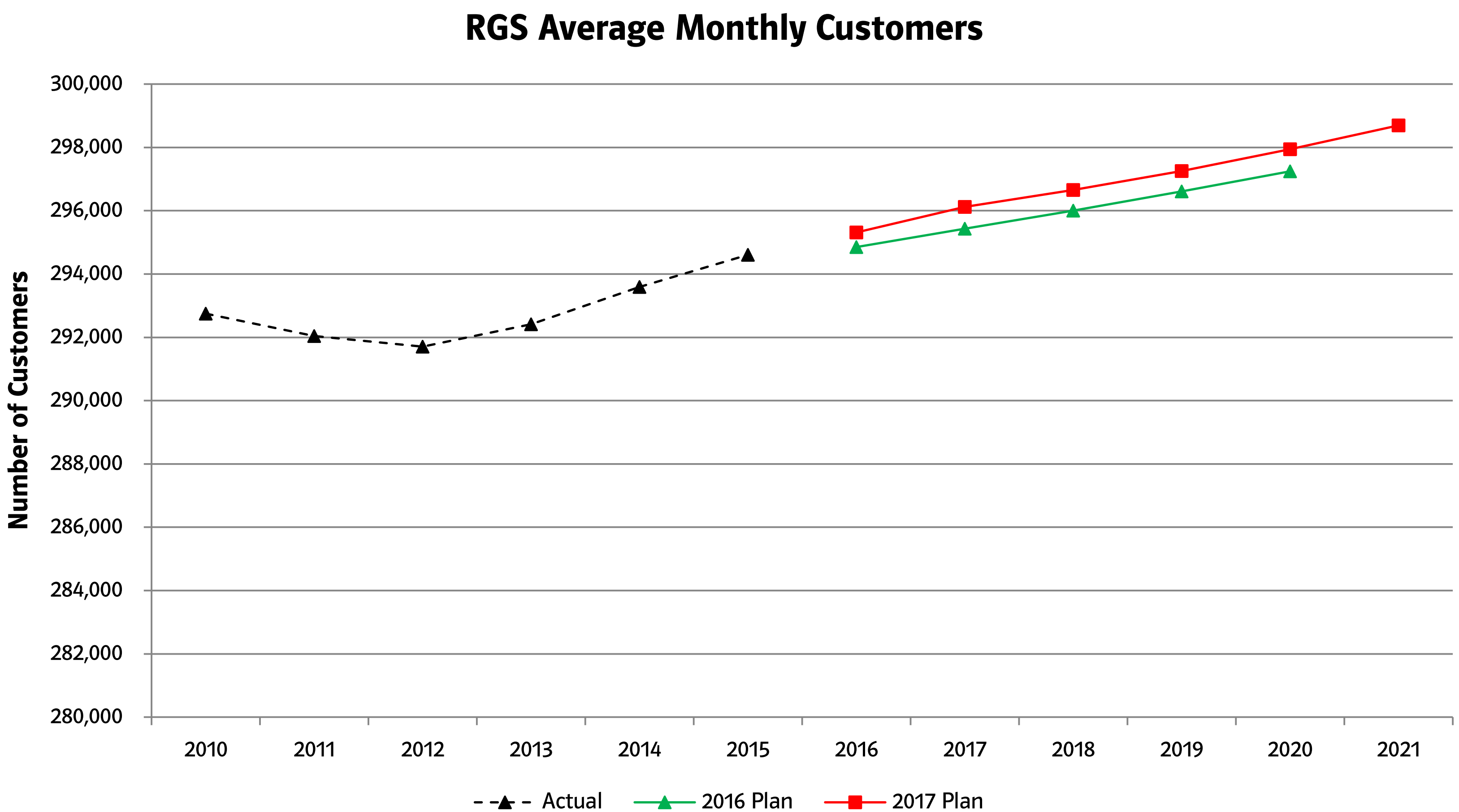
LG&E KU
PPL companies

RGS Customer forecast higher than 2016 Plan



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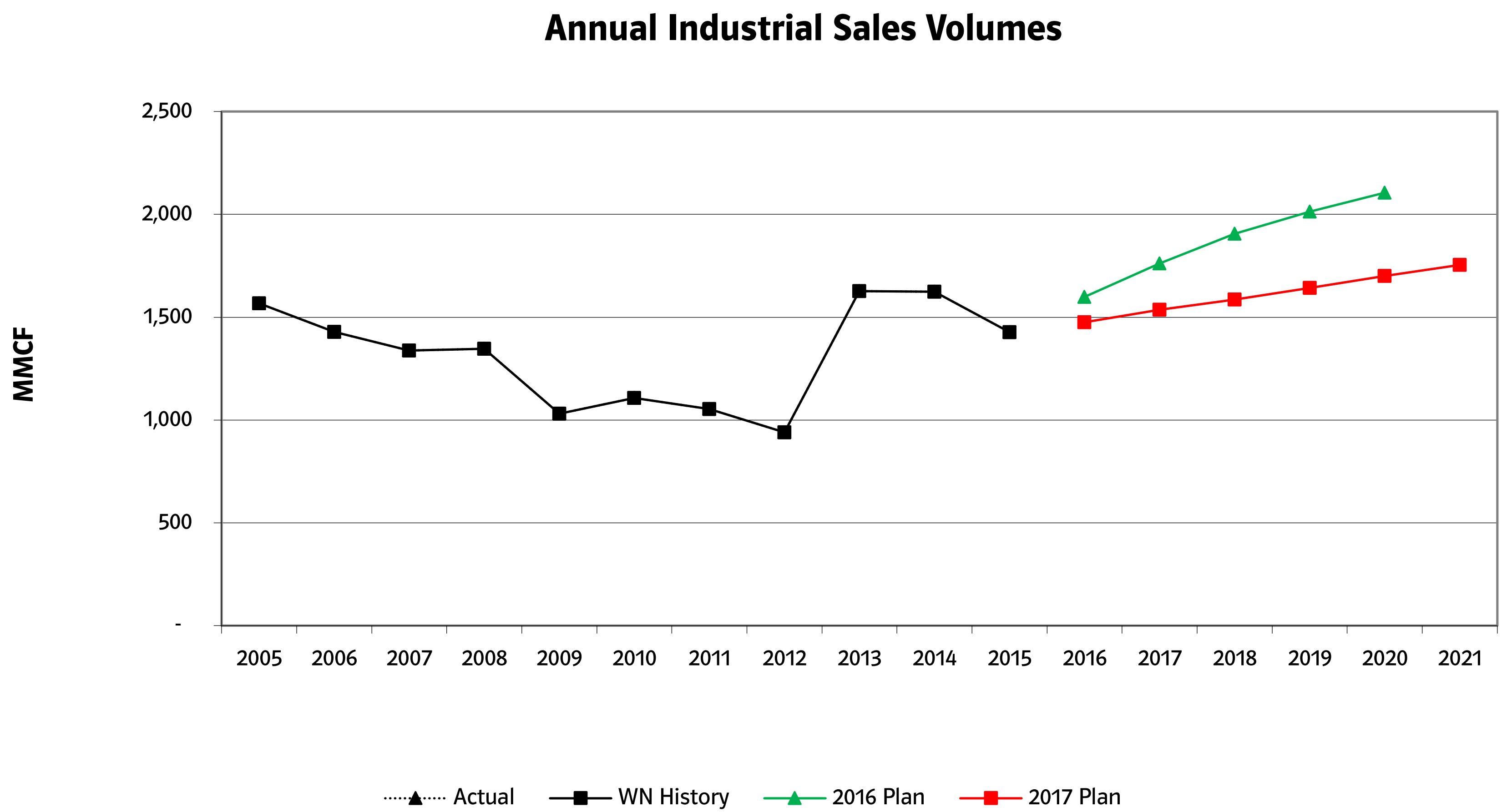
PPL companies

Industrial sales decrease plan-over-plan



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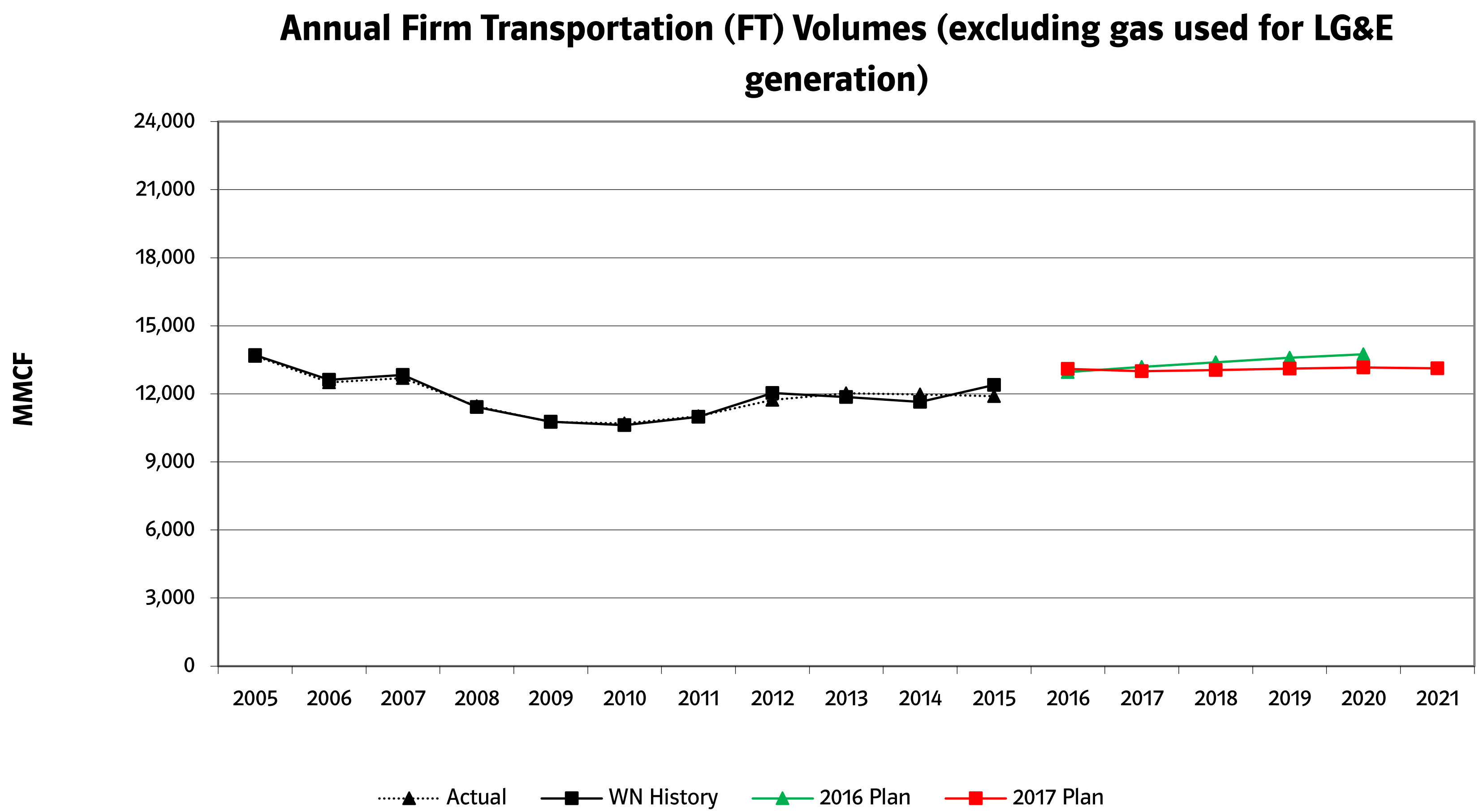
Firm Transportation (FT) volumes flat over the next 5 years



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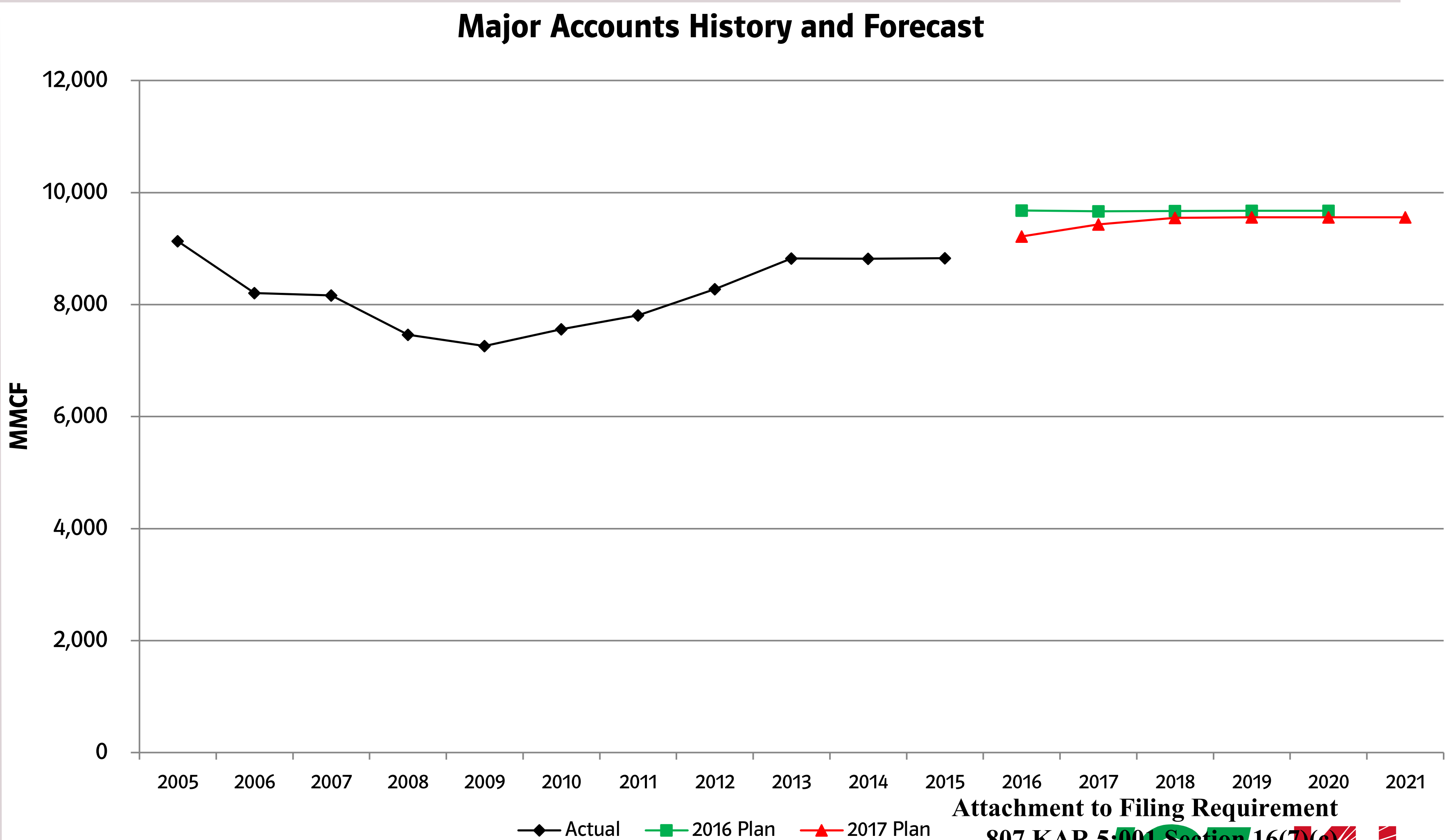
2017 Plan lower in 2016 from slower gain in use by Ford and Lubrizol



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LG&E KU
PPL companies

Large Customer Highlights

- *Jim Beam volume in 2017 is expected to be 94% (318,000 MCF) higher than the 2017 BP as a result of production boom putting their use close to infrastructure constraints*
- *Maker's Mark added capacity and increased production in late 2015 expected to continue . Volume for 2017 is expected to be 42% (95,000 MCF) higher than the 2016 BP*
- *American Synthetic expected to be 52% (390,500 MCF) lower than the 2016 BP from less energy intensive processes due to changing chemical formulas*
- *Reynolds Foil expected to be 79% (108,000 MCF) higher than the 2016 BP as gas use has reverted to levels prior to investments on their electric side*
- *JBS Swift, Baptist Healthcare, Carriage House, and Zeochem are now individually forecasted*
- *BASF and Sypris no longer individually forecasted as their gas use is no longer among the highest users*

PPL companies

Appendix

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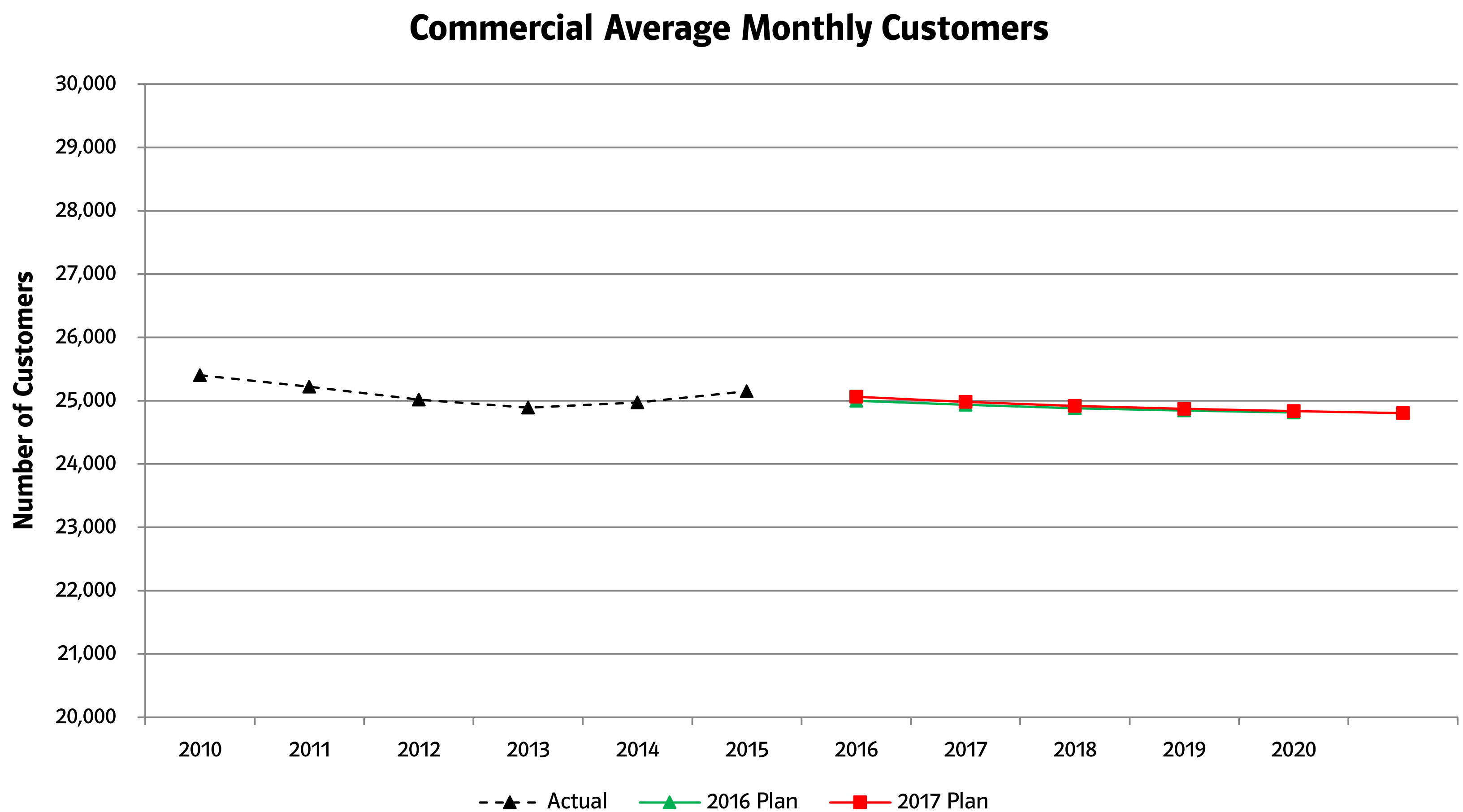
Commercial Customer forecast consistent with 2016 plan



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PPL companies

Annual Generation Forecast Process

PPL companies

Generation Planning & Analysis
2016

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1 Introduction

The Generation Planning group prepares an annual generation and off-system sales ("OSS") forecast for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). This forecast provides the basis for – among other things – the Companies' forecasts of fuel costs, generation-related variable operating and maintenance costs, economy purchased power, and OSS margin. This document summarizes the process used to prepare the generation forecast.

2 Production Cost Model

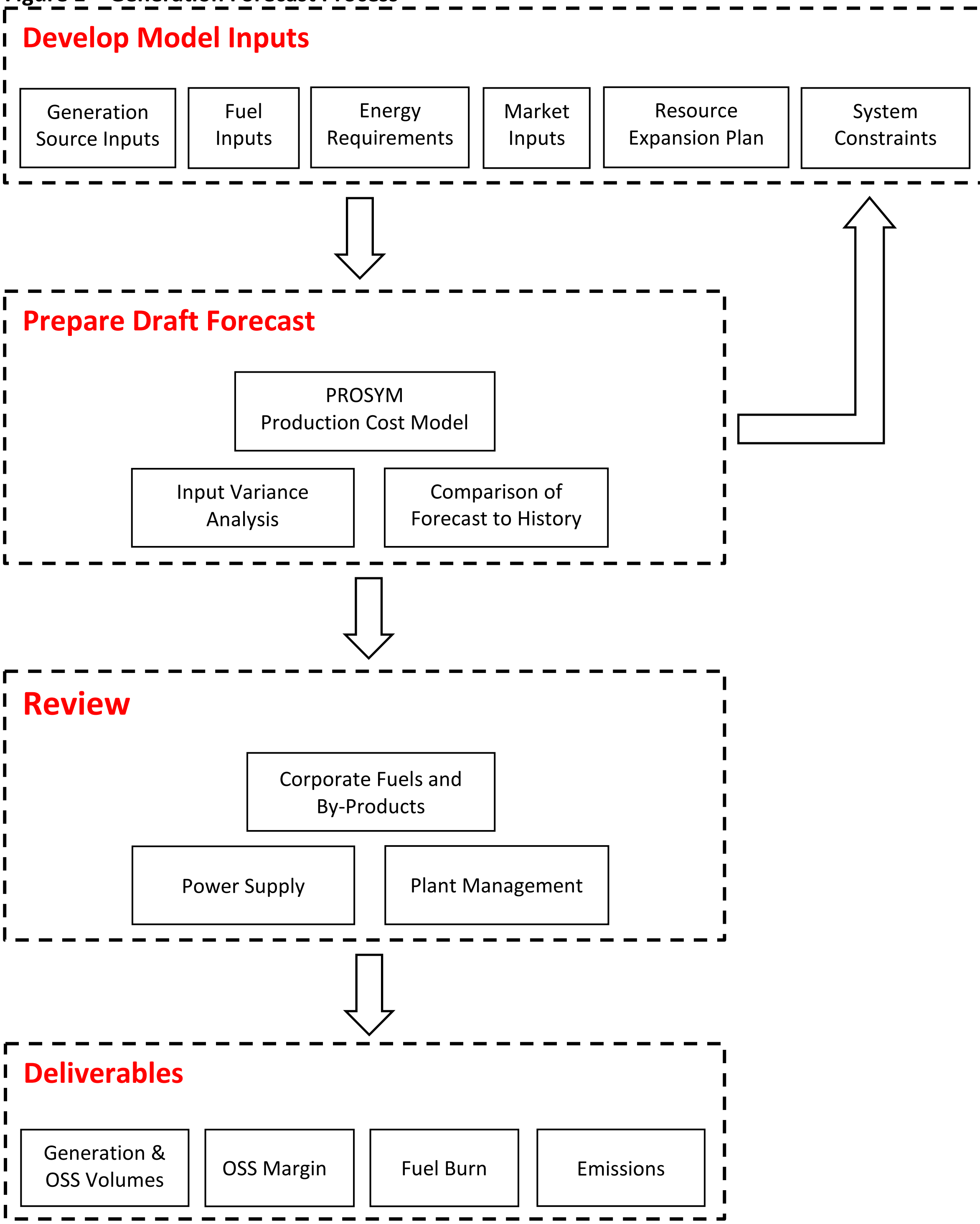
The Companies' generation forecast is developed using ABB's PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve requirements and other aspects of the electric system. PROSYM is a proven production cost model that has been used by utilities throughout the United States for decades.

In addition to PROSYM, SAS, Microsoft Access, and Microsoft Excel are used to process and analyze forecast results. Presentations containing forecast assumptions and results are prepared using Microsoft PowerPoint.

3 Process Overview

Figure 1 provides an overview of the process used to develop the Companies' generation forecast. In the first part of the process, model inputs are developed. Then, the model inputs are loaded into PROSYM and a draft generation forecast is prepared. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded into the model and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. If the forecast results are not deemed reasonable, the applicable model inputs are adjusted and the process is repeated. In the third part of the process, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives. After all parties are satisfied with the results, the generation forecast is finalized and distributed to the groups who use the forecast to prepare financial budgets. Each part of this process is discussed further in the following sections.

Figure 1 – Generation Forecast Process



3.1 Develop Model Inputs

The first part of the process used to develop the Companies' generation forecast involves developing and vetting model inputs. Well-vetted inputs are essential to a good forecast. Wherever possible (and applicable), model inputs are initially developed based on an analysis of historical data. Then, these inputs are reviewed with plant management for reasonableness. Model inputs are adjusted when historical trends are not expected to continue in the future. Table 1 lists the six main categories of model inputs along with the inputs in each category. Each of these categories is discussed further in the following sections.

Table 1 - Key Inputs to the Generation Forecast

Input Category	**Inputs**
Generation Source Inputs	Minimum and maximum capacity, heat rate, emission rates, variable operating and maintenance cost, operating limits, unit availability, company allocation
Fuel Inputs	Coal prices, natural gas prices, oil prices, other fuel-related inputs
Energy Requirements	Hourly energy requirements
Market Inputs	Electricity prices, emission allowance prices, off-system sales and purchase limits, off-system sales and purchase price thresholds
Expansion Plan Inputs	Timing and type of expansion plan units
System Constraints	Transmission constraints, spinning reserve requirements, off-system sales constraints, dispatch order rules

3.1.1 Generation Source Inputs

The generation sources modeled in PROSYM include the Companies' existing sources of generation as well as future generation sources planned to meet customers' growing demand for energy. Generation sources include generating units owned by the Companies, power purchase agreements with other power producers, and the capacity associated with the Companies' curtailable service rider ("CSR") customers.

Generation source inputs define the operating characteristics of the generation sources. These inputs include the source's minimum and maximum capacity, heat rate, emission rates, variable operating and maintenance cost, operating limits, equivalent forced outage rate, and ownership ratio. Each of these inputs is discussed further in the following sections.

3.1.1.1 Minimum and Maximum Capacity

The minimum and maximum capacity (or output) is specified for each generation source as a megawatt ("MW") value for the summer, winter, fall, and spring seasons. Capacity inputs are specified based on an analysis of historical data and unit rating tests but rarely change materially from forecast to forecast.

3.1.1.2 Heat Rate

The heat rate specifies the amount of fuel required to produce a megawatt-hour ("MWh") of electricity. Where applicable, a heat rate curve is specified for each generation source for the summer, winter, fall, and spring seasons. The heat rate curves are specified based on an analysis of historical data and heat rate tests performed by the plants.

3.1.1.3 Emission Rates

Where applicable, PROSYM models the emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), mercury ("Hg"), and carbon dioxide ("CO_2") for each generation source:

- SO_2 Emissions: For coal units, SO_2 emissions are modeled as a function of the unit's SO_2 removal rate and the sulfur content of the fuel. The SO_2 removal rate for each coal unit ranges between

90% and 99%, depending on the vintage of the unit's flue-gas desulfurization ("FGD") equipment.[1] The SO_2 removal rate is specified based on an analysis of historical data and updated in the forecast period for units being retrofitted with new or upgraded FGD equipment. The sulfur content of the fuel is provided by the Corporate Fuels and By-Products group. For gas units, SO_2 emissions are modeled as a function of an average SO_2 emission rate (specified in lb/MMBtu). The SO_2 emission rate for gas units is estimated by the unit manufacturer.

- NO_x Emissions: For coal units, NO_x emissions are modeled as a function of a NO_x emission curve (specified in lb/MMBtu). NO_x emissions vary with the unit's output and are lower for units retrofitted with selective catalytic reduction ("SCR") equipment. The NO_x emission curve is specified based on an analysis of historical data in conjunction with performance expectations associated with the timing of catalyst replacement. For gas units, NO_x emissions are modeled as a function of an average emission rate (also specified in lb/MMBtu) estimated by the unit manufacturer.
- Hg Emissions: For coal units, Hg emissions are modeled as a function of the unit's average Hg emission rate (specified in lb/MMBtu). Average Hg emission rates are based on engineering estimates and vary depending on whether the unit is retrofitted with a fabric filter baghouse or sorbent injection controls.
- CO_2 Emissions: CO_2 emissions are modeled as a function of the unit's average CO_2 emission rate (specified in lb/MMBtu). Average CO_2 emission rates are dependent on the type of fuel burned in the unit and are based on engineering estimates.

3.1.1.4 Variable Operating and Maintenance Cost

Variable operating and maintenance ("O&M") costs include all non-fuel costs that are incurred when operating the generation source. For coal units, variable O&M includes the cost of operating environmental controls. For Cane Run 7, variable O&M includes the cost of its long-term program contract ("LTPC"), which is paid quarterly based on the number of starts and operating hours for the unit. The Companies do not have similar LTPCs in place for their simple-cycle combustion turbines ("SCCTs"); the cost of major maintenance is considered in unit commitment and dispatch decisions but is not modeled as a component of production costs.

3.1.1.5 Operating Limits

The following operating limits are modeled in PROYSM for each generation source. Each of these inputs is specified based on an analysis of historical data.

- Minimum Down-Time: Minimum down-time is the minimum number of hours after coming offline that a generation source must remain offline before it can be brought back online.
- Minimum Up-Time: Minimum up-time is the minimum number of hours after coming online that a generation source must remain on-line before it can be taken offline for economic reasons.
- Ramp-Up Rate: Ramp-up rate is the rate (specified in MW/hour) at which a generation source can increase its output.
- Ramp-Down Rate: Ramp-down rate is the rate (specified in MW/hour) at which a generation source can decrease its output.

3.1.1.6 Unit Availability

The following unit availability inputs are modeled in PROSYM for each source. These inputs determine the extent a source is available for operation.

[1] Brown Units 1-3 share the same FGD.

- Planned Maintenance Schedule: The planned maintenance schedule specifies the timing and duration of planned maintenance events. The schedule is developed with input from plant management, Generation Dispatch, and Project Engineering, such that the outages will have the least economic and reliability impact to customers.
- Equivalent Unplanned Outage Rate ("EUOR"): EUOR inputs determine the amount of time the generation source is unavailable due either to a forced outage or maintenance outage. EUOR inputs are specified based on an analysis of historical data.

3.1.1.7 Company Allocation

The energy and capacity for all generation sources modeled in PROSYM are either wholly or jointly allocated to LG&E and/or KU. For each generation source, the Companies' allocation is specified in PROSYM to facilitate the process of creating generation and other forecasts by company as well as forecasting the After-the-Fact Billing process used to calculate the Fuel Adjustment Clause.

3.1.2 Fuel Inputs

Each thermal generation source is associated with one or more fuel forecasts for startup and for online operation. The fuel inputs in PROSYM specify the cost of fuel, the fuel's heat content, the quantity of fuel required for startup, and – for generation sources where the fuel price is a blend of multiple fuel forecasts – the blend ratio of each fuel forecast. For coal, the fuel inputs also include the fuel's SO_2 content.

3.1.2.1 Coal Prices

A forecast of delivered coal prices is developed for each station by the Corporate Fuels and By-products group. These forecasts reflect the cost of the Companies' contracted coal volumes, the assumed cost of coal that will be contracted in the future, and the cost of transporting fuel from mines to the stations. Based on the coal burn forecast by unit, the Corporate Fuels and By-Products group calculates the target coal purchase tonnage needed each year to maintain desired inventory levels while meeting the forecasted coal burn. The forecasted price per MMBtu for each coal type is the result of computing the weighted average of coal already under contract and the market price of coal. In the first year of the forecast, the market price is the average of coal bids received, but not under contract. In subsequent years, the market price is the weighted average of coal bids received and the forecast from an independent third party consultant, Wood Mackenzie. Beyond the 5th year, prices are increased at the yearly growth rate reflected in the Energy Information Administration's latest Annual Energy Outlook for "All Coals, Minemouth" nominal price forecast.

3.1.2.2 Natural Gas Prices

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas. The initial years of the Henry Hub price forecast reflect monthly forward market prices from NYMEX as of a specific recent quote date, which reflects a current view of forward prices at the time the forecast is prepared. In the subsequent years, the market prices are blended with the EIA's price forecast published in its most recent Annual Energy Outlook. The Henry Hub forward market prices are then adjusted to local delivered prices to KU and LG&E units using an average annual loss factor and a variable O&M charge per MMBtu that also adjusts for average assumed basis differentials. For each station that uses natural gas for startup or online operations, a forecast of delivered natural gas prices is developed by adding transportation costs and a cost for pipeline losses to the forecast of Henry Hub prices.

3.1.2.3 Oil Prices

A forecast of delivered oil prices is developed for coal units that use fuel oil for startup and for SCCTs that can use fuel oil for online operation as an alternative to natural gas. The fuel oil price forecast consists of market prices in the short term that are then interpolated to a long-term forecast. The Companies' delivered price forecast first uses NYMEX New York Harbor #2 fuel oil monthly contract settled prices as far out in time as there is some market liquidity.

Long-term #2 fuel oil prices are developed by applying the historical relationship between New York Harbor #2 fuel oil and West Texas Intermediate ("WTI") oil prices to forecasted WTI prices derived from IHS Global Insight's latest 30-year macro forecast. To integrate the two forecast periods, the short-term market-based fuel oil price forecast is interpolated to the long-term regression-based price forecast. The forecasted #2 fuel oil prices are then multiplied by the average ratio of the Companies' fuel purchase price to the New York Harbor #2 fuel oil price to arrive at the Companies' delivered fuel oil purchase price forecast.

3.1.2.4 Other Fuel-Related Inputs

Other fuel inputs include the fuel blend ratio, the quantity of startup fuel, the fuel's heat content, and fuel's SO_2 content.

- Fuel Blend Ratio – Trimble County 2 burns a blend of Illinois Basin coal and Powder River Basin coals. Since the prices of these coals are specified in separate forecasts in PROSYM, the fuel blend ratio determines the weighting that is used to compute the price of coal for Trimble County 2.
- Quantity of Startup Fuel – For each generating unit, the startup fuel quantity is the amount of fuel required to start the unit. These inputs are specified based on an analysis of historical data with input from plant management.
- Heat Content and SO_2 Content – Fuel heat and SO_2 contents are provided by the Corporate Fuels and By-products group.

3.1.3 Energy Requirements

PROSYM simulates the dispatch of the Companies' generating units to meet hourly energy requirements. The forecast of hourly energy requirements, which consists of native load sales and transmission and distribution losses, is developed by the Sales Analysis and Forecasting group. See the Annual Electric Sales & Demand Forecast Process document for a discussion of the process used to develop the Companies' forecast of hourly energy requirements.

3.1.4 Market Inputs

Market inputs define the market in which the Companies operate. These inputs include spot hourly wholesale electricity prices, emission allowance prices, hourly OSS and economy purchase limits, and OSS and economy purchase price threshold values. Together, these inputs determine when the model should make economy purchases or OSS. Each of the market inputs is discussed in the following sections.

3.1.4.1 Electricity Prices

A forecast of spot hourly electricity prices is developed to model the Companies' interactions with the electricity market. The Companies buy and sell electricity primarily with PJM through the PJM-South Import ("PJM-SI") interface / pricing point which is used in the planning process to represent the electricity market.[2] In the initial years, monthly forward market prices for PJM West Hub ("PJM-WH")[3] quoted by Intercontinental Exchange as of a specific recent quote date are used as a basis for developing an hourly forecast of PJM-SI prices, reflecting the most current view of forward prices at the time the forecast was prepared.[4] In the subsequent years, the market prices are interpolated to a long-term PJM-WH forecast developed using EPIS's AuroraXMP software, a proprietary electricity market model. Monthly PJM-SI prices are derived by applying seasonal discount factors by peak type to the PJM-WH prices. The discount factors are based on historical ratios between actual PJM-SI and PJM-WH prices.

Monthly average PJM-SI prices are shaped to daily average prices by peak type by maintaining a correlation between the Companies' forecasted daily average energy and the forecasted daily average electricity price in each month. This relationship serves as a proxy for the correlation between the daily load level in the PJM market and the corresponding daily average electricity price. The daily average prices are derived by multiplying the forecasted monthly average prices (by peak type) by a daily weighting that reflects the correlated variances between forecasted daily vs. average monthly loads and forecasted daily vs. average electricity prices, based on historical observations. Hourly prices are then derived by multiplying the daily prices by hourly price multipliers that reflect the historical average ratio of hourly prices to daily prices by month and by peak type.

3.1.4.2 Emission Allowance Prices

The dispatch cost for each unit includes the unit's fuel cost, variable O&M costs, and the cost of emission allowances. Emission allowance price forecasts are developed for SO_2, seasonal NO_x, and annual NO_x emissions allowances. Initial prices reflect market prices as of a specific recent quote date for allowances under the Cross-State Air Pollution Rule. Longer-term prices reflect those in IHS Energy's long-term planning scenario. No CO_2 emission allowance price assumptions are made for the Clean Power Plan because of the uncertainty regarding its legal standing and state-level implementation.

3.1.4.3 Hourly Off-System Sales and Purchase Limits

The OSS and purchase limit inputs determine the maximum quantity (in MW) of OSS and economy purchases that can be made in any given hour. Since the volatility of available transmission capacity cannot be modeled in PROSYM, limits on hourly OSS and economy purchases are used to align the volume of modeled OSS and economy purchase transactions with recent historical experience. OSS and economy purchase limits are developed to coincide with the 95th percentile of the distribution of historical hourly OSS and economy purchase volumes.

3.1.4.4 Off-System Sales and Purchase Price Thresholds

When making an OSS or economy purchase, the Companies incur various costs related to the transaction. These costs are referred to as OSS and purchase "thresholds." OSS and purchase thresholds include the cost of transmission and transmission losses, independent system operator

[2] The Companies also transact electricity with counterparties other than PJM. The Companies model PJM as a representative market, considering liquidity and availability of market data.
[3] The PJM market is used as a proxy for all markets available to the Companies because most of the Companies' off-system sales and purchases are expected to be transacted with the PJM market.
[4] The quoted "off-peak wrap" forward prices for PJM-WH are split into off-peak (7x8) and weekend (2x16) peak types using historical ratios.

balancing charges, and a risk premium the Companies' Power Supply group uses to manage the uncertainty that exists between real-time prices and aggregated hourly (or settled) prices.

3.1.5 Resource Expansion Plan Inputs

The expansion plan inputs specify the timing and type of generation sources planned to be added to the Companies' generation portfolio to meet customers' growing need for energy and capacity. These generation sources can take the form of new generating units or power purchase agreements with a third-party provider. Generation source inputs are discussed in Section 3.1.1.

3.1.6 System Constraints

PROSYM enables the user to model a variety of physical constraints that exist within the Companies' transmission system and generation portfolio. These constraints are discussed in the following sections.

3.1.6.1 Transmission Constraints

The Companies' transmission and distribution system is designed to deliver electricity from generation sources to load under a variety of circumstances. Despite the flexibility that is afforded the Companies, some constraints can occur in real time. For example, at least one generating unit at the Brown Station must be operating in moderate to high load scenarios to support adequate voltage in the Lexington area. Furthermore, there are limits to the energy that can flow between LG&E and KU. PROSYM models these and other transmission constraints.

3.1.6.2 Spinning Reserve Requirements

As a NERC balancing area, the Companies are required to carry contingency reserves to ensure the reliability of the grid. To meet these obligations in a least-cost manner, the Companies entered into a reserve sharing agreement with TVA. By sharing reserves with TVA, the Companies are able to reduce the amount of contingency reserves they need to carry. In the current plan, the Companies need to maintain 245 MW of contingency reserves at all times. In addition, the Companies typically carry approximately 150 MW of regulating reserves to follow load fluctuations in real time. PROSYM models these reserve requirements.

3.1.6.3 Off-System Sale Constraints

As a general rule, because hourly market prices can fluctuate, potential OSS margins from SCCTs do not justify the wear and tear associated with starting a unit in anticipation of potential OSS margins. Therefore, the Companies' SCCTs are generally only committed to meet customers' need for peak energy. For this reason, a constraint is modeled in PROSYM that reduces OSS by limiting modeled OSS when SCCTs are operating, which results in a proportion of OSS from SCCTs in line with historical volumes.

3.1.6.4 Dispatch Order Rules

Dispatch order rules determine the order in which different types of generation sources are dispatched. The majority of generation sources are dispatched economically. However, the Companies' CSR customers are not curtailed until all other company-owned sources have been exhausted. Likewise, the Companies' reserve sharing agreement gives the Companies limited and temporary access to emergency reserves that can only be dispatched after all other resources have been exhausted. The dispatch order rules enable the Companies to model these constraints.

3.2 Prepare Draft Generation Forecast

In the second part of the process used to develop the Companies' generation forecast, model inputs are loaded into PROSYM and PROSYM is used to prepare a draft generation forecast. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. The input variance analysis and comparison of the forecast to history are discussed in more detail in the following sections.

3.2.1 Input Variance Analysis

The process of performing an input variance analysis begins with the previous year's generation forecast and is completed in steps. As each input or group of inputs is updated, PROSYM is used to create a new forecast. A comparison of forecast results in each step reveals the impact of changing one input (or group of related inputs). The comparison of forecast results for each step includes a comparison of native load production costs, OSS margin, generation volumes, unit capacity factors, fuel burn, and other factors. In most cases, the change from the previous year's forecast to the current year's forecast is explained primarily by a limited number of factors. Despite this fact, the impact of all input changes is evaluated carefully. If the impact of a change is not deemed reasonable, the model inputs are adjusted and the process is repeated.

3.2.2 Comparison of Forecast to History

The goal of the generation forecasting process is to produce the most accurate forecast possible. In addition to the input variance analysis, numerous elements of the forecast are compared to historical trends to further assess the reasonableness of the forecast. In many cases, the forecast should be consistent with historical trends. When this is not the case, it is important to ensure that forecasted deviations from historical trends are reasonable. The following is a sample of forecast elements that are compared to historical data.

- Annual/monthly/hourly generation by generation source
- Annual/monthly fuel burn by generation source
- Annual startup fuel by generation source
- Annual SCCT starts/run hours
- Annual/monthly/hourly OSS volumes by peak type
- Annual/monthly/hourly OSS margin by peak type
- Annual/monthly/hourly economy purchase volumes by peak type
- Annual SO_2/NO_x emissions
- Annual/monthly capacity factor by generation source
- Annual/monthly intercompany transaction volumes
- Annual/monthly dispatch order

3.3 Review

In the third part of the process used to develop the Companies' generation forecast, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives.

The following groups are primary consumers of the forecast results and review various elements of the forecast to help ensure that the results are reasonable:

- Corporate Fuels and By-products: The Corporate Fuels and By-Products group reviews the fuel burn forecast by generating station and fuel type.

- Power Supply: The Power Supply group reviews the forecasts of OSS margin, OSS volumes, and economy purchase volumes by peak type.
- Plant Management: Plant managers review the forecasts of generation by station and fuel type.

3.4 Deliverables

After forecast reviews are completed, the forecast deliverables are distributed to the groups within the company who use the forecast to prepare financial budgets. The following is a list of key deliverables:

- Generation Forecast
- Fuel Burn Forecast
- Fuel Expense Forecast
- OSS Margin Forecast
- Emissions Forecast

LG&E KU

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2017 Business Plan
Generation & OSS Forecast

Generation Planning & Analysis
August 12, 2016

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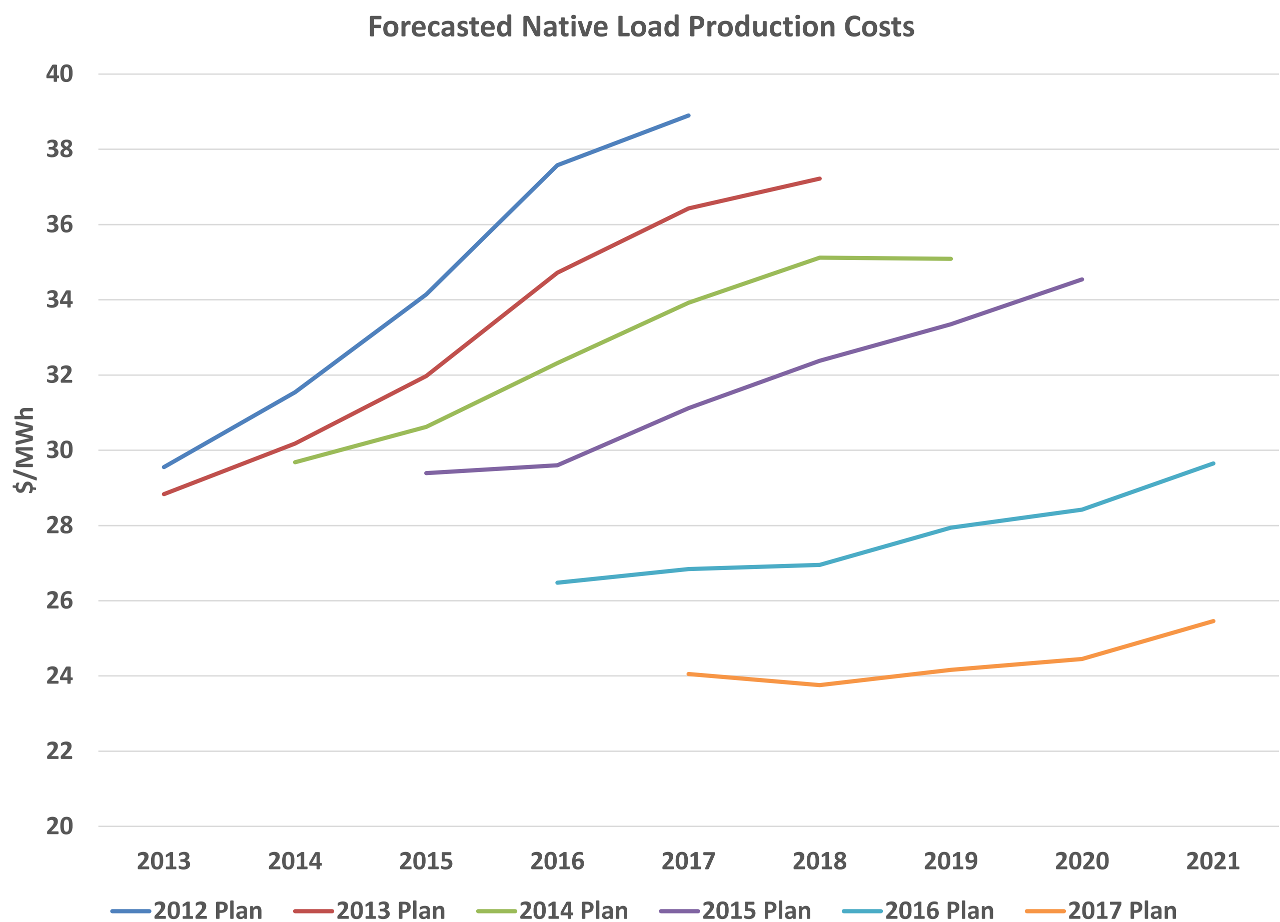
2017 Plan Summary

- Compared to the 2016 Plan, native load production costs ($/MWh) are notably lower in the 2017 Plan; OSS contribution is lower in 2017-2018 and higher in 2019-2021
  - *Lower fuel and market electricity prices drive differences in production costs throughout planning period and in OSS through 2018*
  - *Higher OSS margins after 2018 attributed to better aligning OSS modeling with AFB*

Native Load Production Costs ($/MWh)	2017	2018	2019	2020	2021	CAGR
2016 Plan	26.84	26.95	27.94	28.42	29.65	2.5%
2017 Plan	24.05	23.76	24.16	24.45	25.46	1.4%

OSS Contribution (100%, $M)	2017	2018	2019	2020	2021
2016 Plan	3.2	3.0	3.4	3.2	2.3
2017 Plan	1.7	2.2	3.6	4.4	4.7

Forecasted native load production costs continue pattern of Plan over Plan declines



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Key Changes in Planning Assumptions & Inputs vs. 2016 Plan

- Commodity prices are lower in 2017-2021
  - *Coal prices are 7-12% lower*
  - *Natural gas prices are 9-18% lower*
  - *Electricity prices are 13-17% lower*

- Native load energy requirements are lower (starting at 1.9% lower in 2017 and growing to 3.0% lower in 2021)
  - *Absent unit retirements, no need for new capacity throughout the 30-year forecast period*

- Variable O&M forecast is lower at Trimble, Mill Creek, and Ghent

- NOx emission rates updated to target CSAPR II compliance

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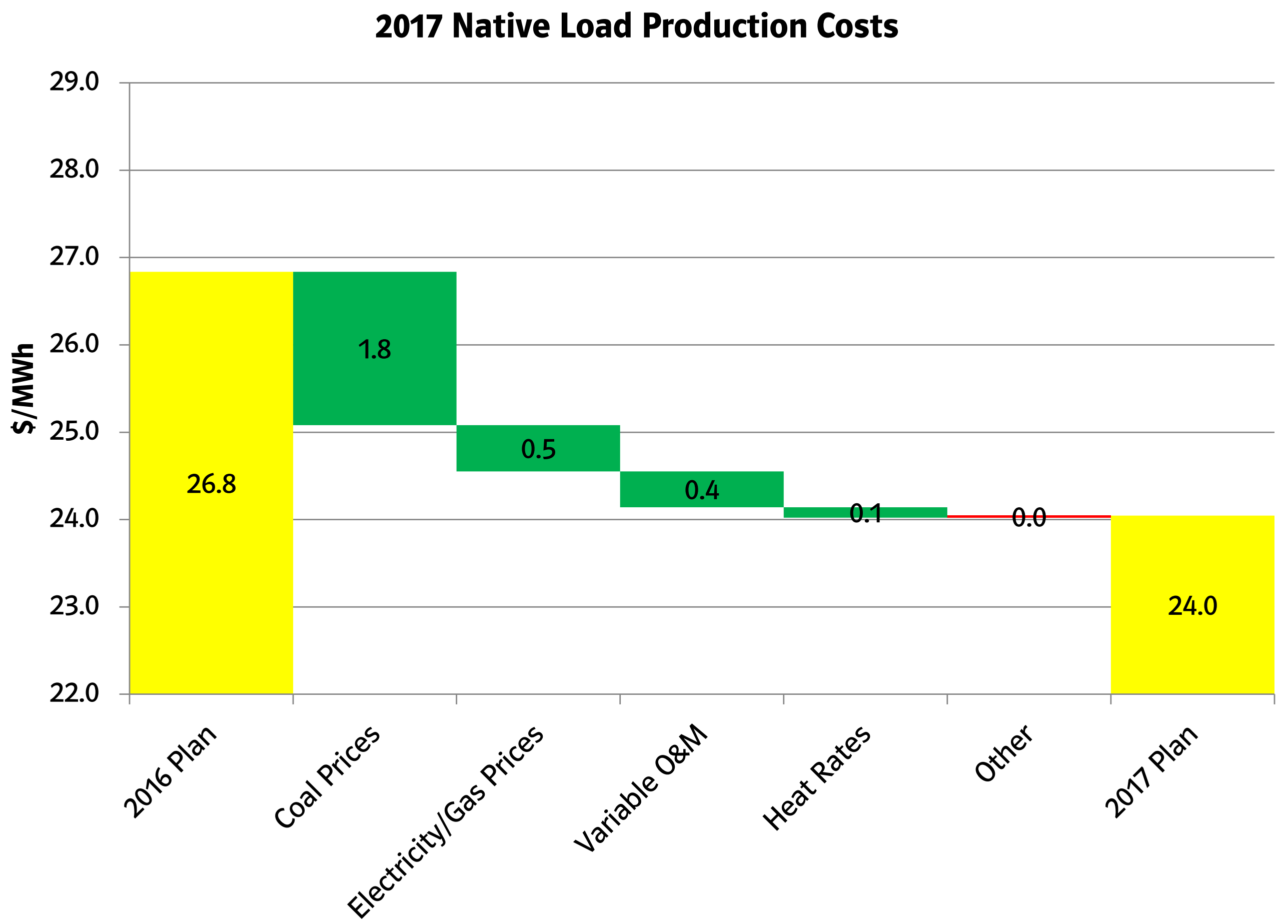
In 2017-2019, lower coal and gas prices are the key drivers of lower native load production costs



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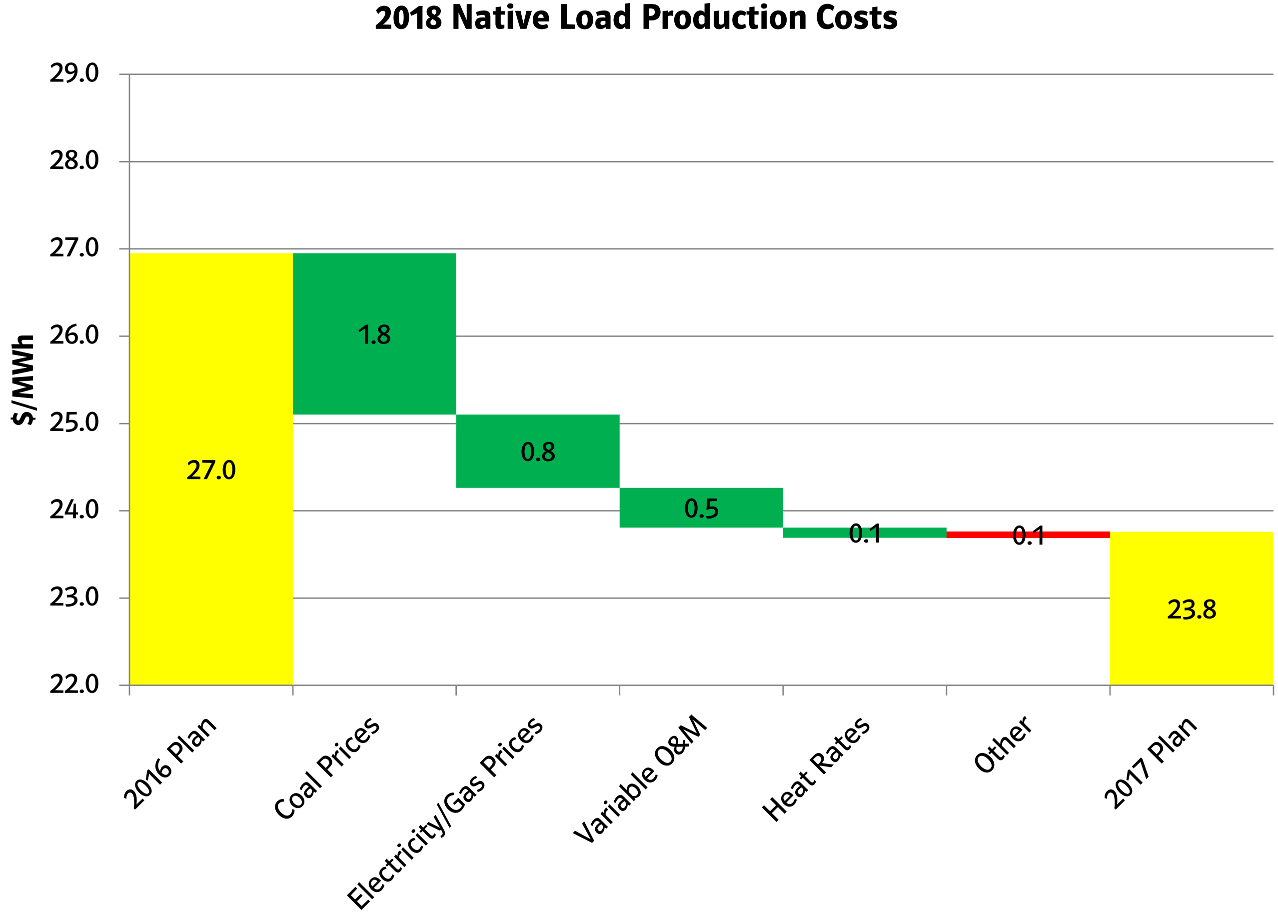
In 2017-2019, lower coal and gas prices are the key drivers of lower native load production costs



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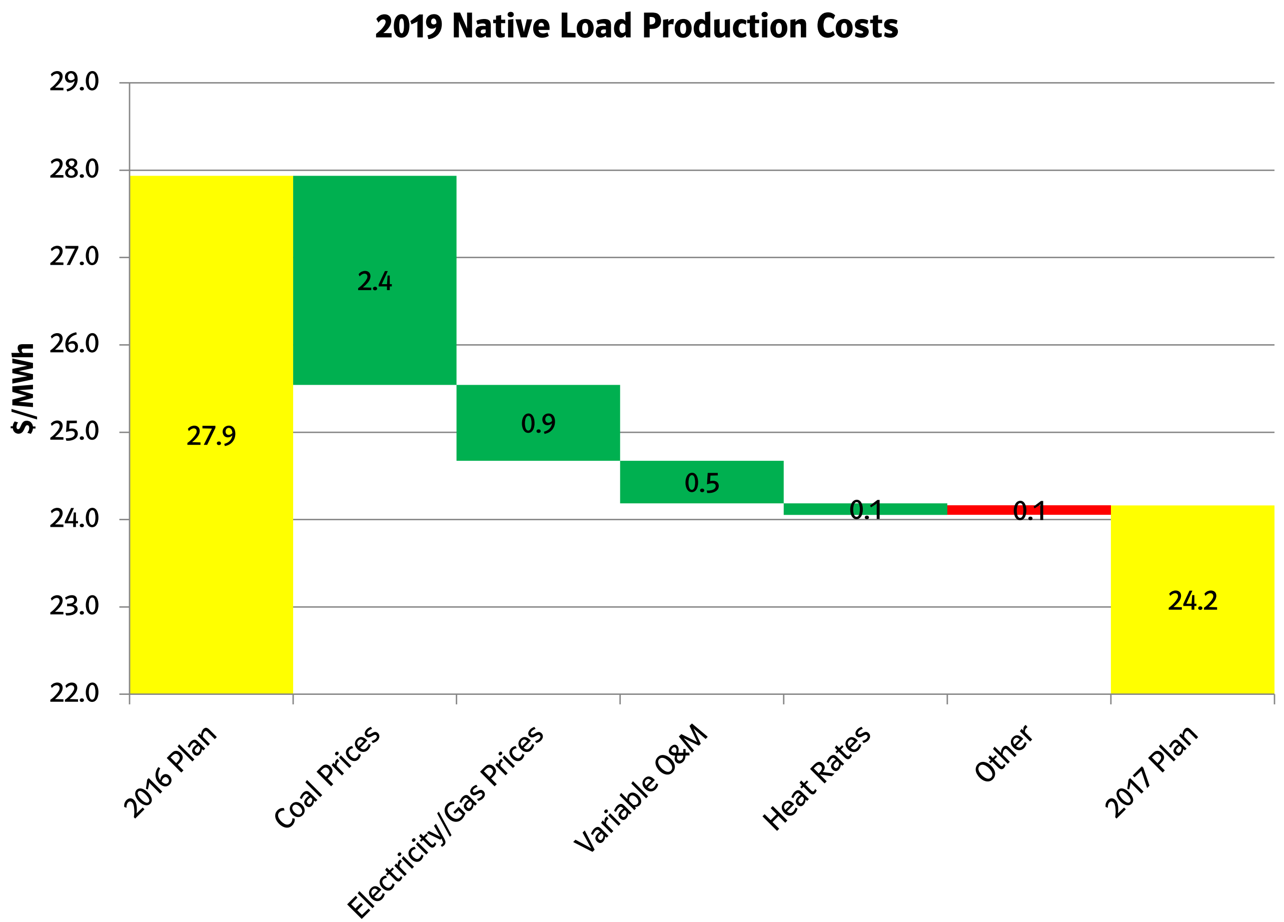
In 2017-2019, lower coal and gas prices are the key drivers of lower native load production costs



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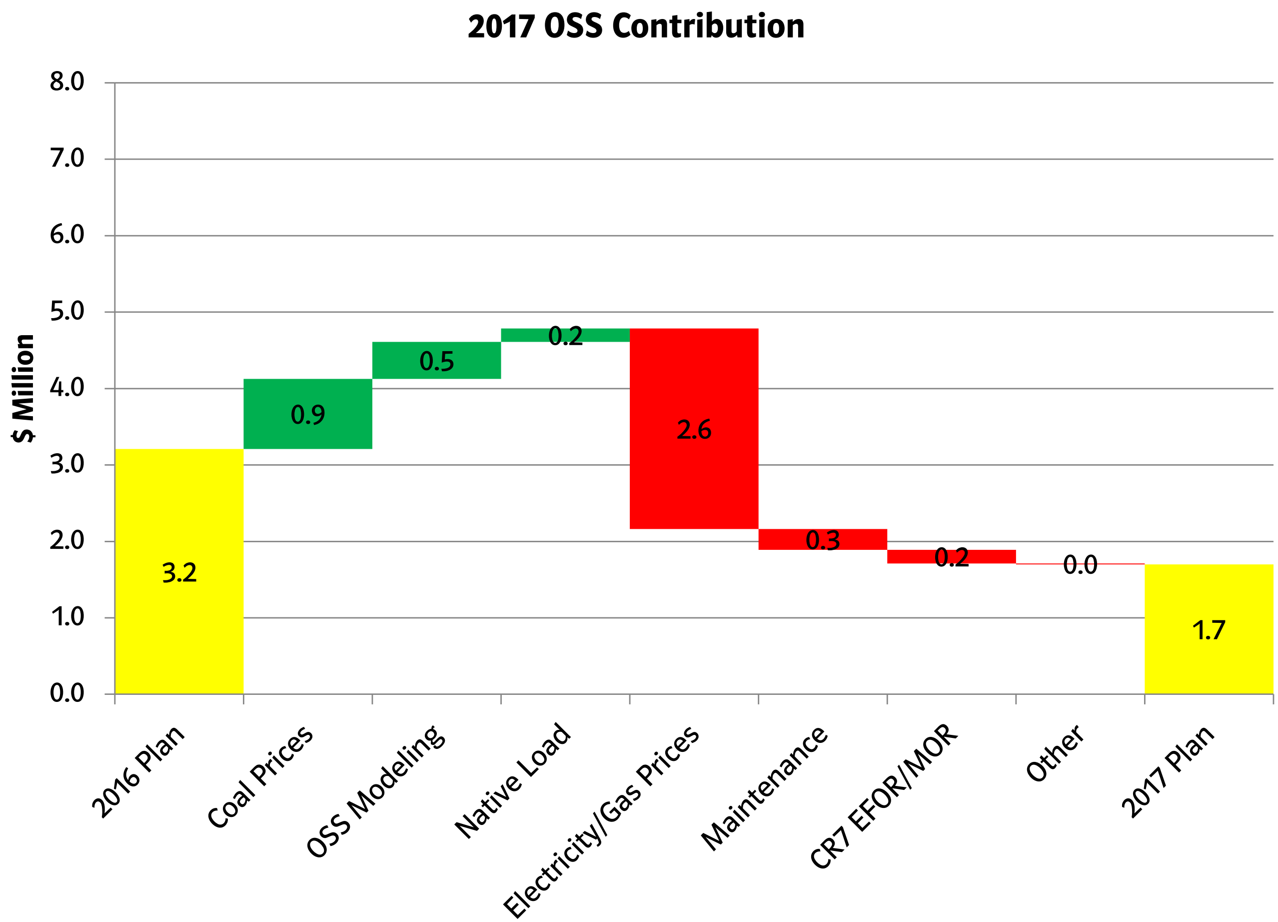
In 2017-2018, lower market electricity prices drive lower OSS contribution



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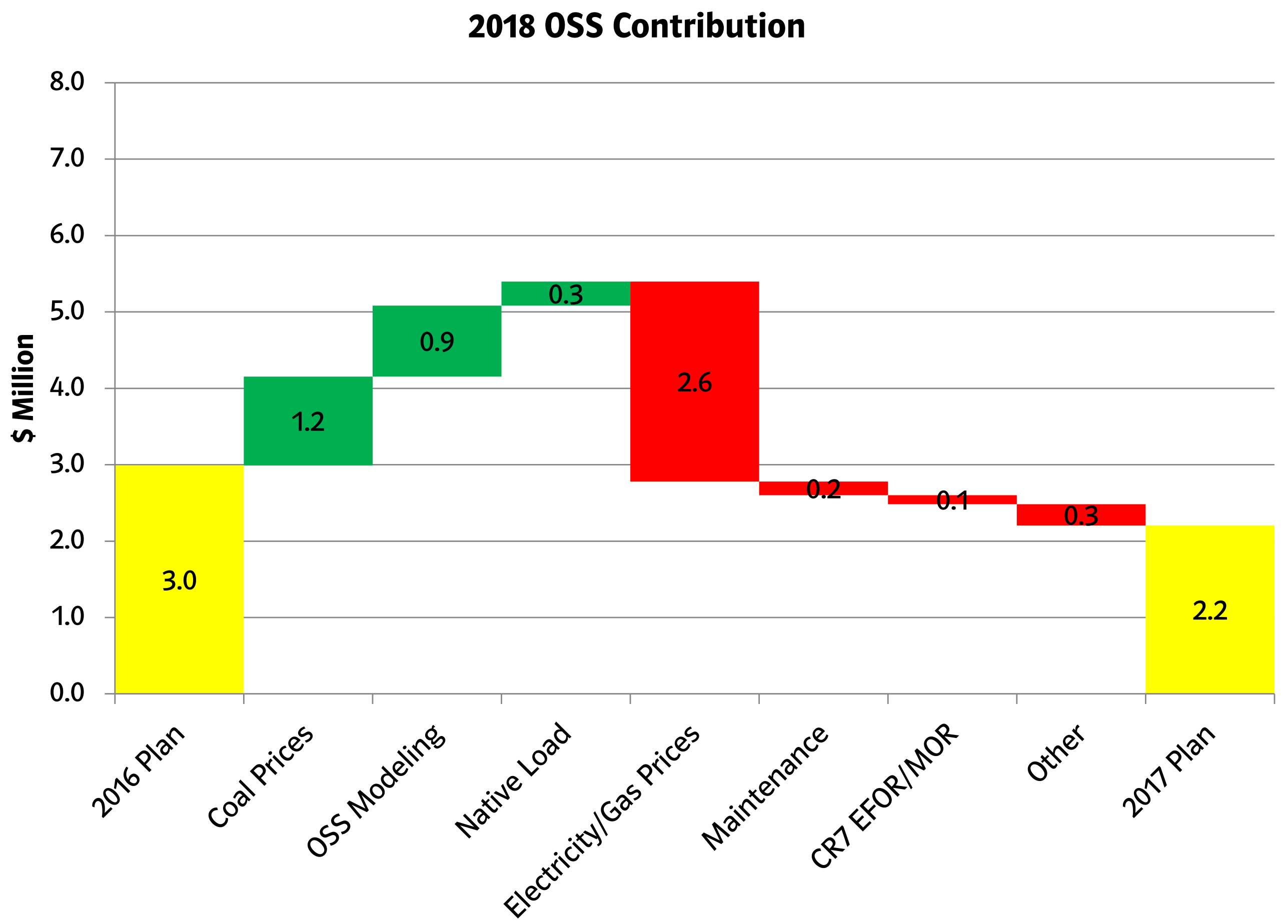
In 2017-2018, lower market electricity prices drive lower OSS contribution



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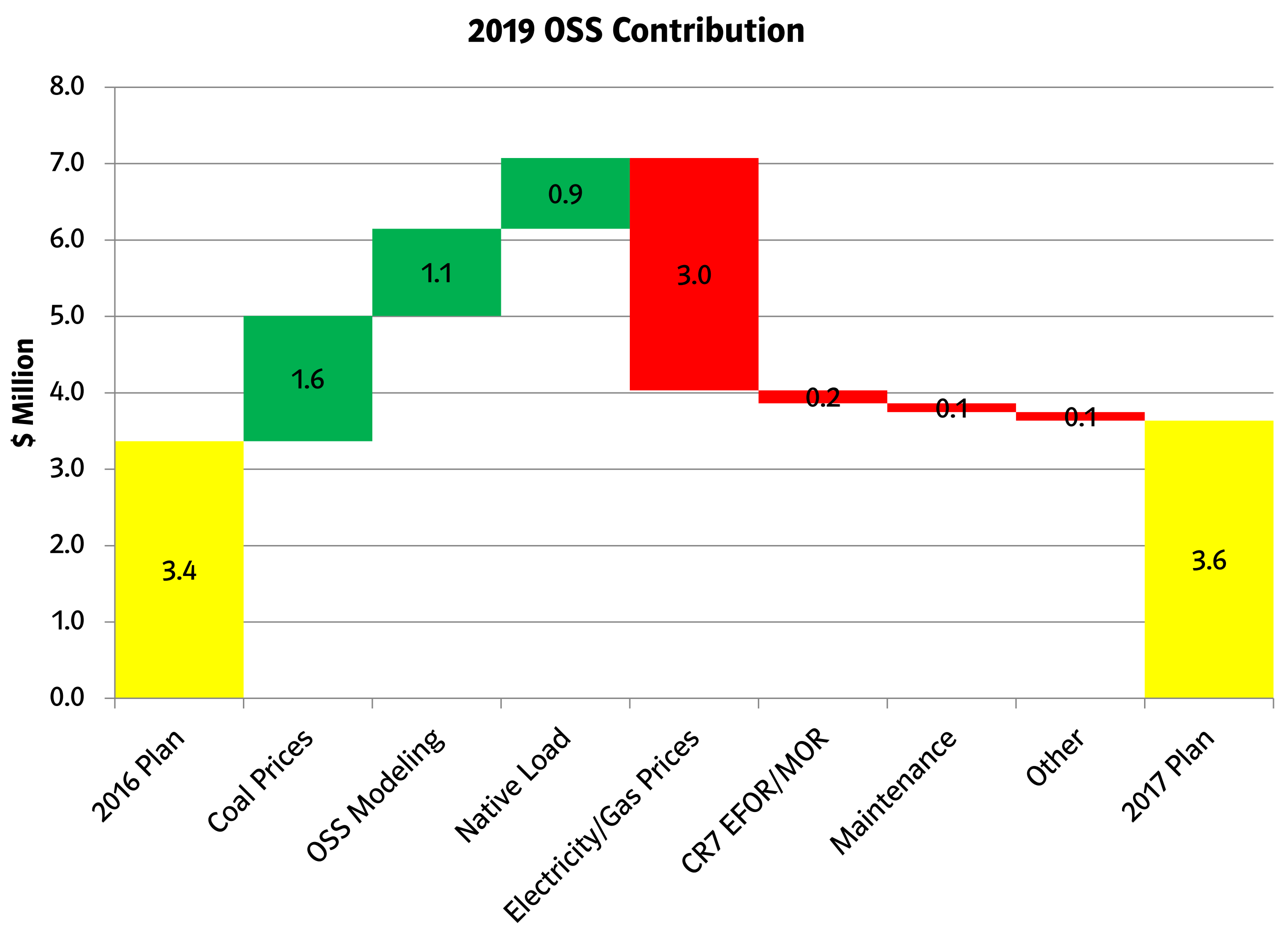
In 2019, lower market electricity prices offset lower coal prices, lower load, and OSS modeling changes, resulting in a small increase to OSS contribution



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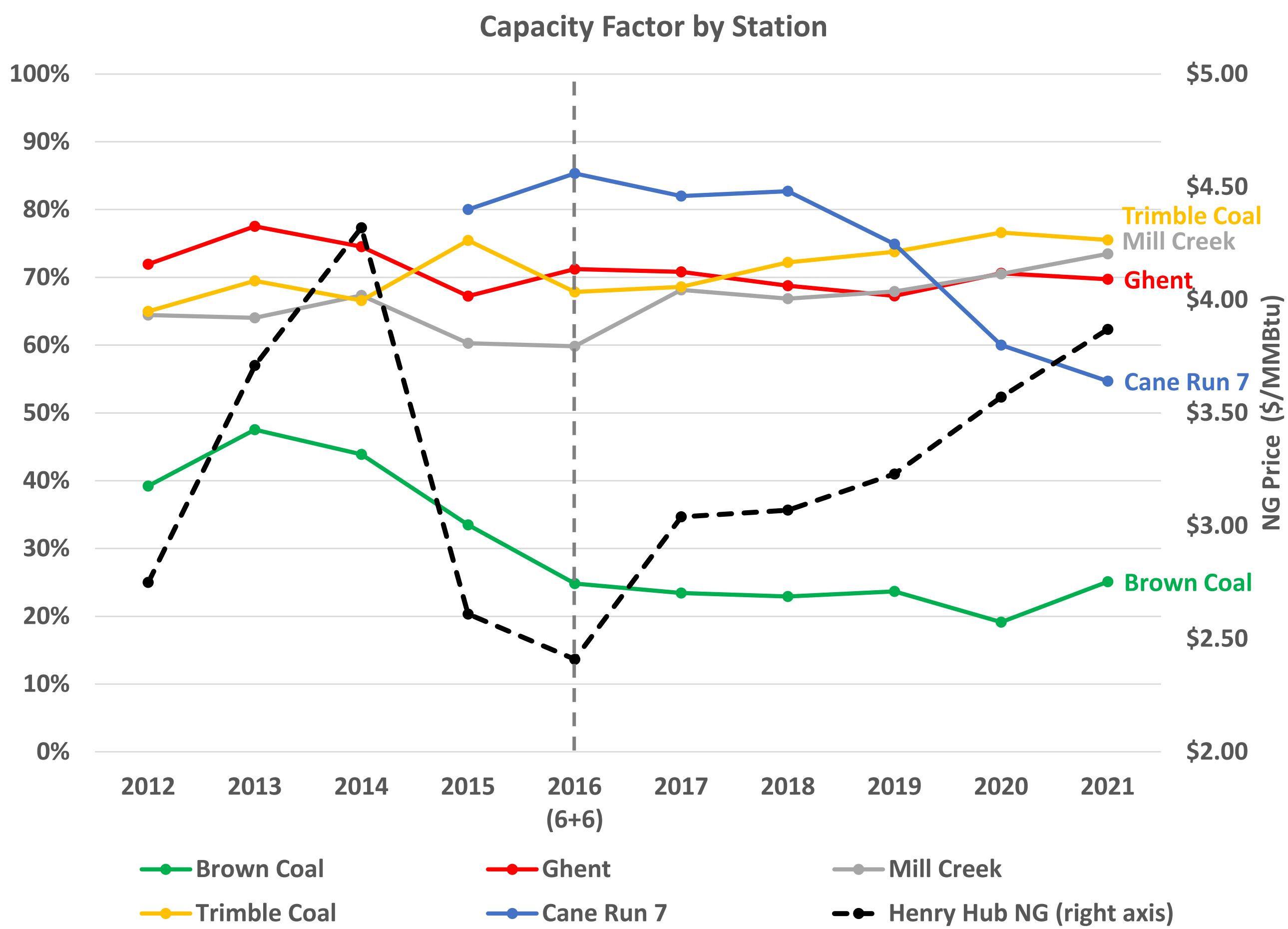
As gas prices increase, generation shifts from CR7 to Ghent, Mill Creek, and Trimble County



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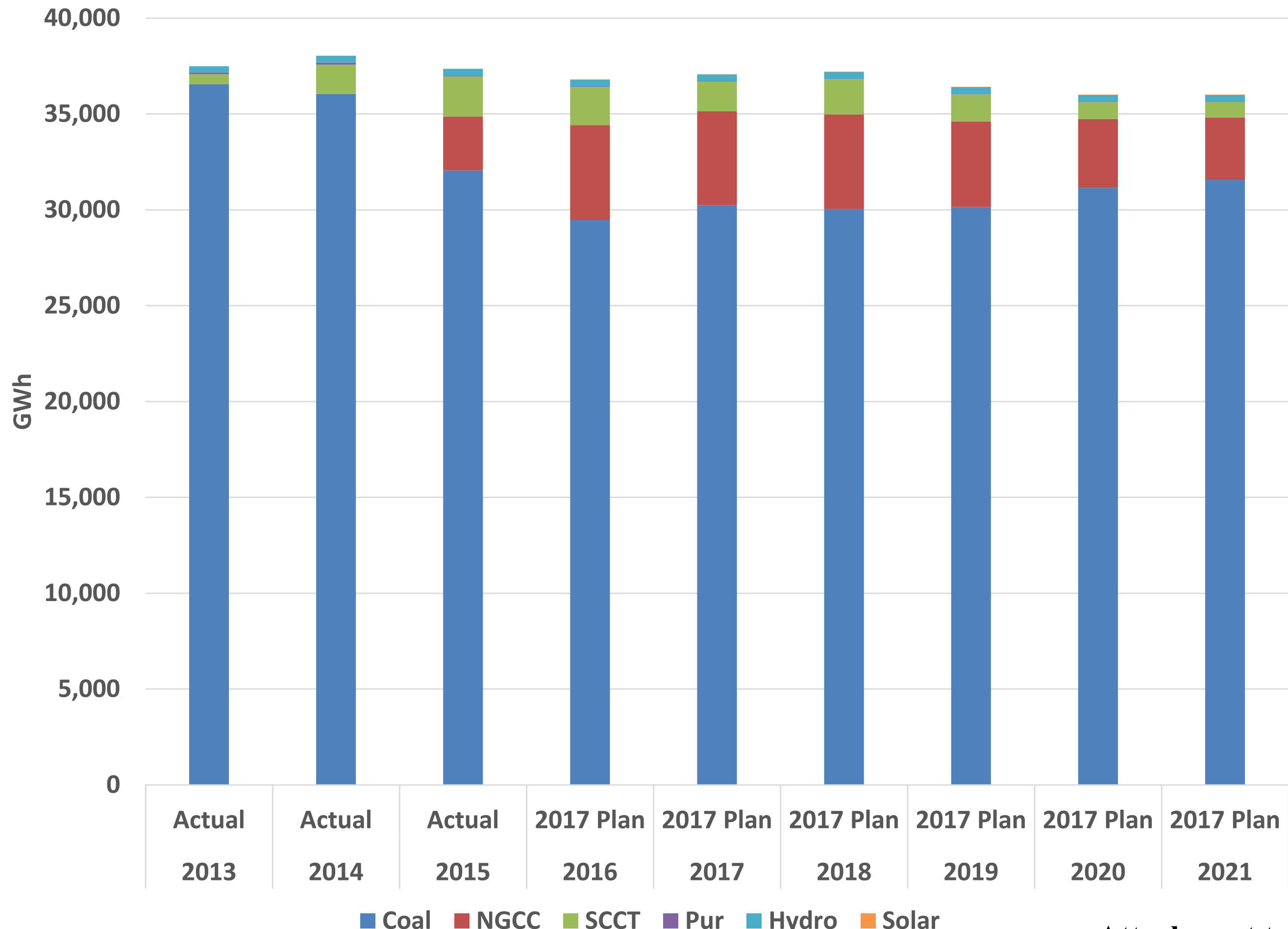
Coal generation increases over time as gas prices increase



Year	Coal %
2013	97%
2014	95%
2015	86%
2016	80%
2017	82%
2018	81%
2019	83%
2020	86%
2021	88%

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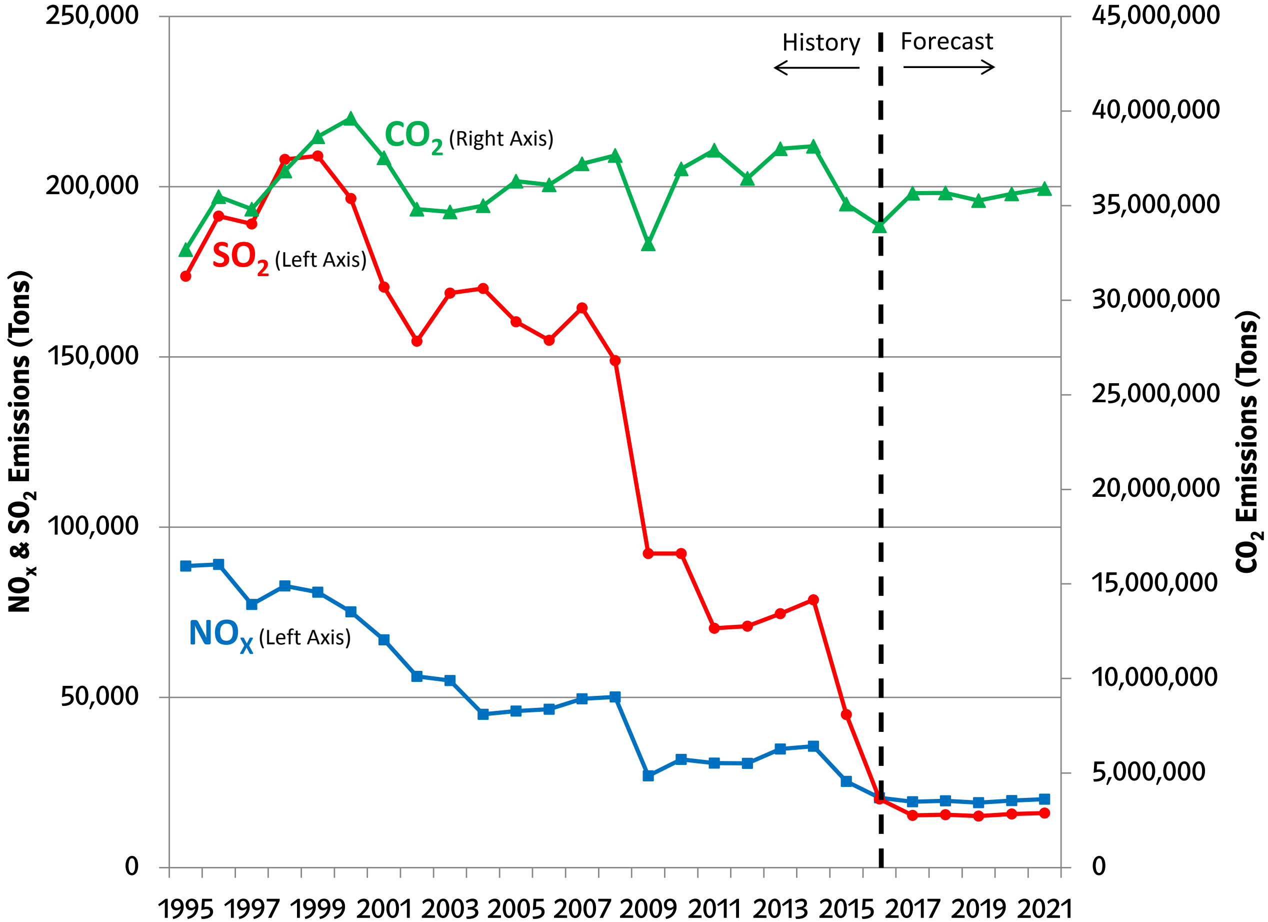
Emissions have decreased with addition of controls



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CSAPR II Compliance (Ozone Season NOx)

- CSAPR Update Rule (CSAPR II)
  - *Proposed Nov. 2015; expected final Q3 2016; effective 2017*
  - *Further restricts ozone season NOx (~30% lower for KY)*
  - *Further restrictions on banking*
- Expect 2017 allocations to slightly exceed emissions
- 2017 projections:
  - *Starting bank: 7,726 tons*
  - *Allocations: 8,074 tons*
  - *Emissions: 7,948 tons*
  - *Allowance Price: $600/ton*
- Requires management of SCR operation, dispatch, and emissions allowances
- Developing risk management plan to minimize compliance costs

Key Risks and Uncertainties

- Compliance plan for effluent guidelines
- Final resolution of Clean Power Plan (CPP) litigation
  — *Likely no impact to generation in 5-year Plan horizon*
  — *Likely impact to generation dispatch and/or resource planning beyond 5-year Plan horizon*
- Landfill capacity
  — *Trimble County landfill permitting on track*
  — *Next phase of Mill Creek landfill expected to be deferred through increased beneficial use*
- Jefferson County NAAQS attainment status

Key Takeaways

- Lower native load costs yields lower costs for ratepayers
  - *Production cost savings of $110-170M per year vs. 2016 Plan*
- Changes in gas prices could significantly alter CR7's utilization
- Load growth is flat; absent unit retirements, no need for new capacity
- CSAPR II compliance plan appears manageable through collaborative effort

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Appendix

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2017 Plan – Assumptions

- Modeled EFOR assumptions are based on historical EFOR values ('target' EFORs will continue to be the basis for KPI reporting)
  - *CR7 modeled EFOR in 2017 decreased from 5.0% to 3.0%*
  - *CR7 modeled MOR increased to 5.9% (previously not modeled)*
  - *TC2 modeled EFOR in 2017 increased from 6.0% to 7.6%*
- NOx emission rates and SCR operation reflect changes to enable CSAPR II compliance
- Expansion plan:
  - *Target reserve margin: 16-21%*
  - *Bluegrass PPA (165 MW): May 2015 – April 2019*
  - *No expansion units planned at this time*
- Trimble County 1 & 2 start fuel changes from oil to gas (TC2 in spring 2017; TC1 in fall 2019)
- Cane Run 7 Long-Term Service Agreement (LTSA) is the greater of $771/hour or $22,330/start (2015$)

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2017 Plan – Assumptions

- Spinning reserve requirements:
  - *Contingency: Spinning 245 MW (100 MW of 245 MW is supplemental - supplied by quick-start units)*
  - *75 MW regulating*
  - *75 MW NAS*
- Turbine overhaul schedule:
  - *2017: TC1*
  - *2018: GH3, TC2, BR2, MC2*
  - *2019: GH2, MC3, MC1*
  - *2020: BR3*
  - *2021: GH4*
- CT Modeling
  - *Paddy's Run 11-13 were historically unavailable in winter due to insufficient gas pressure; beginning fall 2016, the Paddy's Run units will be available year-round following the completion of the new pipeline project*
  - *Forecast reflects cost of CT maintenance in dispatch considerations*
  - *Forecast reflects run hour limits due to environmental constraints*

PPL companies

2017 Plan – Assumptions

- Market electricity prices
  - *Consistent with July-approved prices*
  - *Hourly prices are correlated with forecasted load shape*
  - *Winter premium adjusted out of Jan/Feb pricing*

- Revised OSS modeling constraints to be more consistent with history
  - *Model does not allow off-system sales while Paddy's Run or Brown CTs are generating (relaxed constraint to allow OSS while Trimble CTs on; better reflects OSS with low coal/gas price spreads)*
  - *OSS limited to 400 MW/hr in peak period, 350 MW/hr in weekend period, and 150 MW/hr in off-peak period*

- Revised purchase modeling constraints to be more consistent with history
  - *Promoted dispatch order of purchases during off-peak hours*
  - *Hourly purchases limited to 200 MW/hr in all peak periods based on historical transmission constraints*

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PPL companies

2017 Plan – Assumptions

CSAPR Emission Allowance Prices ($/ton emitted)

Year	Annual NOx	Seasonal NOx	SO_2
2017	141	600	8
2018	129	530	6
2019	111	445	5
2020	89	341	5
2021	99	276	30
2022	90	561	23
2023	65	477	14
2024	51	406	11
2025	41	345	9
2026	19	293	8

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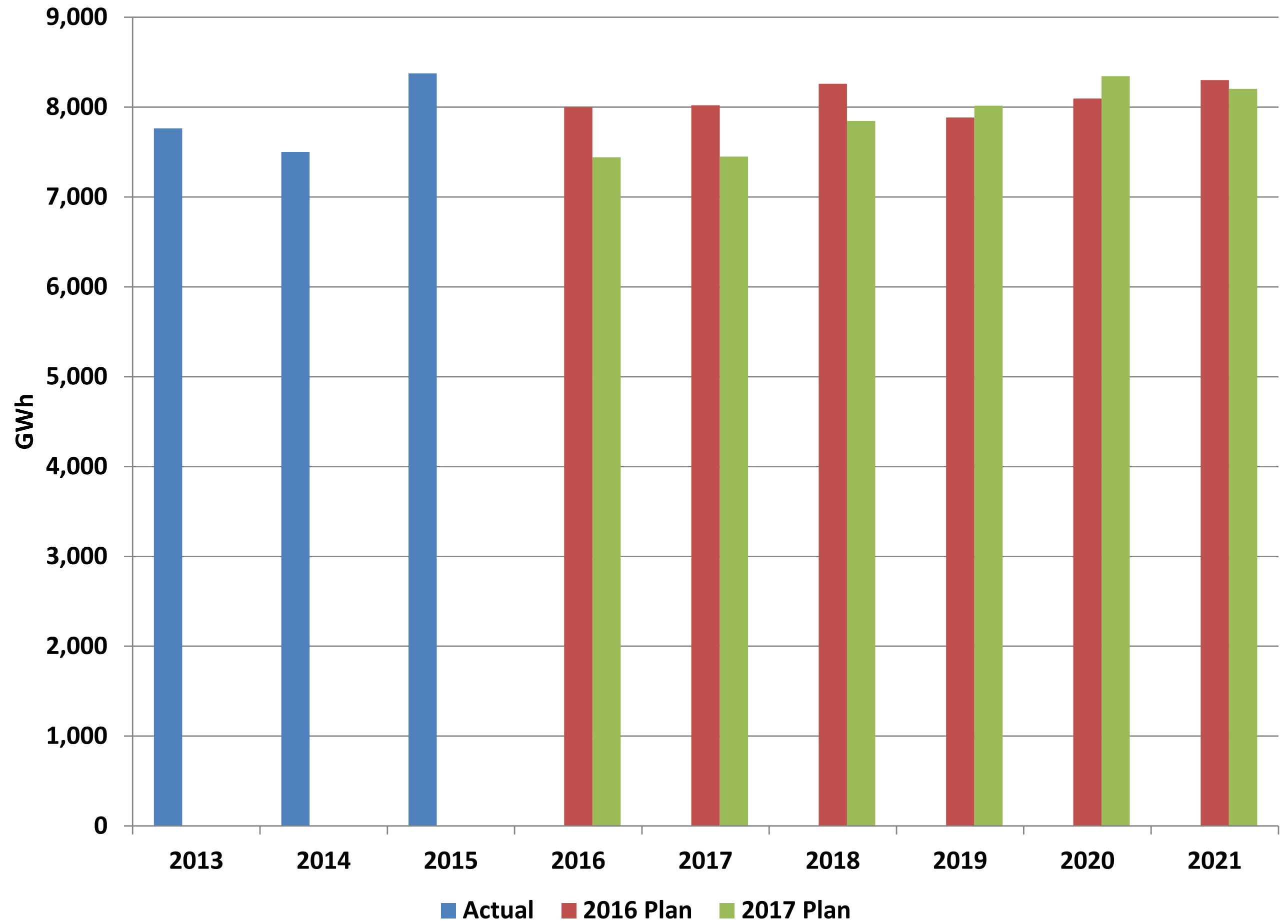
PPL companies

Trimble coal generation is lower mostly due to increased maintenance (2017 and 2021) and higher EFOR for TC2; lower coal prices result in increased generation beginning in 2019



2017 Plan in 2016: 6 + 6
100% TC

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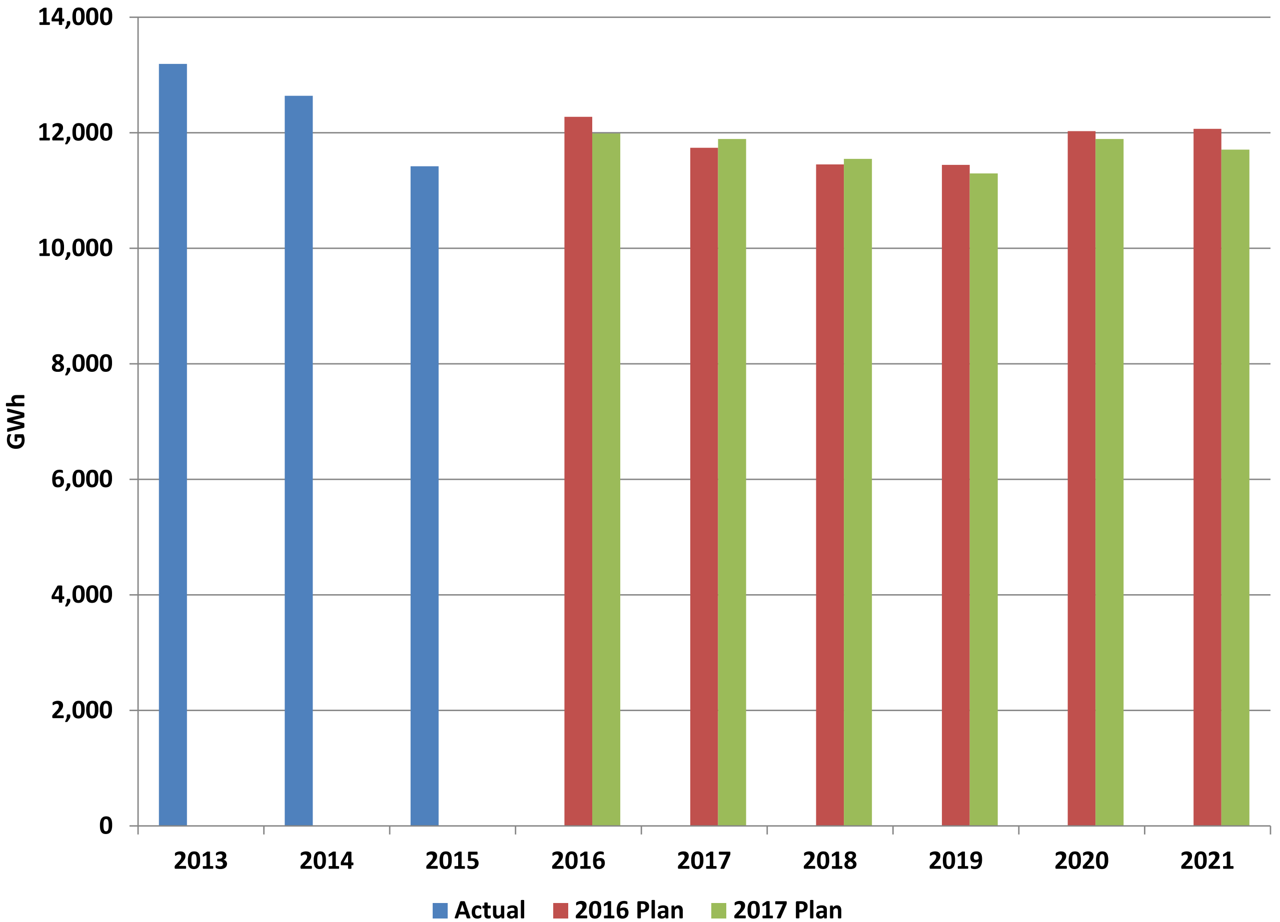
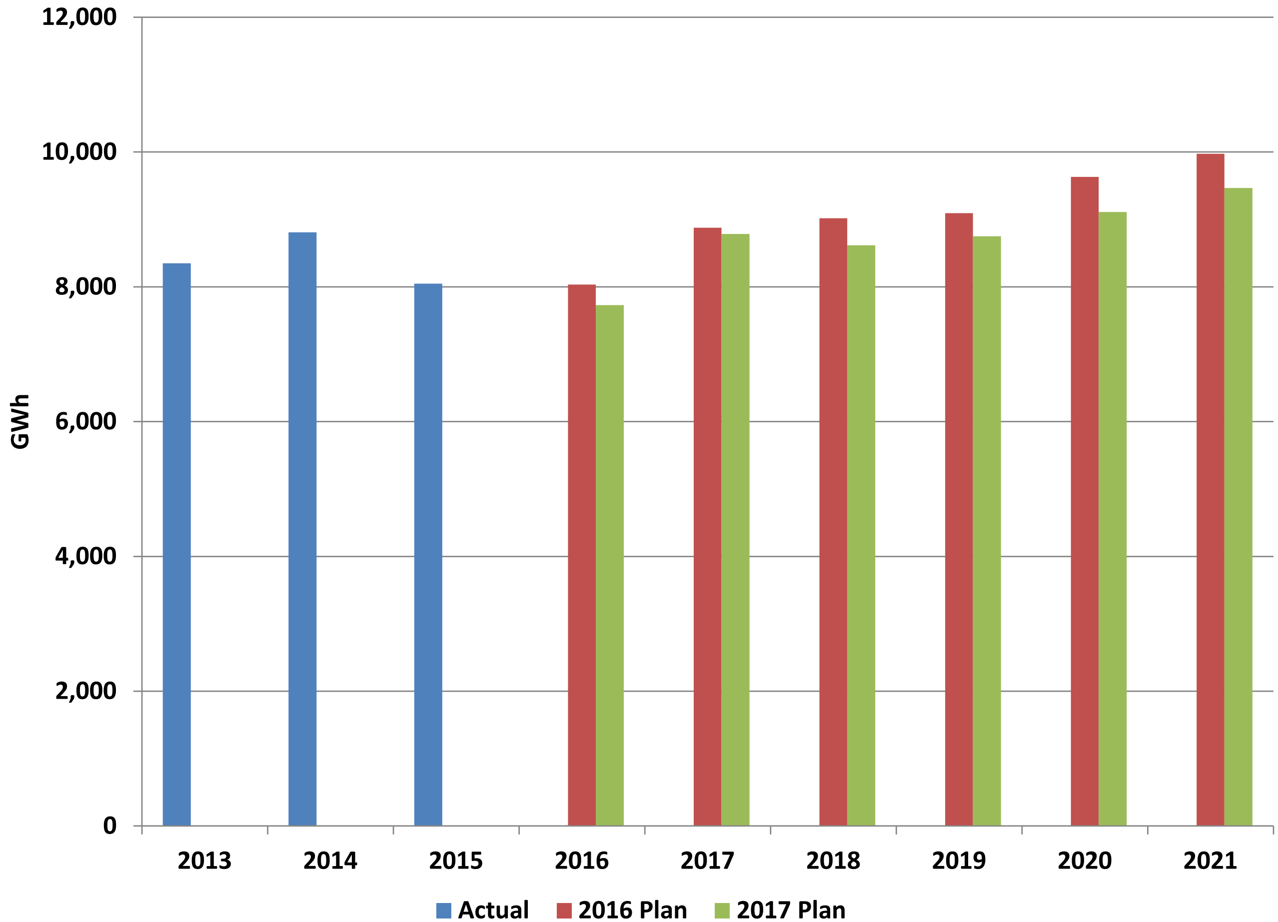
LG&E KU
PPL companies

Ghent generation is largely unchanged due to offsetting impacts of coal and gas price decreases



2017 Plan in 2016: 6 + 6

Mill Creek generation decreases due to lower coal/gas price spreads and load



2017 Plan in 2016: 6 + 6

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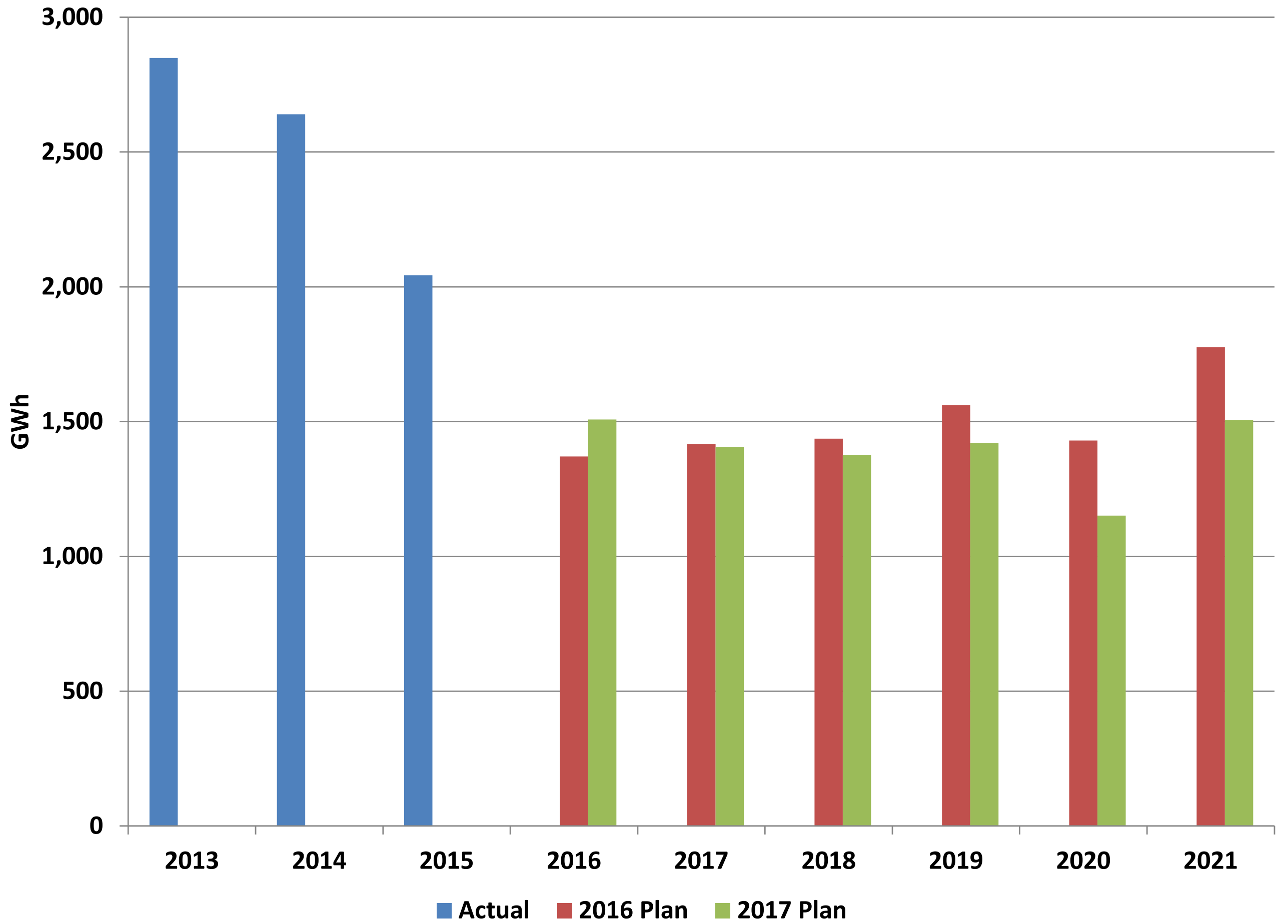
PPL companies

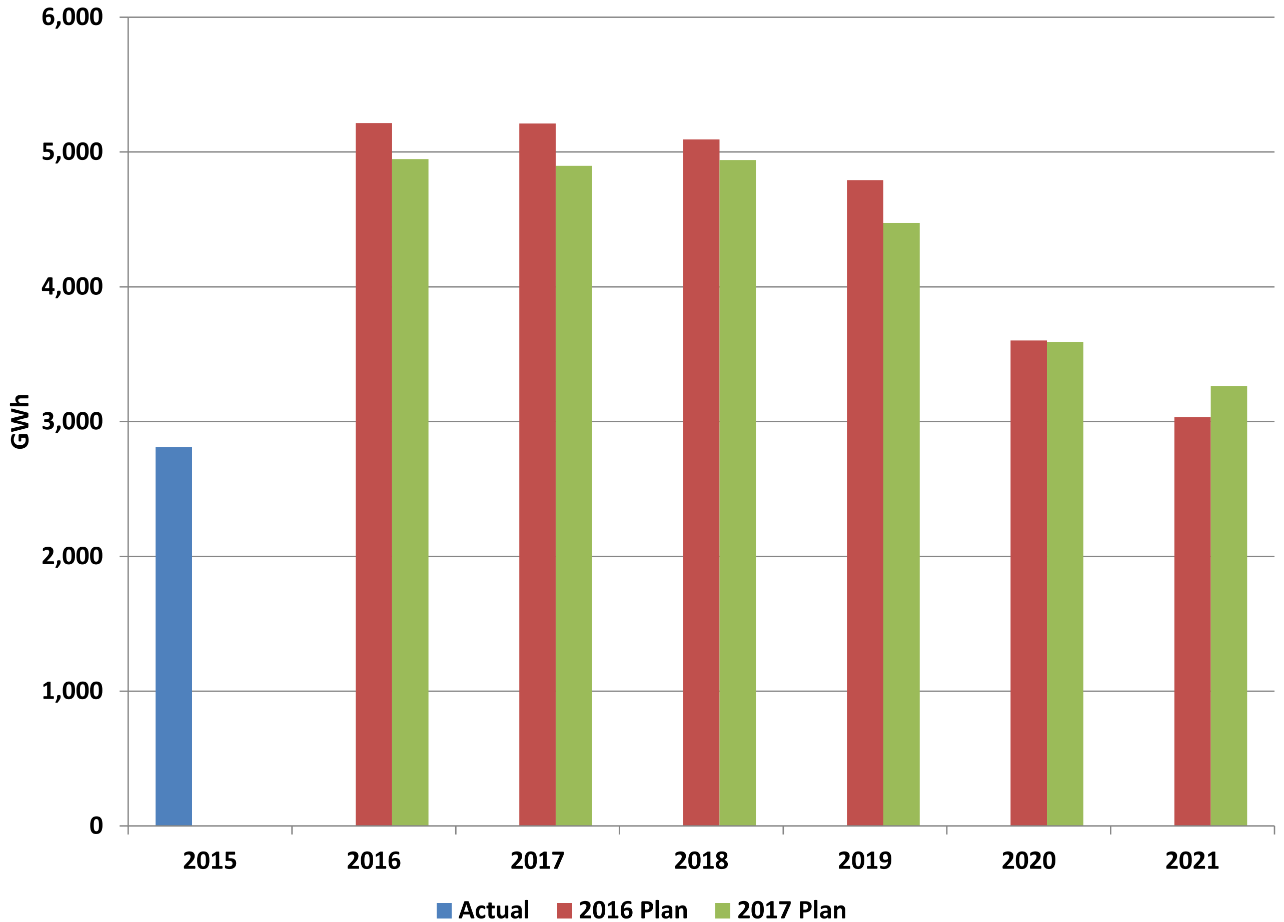
Brown coal generation decreases in 2018-2021 due to lower gas prices and load



2017 Plan in 2016: 6 + 6

PPL companies

Cane Run 7 generation decreased slightly due to maintenance outage modeling and load, but increased in later years due to lower gas prices



2017 Plan in 2016: 6 + 6
CR7 commissioned in June 2015

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SCCT generation relatively unchanged

CT Generation *(GWh)*

	ACTUAL				(6+6)	2017 Plan				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BR5, 8-11	24	14	124	430	317	64	95	50	24	22
BR6, 7	223	93	383	367	29	126	157	134	78	81
PR13	57	29	104	181	35	194	186	164	131	95
TC5-10	1,034	366	893	1,001	417	1,112	1,323	1,037	649	605
	1,338	**502**	**1,504**	**1,979**	**798**	**1,495**	**1,761**	**1,384**	**883**	**802**

2016 Plan				
1,561	**1,636**	**1,309**	**1,004**	**725**

CT Starts *(# starts)*

	ACTUAL				(6+6)	2017 Plan				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BR5, 8-11	103	78	150	384	190	126	166	106	97	85
BR6, 7	185	119	207	97	21	106	145	107	96	98
PR13	68	28	68	124	31	202	199	156	131	107
TC5-10	626	499	674	563	260	884	941	850	733	714
	982	**724**	**1,099**	**1,168**	**502**	**1,318**	**1,451**	**1,219**	**1,057**	**1,004**

2016 Plan				
1,318	**1,374**	**1,240**	**1,107**	**951**

CT Generation (GWh)/Start

	ACTUAL				(6+6)	2017 Plan				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BR5, 8-11	0.2	0.2	0.8	1.1	1.7	0.5	0.6	0.5	0.2	0.3
BR6, 7	1.2	0.8	1.9	3.8	1.4	1.2	1.1	1.2	0.8	0.8
PR13	0.8	1.0	1.5	1.5	1.1	1.0	0.9	1.0	1.0	0.9
TC5-10	1.7	0.7	1.3	1.8	1.6	1.3	1.4	1.2	0.9	0.8
	1.4	**0.7**	**1.4**	**1.7**	**1.6**	**1.1**	**1.2**	**1.1**	**0.8**	**0.8**

2016 Plan				
1.2	**1.2**	**1.1**	**0.9**	**0.8**

CT Run Hours/Start

	ACTUAL				(6+6)	2017 Plan				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BR5, 8-11	4.3	3.8	15.1	13.9	18.7	7.4	8.8	8.1	4.5	4.8
BR6, 7	10.1	8.0	18.7	29.0	11.5	8.9	8.2	9.7	7.0	7.1
PR13	6.9	7.9	12.0	10.9	8.4	7.0	6.7	7.8	8.0	7.8
TC5-10	11.9	7.7	13.4	12.6	11.5	8.6	9.8	8.7	7.1	6.9
	10.4	**7.3**	**14.5**	**14.2**	**14.0**	**8.3**	**9.1**	**8.7**	**6.9**	**6.9**

2016 Plan				
8.6	**9.2**	**8.4**	**8.1**	**7.3**

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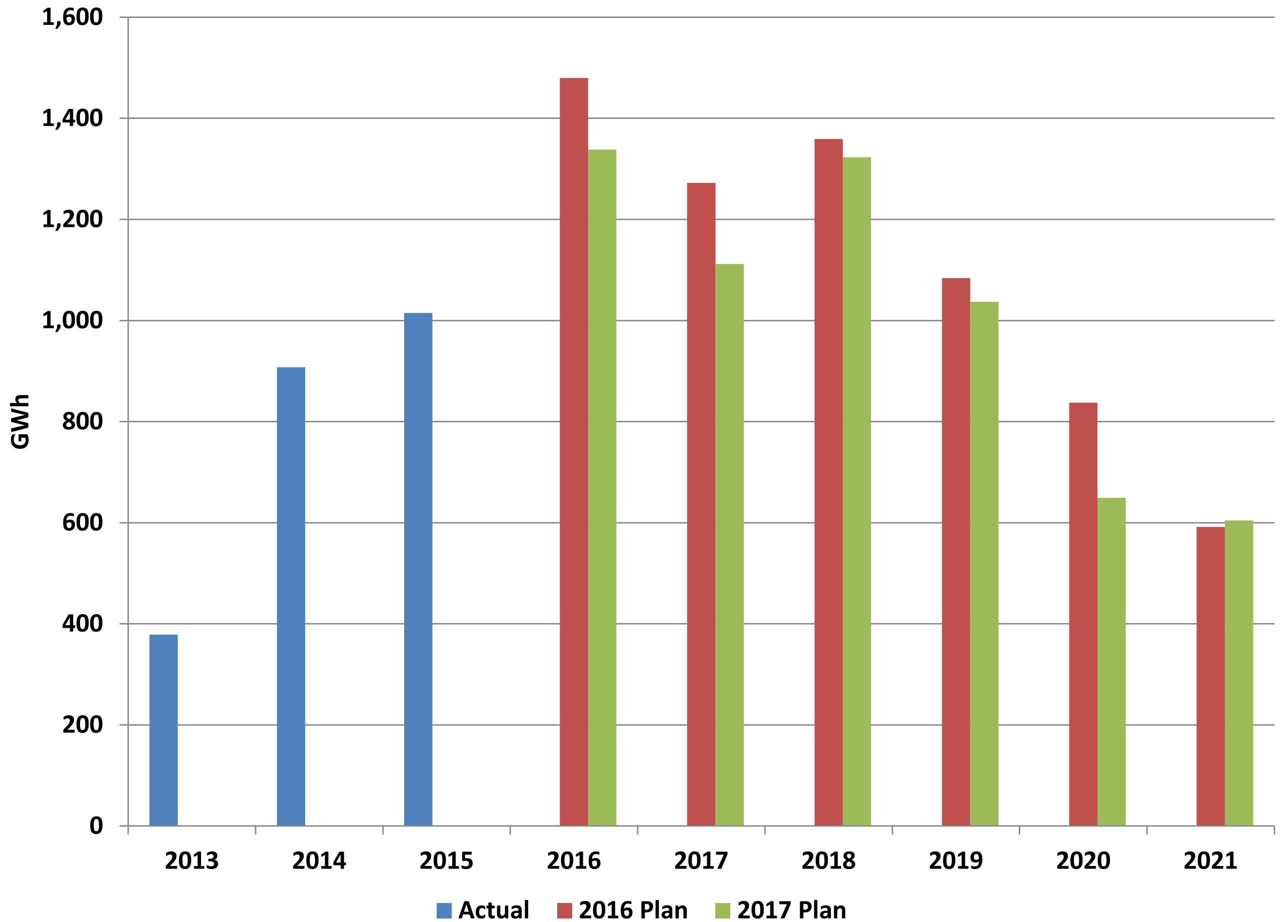
PPL companies

Trimble CT generation decreases mostly due to lower load and lower coal prices



2017 Plan in 2016: 6 + 6

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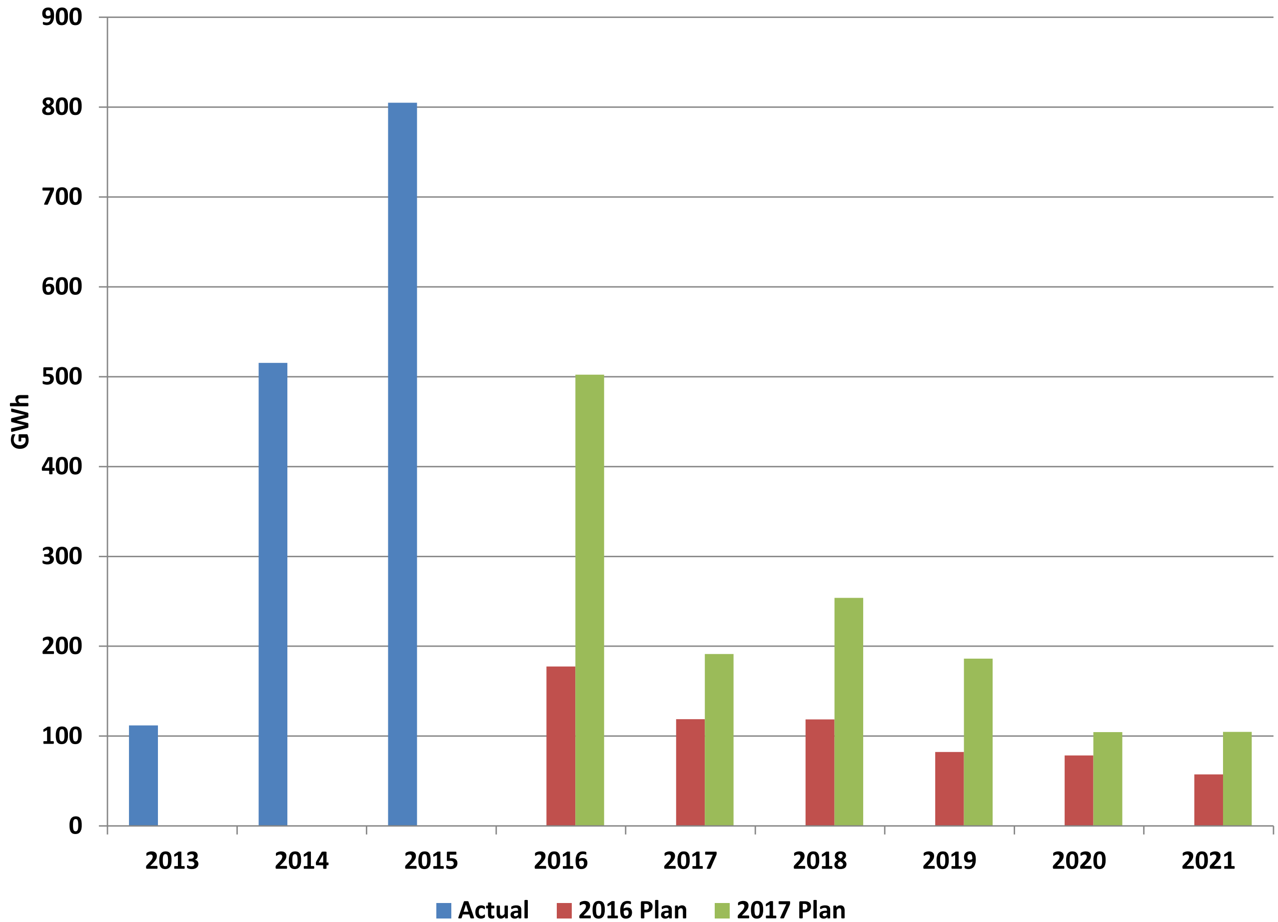
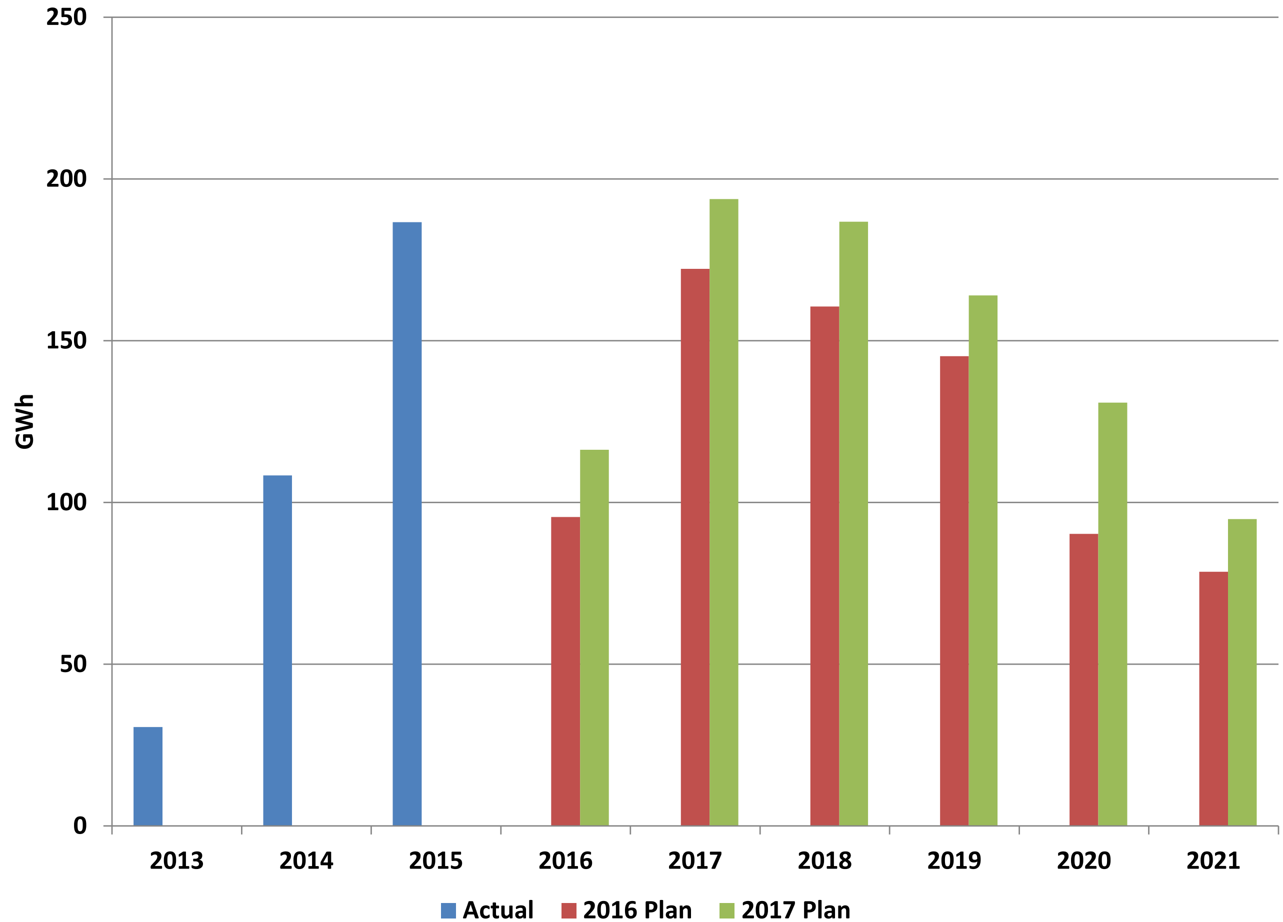
PPL companies

Brown CT generation increases mostly due to relative changes in CT maintenance costs



2017 Plan in 2016: 6 + 6

Paddy's Run generation increases mostly due to lower gas prices



2017 Plan in 2016: 6 + 6

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PPL companies

Capacity Factor by Unit

	History				6+6	2016 Plan					2017 Plan				
(%)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021
Brown 1	35	41	40	22	22	19	21	20	25	28	16	15	18	12	17
Brown 2	49	60	52	42	27	26	24	28	27	33	25	25	27	24	28
Brown 3	36	44	42	33	25	24	25	24	25	29	25	24	24	19	26
Ghent 1	75	78	77	60	74	72	66	68	69	73	74	72	72	70	72
Ghent 2	72	83	79	60	72	60	64	56	66	69	68	72	62	71	72
Ghent 3	78	77	72	71	63	76	70	75	76	78	69	61	67	69	70
Ghent 4	63	72	69	78	76	71	73	72	72	67	73	70	68	73	65
Mill Creek 1	76	55	74	56	67	67	73	71	80	71	66	72	63	73	72
Mill Creek 2	55	72	67	55	61	73	69	76	68	82	66	60	72	67	74
Mill Creek 3	76	64	78	63	52	64	72	62	77	75	64	72	61	71	69
Mill Creek 4	54	64	55	64	62	73	69	75	75	82	75	65	76	72	79
OVEC	64	56	58	56	59	51	52	53	54	55	60	55	55	54	56
Trimble County 1	86	78	80	64	80	63	80	64	66	66	63	77	71	77	73
Trimble County 2	51	64	58	83	61	80	72	78	79	82	73	69	76	77	78
Cane Run 7	N/A	N/A	N/A	80	85	89	87	81	61	52	82	83	75	60	55
Trimble CTs	12	4	10	11	15	14	15	13	9	7	13	15	12	7	7
Brown 6-7	8	3	14	13	2	0.8	0.7	0.3	0.4	0.0	5	6	5	3	3
Brown 5, 8-11	0.5	0.3	2	8	8	1.9	1.9	1.4	1.2	0.0	1.3	1.8	1.0	0.5	0.5
Paddy's Run 13	4	2	7	13	8	12	11	11	6	6	14	13	12	9	7
Bluegrass 3	N/A	N/A	N/A	8	4	7	9	10	N/A	N/A	3	4	3	N/A	N/A
Cane Run 11	0.2	0.2	0.0	0.2	0.2	0.1	0.1	0.0	0.0	0.1	0.2	0.0	0.1	0.1	0.0
Haefling 1-2	0.4	0.2	0.3	1.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Paddy's Run 11	0.2	0.0	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.1	0.1	0.3	0.1	0.1	0.1
Paddy's Run 12	0.2	0.0	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0
Zorn 1	0.5	0.2	0.1	0.8	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.0	0.0	0.0
Dix Dam	18	51	34	35	29	26	26	26	26	26	28	28	28	27	28
Ohio Falls	45	49	65	33	62	58	63	63	63	63	59	63	63	63	63
Brown Solar	N/A	N/A	N/A	N/A	20	17	17	17	17	17	22	22	22	22	22

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PPL companies

Unit Rank by Operating Cost

	2017		2018		2019		2020		2021	
	2016 Plan	2017 Plan	2016 Plan	2017 Plan	2016 Plan	2017 Plan	2016 Plan	2017 Plan	2016 Plan	2017 Plan
Brown 1	14	14	14	14	14	14	14	14	14	14
Brown 2	13	13	13	13	13	13	13	13	13	13
Brown 3	15	15	15	15	15	15	15	15	15	15
Cane Run 7	2	2	6	7	8	9	11	11	12	11
Ghent 1	9	8	9	8	9	8	8	8	8	8
Ghent 2	8	4	8	4	7	5	7	5	7	5
Ghent 3	11	11	11	11	11	11	10	10	10	10
Ghent 4	10	10	10	10	10	10	9	9	9	9
Mill Creek 1	3	6	3	5	2	3	2	3	2	3
Mill Creek 2	5	9	4	9	5	7	3	7	3	7
Mill Creek 3	6	5	5	6	4	4	4	6	4	4
Mill Creek 4	7	3	7	2	6	2	5	2	5	2
OVEC	12	12	12	12	12	12	12	12	11	12
Trimble County 1	4	7	2	3	3	6	6	4	6	6
Trimble County 2	1	1	1	1	1	1	1	1	1	1

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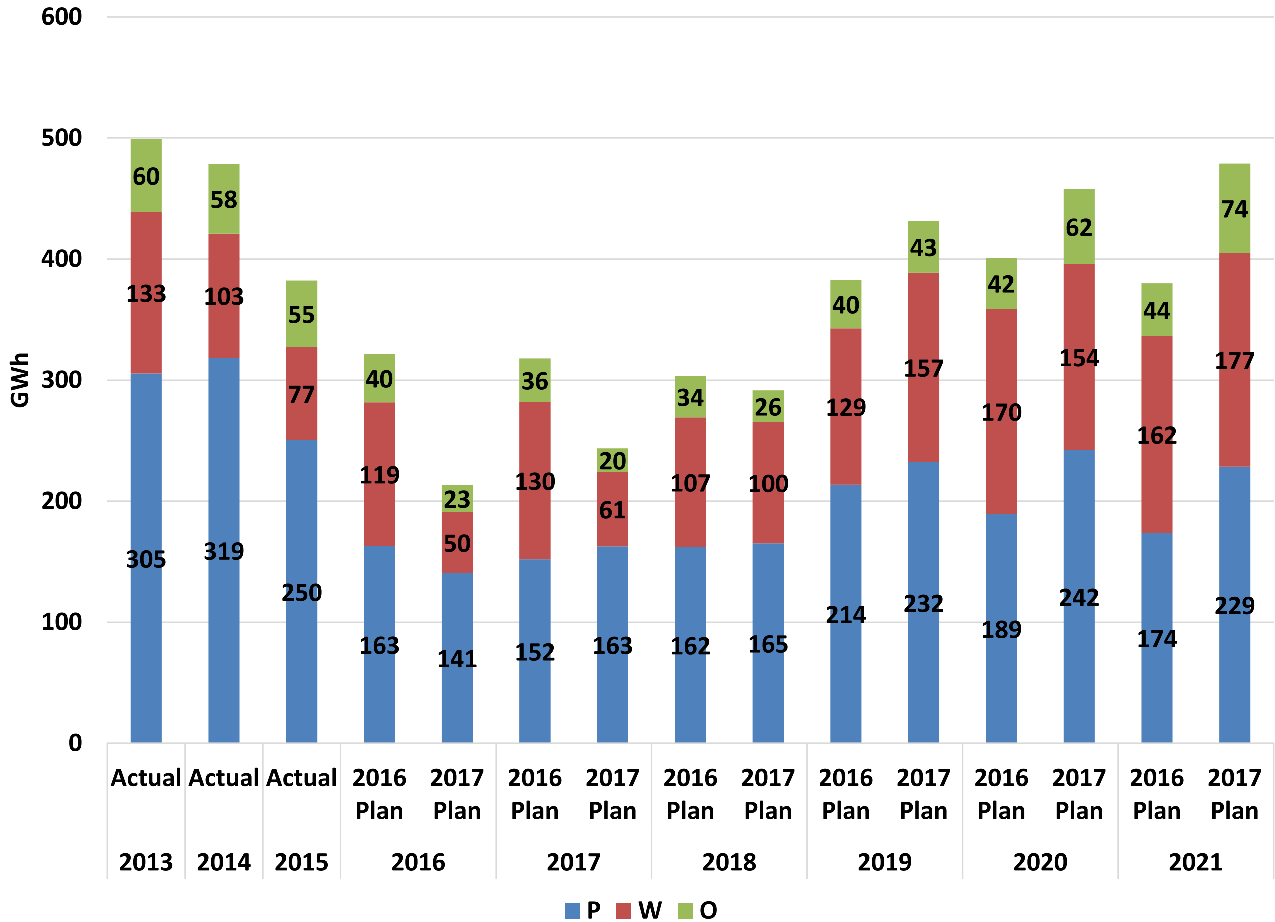
PPL companies

OSS volumes are lower in 2017-2018, and higher in 2019-2021



2017 Plan in 2016: 6 + 6

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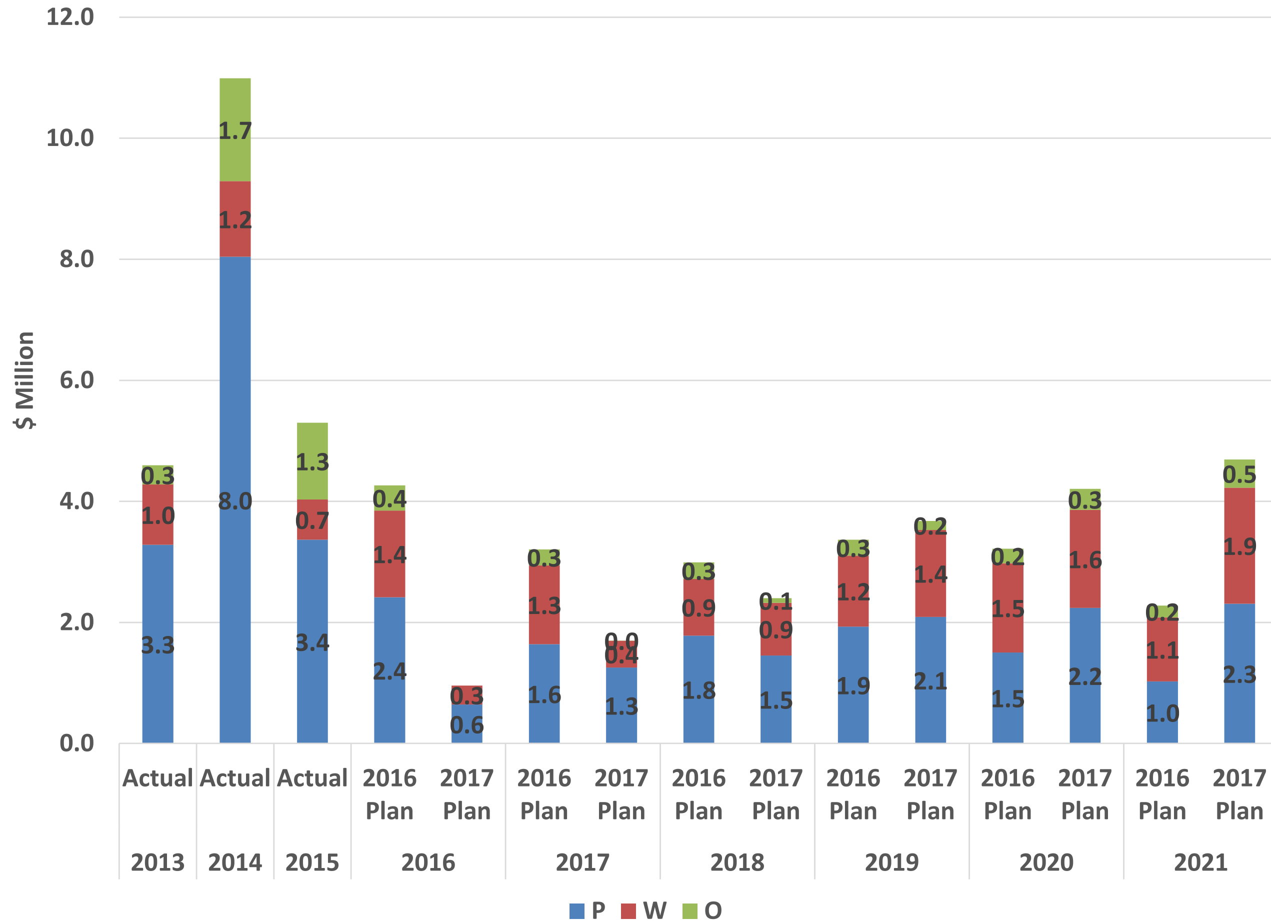
OSS Contribution by Peak Type



2017 Plan in 2016: 6 + 6

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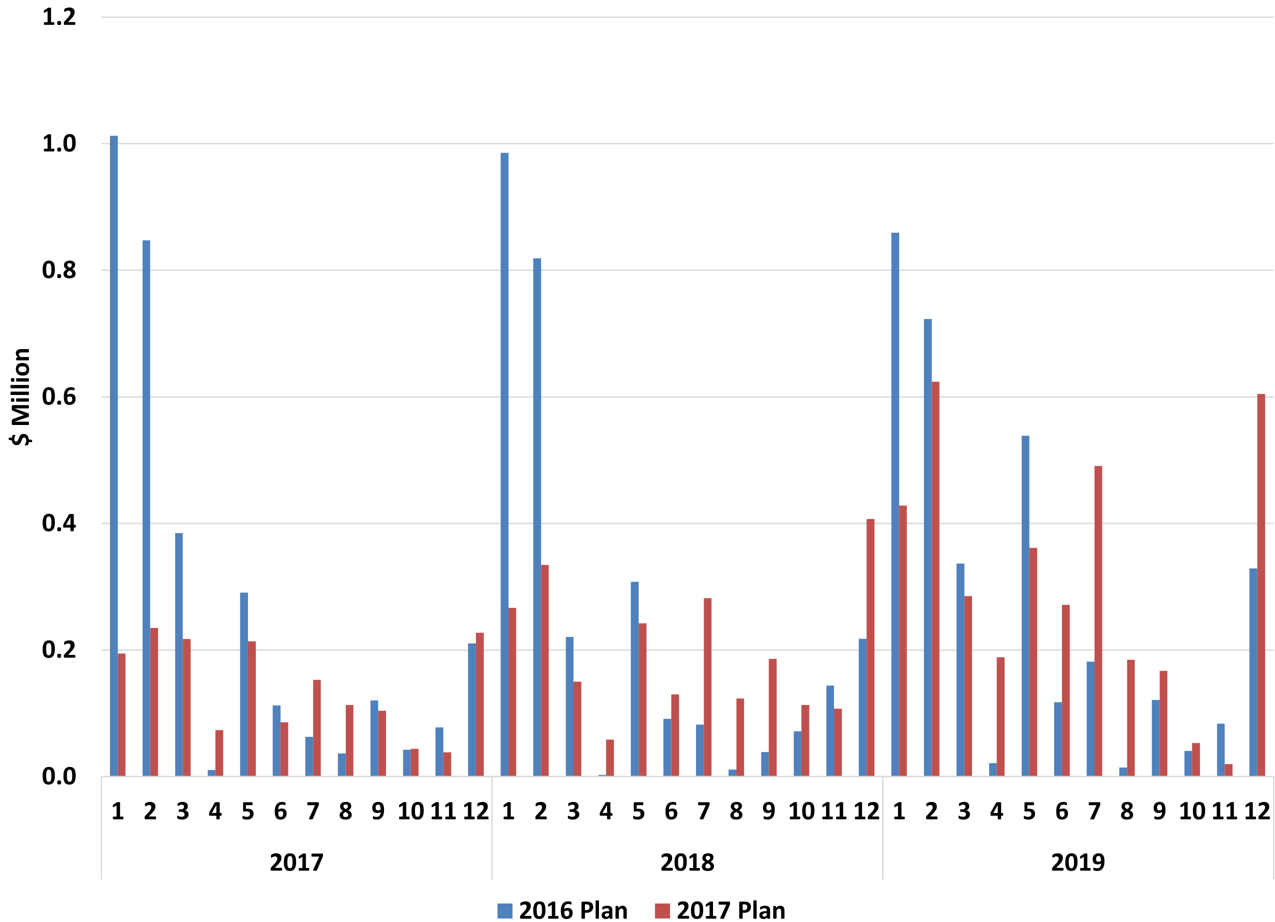
Removal of winter premium pricing results in OSS contribution more evenly spread between winter and summer



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LG&E KU
PPL companies

Variable O&M decreases in 2017 Plan

Total VO&M ($/MWh)	2017			2018			2019			2020		
	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff
Brown 1	2.11	2.83	0.73	2.17	2.89	0.72	2.37	2.95	0.58	2.35	3.01	0.66
Brown 2	2.42	2.14	(0.28)	2.51	2.18	(0.33)	2.69	2.22	(0.46)	2.69	2.27	(0.42)
Brown 3	3.10	3.04	(0.06)	3.20	3.08	(0.13)	3.38	3.17	(0.21)	3.41	3.21	(0.20)
Ghent 1	2.32	1.88	(0.44)	2.41	1.93	(0.48)	2.48	1.98	(0.50)	2.62	2.04	(0.57)
Ghent 2	2.02	1.11	(0.91)	2.07	1.13	(0.94)	2.19	1.16	(1.02)	2.31	1.20	(1.11)
Ghent 3	2.25	1.83	(0.41)	2.36	1.88	(0.48)	2.50	1.93	(0.57)	2.65	1.99	(0.66)
Ghent 4	2.48	1.90	(0.58)	2.60	1.88	(0.72)	2.60	2.00	(0.59)	2.88	2.06	(0.81)
Mill Creek 1	1.41	0.92	(0.50)	1.44	0.90	(0.54)	1.47	0.90	(0.58)	1.51	0.92	(0.59)
Mill Creek 2	1.44	1.14	(0.30)	1.46	1.14	(0.32)	1.49	1.13	(0.36)	1.53	1.17	(0.37)
Mill Creek 3	1.81	1.27	(0.54)	1.84	1.27	(0.58)	1.79	1.28	(0.52)	1.92	1.31	(0.60)
Mill Creek 4	1.80	1.17	(0.63)	1.83	1.26	(0.57)	1.86	1.18	(0.68)	1.90	1.22	(0.69)
Trimble 1	1.99	1.27	(0.73)	2.06	1.25	(0.80)	2.12	1.32	(0.79)	2.18	1.35	(0.83)
Trimble 2	1.76	1.38	(0.38)	1.82	1.43	(0.39)	1.87	1.45	(0.42)	1.93	1.49	(0.45)

FGD O&M decreases in 2017 Plan

FGD ($/MWh)	2017			2018			2019			2020		
	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff
Brown 1	0.74	0.63	(0.11)	0.75	0.64	(0.10)	0.77	0.66	(0.11)	0.78	0.67	(0.11)
Brown 2	0.69	0.58	(0.11)	0.70	0.59	(0.11)	0.72	0.61	(0.12)	0.74	0.62	(0.12)
Brown 3	0.72	1.23	0.51	0.73	1.23	0.50	0.75	1.28	0.53	0.77	1.27	0.51
Ghent 1	0.38	0.39	0.00	0.42	0.39	(0.03)	0.46	0.40	(0.06)	0.50	0.41	(0.10)
Ghent 2	0.84	0.35	(0.49)	0.88	0.35	(0.52)	0.94	0.36	(0.58)	1.01	0.37	(0.64)
Ghent 3	0.38	0.40	0.02	0.42	0.41	(0.01)	0.46	0.42	(0.04)	0.50	0.43	(0.08)
Ghent 4	0.38	0.41	0.02	0.42	0.41	(0.01)	0.46	0.42	(0.04)	0.50	0.43	(0.07)
Mill Creek 1	0.59	0.47	(0.12)	0.59	0.44	(0.15)	0.59	0.42	(0.18)	0.61	0.43	(0.18)
Mill Creek 2	0.59	0.46	(0.13)	0.58	0.44	(0.14)	0.60	0.42	(0.18)	0.61	0.43	(0.18)
Mill Creek 3	0.59	0.45	(0.14)	0.59	0.43	(0.16)	0.57	0.42	(0.15)	0.61	0.42	(0.19)
Mill Creek 4	0.58	0.44	(0.15)	0.58	0.42	(0.16)	0.59	0.41	(0.17)	0.61	0.42	(0.18)
Trimble 1	0.55	0.52	(0.03)	0.56	0.49	(0.07)	0.56	0.53	(0.03)	0.58	0.54	(0.04)
Trimble 2	0.43	0.44	0.01	0.43	0.46	0.02	0.44	0.45	0.01	0.45	0.45	0.01

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SCR O&M decreases in 2017 Plan

SCR ($/MWh)	2017 2016 Plan	2017 2017 Plan	2017 Diff	2018 2016 Plan	2018 2017 Plan	2018 Diff	2019 2016 Plan	2019 2017 Plan	2019 Diff	2020 2016 Plan	2020 2017 Plan	2020 Diff
Brown 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 3	0.49	0.37	(0.11)	0.50	0.38	(0.12)	0.50	0.39	(0.11)	0.50	0.40	(0.10)
Ghent 1	0.42	0.33	(0.09)	0.43	0.34	(0.09)	0.43	0.34	(0.09)	0.43	0.35	(0.08)
Ghent 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 3	0.42	0.28	(0.14)	0.43	0.29	(0.14)	0.43	0.29	(0.14)	0.43	0.30	(0.13)
Ghent 4	0.42	0.33	(0.09)	0.43	0.29	(0.14)	0.43	0.34	(0.09)	0.43	0.35	(0.08)
Mill Creek 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mill Creek 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mill Creek 3	0.45	0.38	(0.07)	0.46	0.39	(0.07)	0.44	0.40	(0.05)	0.46	0.41	(0.05)
Mill Creek 4	0.49	0.36	(0.13)	0.50	0.39	(0.11)	0.50	0.37	(0.13)	0.50	0.38	(0.12)
Trimble 1	0.26	0.23	(0.03)	0.26	0.22	(0.04)	0.26	0.23	(0.03)	0.26	0.23	(0.03)
Trimble 2	0.24	0.19	(0.05)	0.24	0.19	(0.05)	0.24	0.19	(0.05)	0.24	0.20	(0.04)

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SO_3 O&M decreases for Ghent 4 and Trimble County 1 & 2

SO3 ($/MWh)	2017 2016 Plan	2017 2017 Plan	2017 Diff	2018 2016 Plan	2018 2017 Plan	2018 Diff	2019 2016 Plan	2019 2017 Plan	2019 Diff	2020 2016 Plan	2020 2017 Plan	2020 Diff
Brown 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 3	0.26	0.25	(0.01)	0.27	0.26	(0.01)	0.28	0.27	(0.01)	0.29	0.28	(0.01)
Ghent 1	0.72	0.75	0.03	0.74	0.78	0.04	0.76	0.81	0.05	0.80	0.84	0.04
Ghent 2	0.33	0.35	0.02	0.34	0.37	0.03	0.35	0.38	0.03	0.37	0.40	0.03
Ghent 3	0.69	0.74	0.05	0.72	0.77	0.05	0.77	0.80	0.03	0.82	0.83	0.01
Ghent 4	0.92	0.75	(0.17)	0.96	0.77	(0.19)	0.94	0.81	(0.13)	1.07	0.84	(0.23)
Mill Creek 1	0.27	0.27	0.00	0.27	0.28	0.01	0.28	0.29	0.01	0.28	0.30	0.02
Mill Creek 2	0.27	0.27	0.00	0.27	0.28	0.01	0.28	0.29	0.02	0.29	0.31	0.02
Mill Creek 3	0.22	0.25	0.03	0.22	0.26	0.04	0.21	0.27	0.05	0.23	0.28	0.05
Mill Creek 4	0.18	0.22	0.04	0.18	0.26	0.07	0.19	0.24	0.05	0.19	0.24	0.06
Trimble 1	0.87	0.52	(0.35)	0.90	0.54	(0.36)	0.93	0.56	(0.37)	0.97	0.58	(0.39)
Trimble 2	0.70	0.46	(0.24)	0.73	0.48	(0.25)	0.75	0.50	(0.26)	0.78	0.52	(0.27)

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Mercury O&M decreases largely attributed to increased knowledge and experience with baghouse operation; BR1 increase is related to more accurate allocation of costs at the station

Mercury	2017			2018			2019			2020		
($/MWh)	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff	2016 Plan	2017 Plan	Diff
Brown 1	1.37	2.20	0.83	1.43	2.25	0.82	1.60	2.29	0.69	1.56	2.34	0.77
Brown 2	1.72	1.55	(0.17)	1.81	1.59	(0.22)	1.96	1.62	(0.35)	1.95	1.65	(0.30)
Brown 3	1.63	1.18	(0.45)	1.71	1.20	(0.50)	1.85	1.23	(0.62)	1.86	1.25	(0.60)
Ghent 1	0.80	0.41	(0.38)	0.82	0.42	(0.40)	0.83	0.43	(0.40)	0.88	0.44	(0.44)
Ghent 2	0.84	0.40	(0.44)	0.86	0.41	(0.45)	0.89	0.42	(0.47)	0.93	0.43	(0.50)
Ghent 3	0.76	0.41	(0.35)	0.79	0.42	(0.38)	0.84	0.42	(0.42)	0.90	0.43	(0.46)
Ghent 4	0.76	0.41	(0.35)	0.79	0.42	(0.38)	0.77	0.43	(0.34)	0.87	0.44	(0.44)
Mill Creek 1	0.56	0.18	(0.38)	0.58	0.18	(0.40)	0.60	0.19	(0.41)	0.62	0.19	(0.43)
Mill Creek 2	0.58	0.40	(0.17)	0.60	0.41	(0.19)	0.62	0.42	(0.20)	0.64	0.43	(0.21)
Mill Creek 3	0.55	0.19	(0.36)	0.58	0.20	(0.38)	0.57	0.20	(0.37)	0.62	0.20	(0.41)
Mill Creek 4	0.55	0.16	(0.39)	0.57	0.20	(0.37)	0.59	0.16	(0.42)	0.61	0.17	(0.44)
Trimble 1	0.32	0.00	(0.32)	0.34	0.00	(0.34)	0.36	0.00	(0.36)	0.37	0.00	(0.37)
Trimble 2	0.40	0.30	(0.10)	0.42	0.31	(0.11)	0.44	0.31	(0.13)	0.46	0.32	(0.14)

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CCR at Mill Creek and Trimble County

- Mill Creek
  - *Current beneficial use contracts of 380K tons/year*
  - *Proposed contracts with temporary dewatering system allow for additional 450K tons/year*
  - *Proposed contracts will extend Phase I landfill capacity from 2026 to 2029; continuation of these contracts in the long term would extend to 2036*

- Trimble County
  - *Current beneficial use contracts of 200K tons/year*
  - *Expect new landfill permitting complete in 2016 and in service by 2019*

Maintenance changes largely attributed to Mill Creek and Trimble County 2

Maintenance-Weeks

	2017 Plan					2016 Plan					2017 Plan - 2016 Plan				
	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021
Brown 1	1	3	1	3	1	1	3	1	3	1	-	-	-	-	-
Brown 2	2	8	1	2	1	2	8	1	2	1	-	-	-	-	-
Brown 3	3	3	3	8	1	1	3	3	8	1	2	-	-	-	-
Ghent 1	3	4	3	4	4	3	5	3	3	3	-	(1)	-	1	1
Ghent 2	4	3	8	4	4	4	3	9	3	3	-	-	(1)	1	1
Ghent 3	3	8	4	3	3	3	8	5	3	3	-	-	(1)	-	-
Ghent 4	3	4	4	4	8	3	4	3	3	8	-	-	1	1	-
Mill Creek 1	4	1	8	1	4	4	1	4	1	8	-	-	4	-	(4)
Mill Creek 2	3	8	1	4	1	1	4	1	8	1	2	4	-	(4)	-
Mill Creek 3	5	1	8	1	4	5	1	8	1	4	-	-	-	-	-
Mill Creek 4	1	8	1	4	1	1	4	1	4	1	-	4	-	-	-
Trimble County 1	10	2	5	2	5	9	2	5	2	5	1	-	-	-	-
Trimble County 2	6	9	5	5	5	3	9	5	5	3	3	-	-	-	2
Cane Run 7	3	2	5	2	2	2	2	4	4	2	1	-	1	(2)	-
Totals	**51**	**64**	**57**	**47**	**44**	**42**	**57**	**53**	**50**	**44**	**9**	**7**	**4**	**(3)**	**-**
MW-Maint Wks*	**23,163**	**27,685**	**26,630**	**21,466**	**20,950**	**19,082**	**25,055**	**25,252**	**22,584**	**20,108**	**4,082**	**2,630**	**1,378**	**(1,118)**	**842**

*Coal + CR7 Only

Notes:

Acceleration of turbine overhauls for Mill Creek 1 and 2 (from 2021 to 2019, and 2020 to 2018, respectively) and addition of outage weeks at Mill Creek 4 in 2018 are to accommodate conversion of bottom ash systems from wet to dry.

Increases at Trimble County 2 in 2017 and 2021 are related to waterwall repair.

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Modeled EFOR assumptions reflect a decrease for Cane Run 7 and an increase for Trimble County 2

EFOR %	2017 Plan	2016 Plan	2017 Plan - 2016 Plan
Brown 1	5.6	5.6	0.0
Brown 2	5.6	5.6	0.0
Brown 3	5.6	5.6	0.0
Ghent 1	5.6	5.6	0.0
Ghent 2	5.6	5.6	0.0
Ghent 3	5.6	5.6	0.0
Ghent 4	5.6	5.6	0.0
Mill Creek 1	5.6	5.6	0.0
Mill Creek 2	5.6	5.6	0.0
Mill Creek 3	5.6	5.6	0.0
Mill Creek 4	5.6	5.6	0.0
Trimble County 1	5.6	5.6	0.0
Trimble County 2	7.6	6.0	1.6
Cane Run 7	3.0	5.0	(2.0)
Total EFOR	**5.5**	**5.6**	**(0.1)**

*Cane Run 7's MOR adjusted to 5.9% to reflect expected performance (previously not modeled)

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Minor adjustments to heat rates; rates reflective of post-baghouse installation data where available

	2016 Plan	2017 Plan	Difference (2017 Plan vs 2016 Plan)	Percent Change
BR1	10,380	10,380	0	0.0%
BR2	10,280	10,290	10	0.1%
BR3	10,850	10,850	0	0.0%
GH1	10,800	10,600	-200	-1.9%
GH2	10,600	10,410	-190	-1.8%
GH3	11,030	11,030	0	0.0%
GH4	11,000	10,820	-180	-1.6%
MC1	10,430	10,430	0	0.0%
MC2	10,600	10,720	120	1.1%
MC3	10,530	10,530	0	0.0%
MC4	10,730	10,490	-240	-2.2%
TC1	10,570	10,710	140	1.3%
TC2	9,230	9,230	0	0.0%
CR7	6,830	6,830	0	0.0%

Notes:
Values shown represent summer net heat rates at maximum load.
Heat rate changes reflect calibration of forecasted fuel burn to actual fuel burn.

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2017 Fuel Cost Comparison – Annual Averages

Fuel Expense (¢/mmBTU)				Delta	
		2017 Plan 2017	2016 Plan 2017	2017 Plan 2017 - 2016 Plan 2017	% Change
COAL	BR	284	302	(18)	-6%
	GH	205	233	(28)	-12%
	MC	204	228	(24)	-11%
	TC HS	204	226	(22)	-10%
	TC PRB	227	239	(12)	-5%
GAS	Gas BR	320	350	(30)	-9%
	Gas TC	320	350	(30)	-9%
	Gas CR7	318	350	(32)	-9%
	Gas PR	320	355	(35)	-10%
	Gas Haef	910	940	(30)	-3%
OIL	Oil	1,198	1,718	(521)	-30%

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LG&E KU PPL companies

2018 Fuel Cost Comparison – Annual Averages

Fuel Expense (¢/mmBTU)				Delta	
		2017 Plan 2018	2016 Plan 2018	2017 Plan 2018 - 2016 Plan 2018	% Change
COAL	BR	277	299	(23)	-8%
	GH	200	237	(38)	-16%
	MC	199	231	(32)	-14%
	TC HS	195	229	(34)	-15%
	TC PRB	230	265	(35)	-13%
GAS	Gas BR	323	371	(48)	-13%
	Gas TC	323	371	(48)	-13%
	Gas CR7	321	371	(50)	-14%
	Gas PR	323	376	(53)	-14%
	Gas Haef	913	961	(48)	-5%
OIL	Oil	1,345	1,976	(631)	-32%

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2019 Fuel Cost Comparison – Annual Averages

Fuel Expense (¢/mmBTU)				Delta	
		2017 Plan 2019	2016 Plan 2019	2017 Plan 2019 - 2016 Plan 2019	% Change
COAL	BR	269	300	(30)	-10%
	GH	203	237	(34)	-14%
	MC	201	229	(28)	-12%
	TC HS	199	230	(31)	-13%
	TC PRB	233	277	(44)	-16%
GAS	Gas BR	340	397	(57)	-14%
	Gas TC	340	397	(57)	-14%
	Gas CR7	338	397	(59)	-15%
	Gas PR	340	401	(62)	-15%
	Gas Haef	930	987	(57)	-6%
OIL	Oil	1,699	2,219	(520)	-23%

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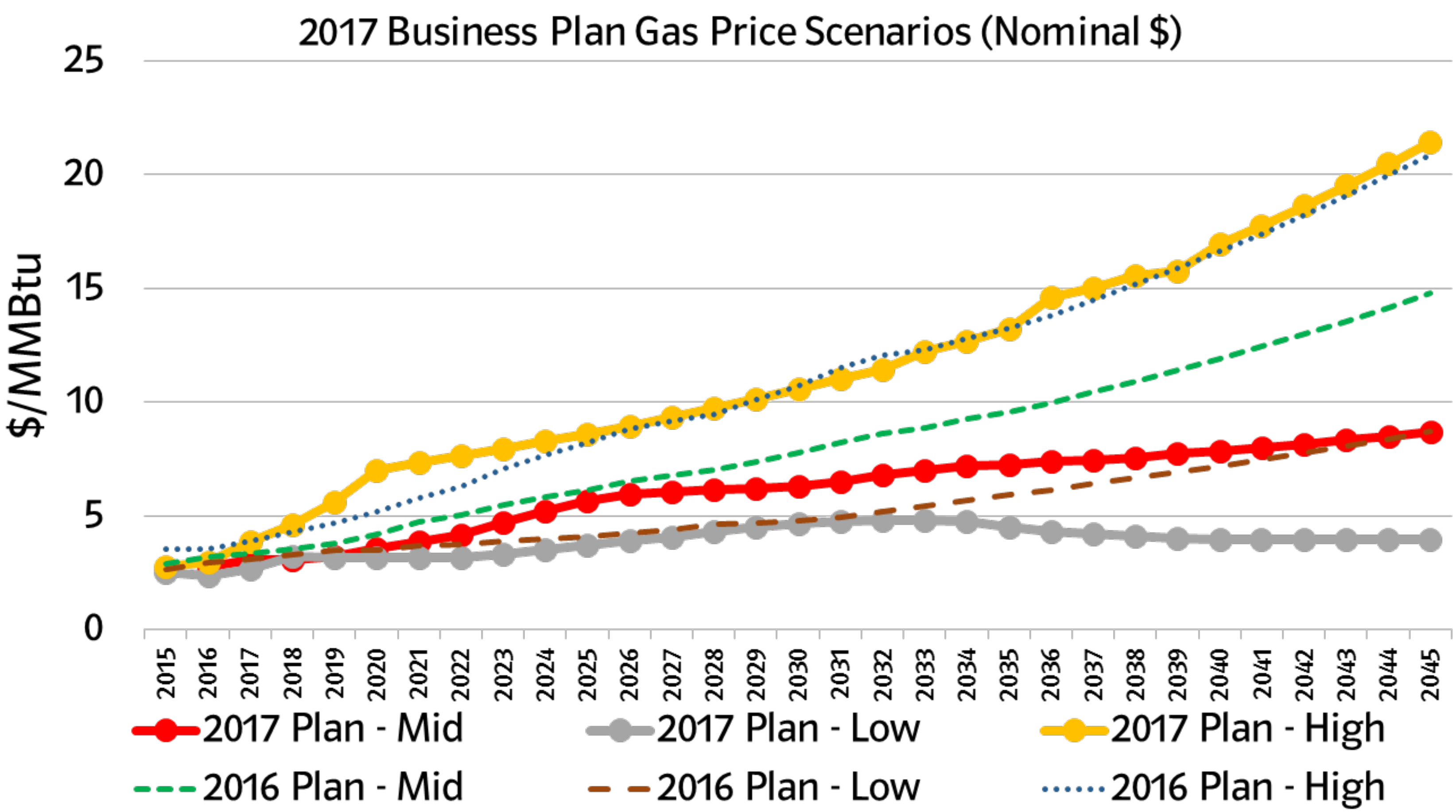
High/Low natural gas curves reflect wide range of prices



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Market electricity prices are consistently lower in 2017 Plan

Market Price Comparison

Market Price $/MWh	2017 Plan Peak	2017 Plan Off-Peak	2017 Plan Weekend	2016 Plan Peak	2016 Plan Off-Peak	2016 Plan Weekend	2017 Plan - 2016 Plan Peak	2017 Plan - 2016 Plan Off-Peak	2017 Plan - 2016 Plan Weekend
Jan-17	36.11	29.37	28.57	58.38	42.85	47.53	-22.27	-13.48	-18.95
Feb-17	35.58	30.33	30.92	50.69	40.25	43.72	-15.11	-9.92	-12.80
Mar-17	36.00	28.22	31.37	42.33	32.35	38.67	-6.32	-4.13	-7.30
Apr-17	33.58	22.35	26.06	36.39	27.18	32.88	-2.81	-4.83	-6.82
May-17	33.14	19.69	30.10	37.87	22.61	32.84	-4.73	-2.92	-2.73
Jun-17	36.11	17.22	30.71	40.31	21.87	36.55	-4.20	-4.65	-5.85
Jul-17	43.77	19.69	32.00	50.09	23.48	36.20	-6.32	-3.79	-4.20
Aug-17	41.21	19.23	30.55	43.44	24.21	35.11	-2.23	-4.98	-4.56
Sep-17	32.35	18.22	26.52	35.12	22.57	31.93	-2.77	-4.35	-5.41
Oct-17	30.97	22.11	25.49	34.98	25.75	29.76	-4.01	-3.64	-4.26
Nov-17	31.95	22.72	24.27	35.71	26.53	29.35	-3.76	-3.81	-5.08
Dec-17	35.25	24.23	28.23	38.02	29.01	33.90	-2.77	-4.79	-5.68
Jan-18	37.46	30.97	31.61	56.29	41.96	46.87	-18.83	-10.99	-15.26
Feb-18	36.86	31.21	33.23	50.04	40.05	43.82	-13.19	-8.84	-10.59
Mar-18	34.96	28.37	31.34	42.31	32.87	39.69	-7.35	-4.50	-8.34
Apr-18	33.34	23.87	27.59	37.29	28.62	34.79	-3.94	-4.75	-7.20
May-18	32.76	22.17	30.70	38.54	24.77	34.43	-5.78	-2.60	-3.73
Jun-18	36.63	20.46	32.03	41.26	24.37	38.19	-4.63	-3.91	-6.17
Jul-18	45.27	23.07	34.86	52.04	26.05	38.10	-6.77	-2.98	-3.24
Aug-18	41.74	22.44	32.90	44.30	26.51	36.28	-2.55	-4.07	-3.38
Sep-18	32.77	20.85	28.02	36.07	24.60	33.84	-3.31	-3.75	-5.81
Oct-18	31.50	23.71	26.91	36.61	27.70	32.44	-5.11	-3.99	-5.54
Nov-18	32.40	24.59	26.52	37.26	28.58	32.72	-4.86	-3.99	-6.19
Dec-18	35.65	26.61	30.35	39.71	30.75	36.39	-4.06	-4.13	-6.04

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Peak Load and Energy Comparison

Peak Delta (2017 Plan - 2016 Plan)

MW	2017	2018	2019	2020	2021
Jan	55	67	(4)	129	62
Feb	4	(54)	(46)	(199)	(61)
Mar	(120)	(151)	(137)	(77)	(127)
Apr	(335)	(91)	(337)	(119)	(97)
May	72	75	57	3	76
Jun	94	85	114	50	61
Jul	(83)	(95)	(21)	(41)	(69)
Aug	(182)	(199)	(192)	(207)	(253)
Sep	(408)	(365)	(350)	(428)	(375)
Oct	(36)	(253)	(0)	(55)	(25)
Nov	95	45	86	122	24
Dec	189	204	234	109	174
Peak	**(182)**	**(199)**	**(192)**	**(207)**	**(253)**

Energy Delta (2017 Plan - 2016 Plan)

GWh	2017	2018	2019	2020	2021
Jan	(8)	(14)	(15)	(20)	(41)
Feb	(39)	(45)	(58)	(73)	(84)
Mar	(93)	(104)	(106)	(110)	(111)
Apr	(107)	(119)	(119)	(136)	(148)
May	(20)	(20)	(39)	(43)	(38)
Jun	(20)	(29)	(35)	(46)	(56)
Jul	(51)	(61)	(66)	(78)	(87)
Aug	(81)	(92)	(96)	(109)	(120)
Sep	(113)	(121)	(133)	(142)	(146)
Oct	(90)	(99)	(100)	(110)	(114)
Nov	(16)	(23)	(11)	(21)	(19)
Dec	27	9	(11)	(32)	(17)
Total	**(609)**	**(718)**	**(789)**	**(919)**	**(980)**

PPL companies

Power Generation

2017 Business Plan

September 2016






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Plan Highlights

- Major investment and integration of environmental compliance – Coal Combustion Residuals (CCR), pond closures and Effluent water Limit Guidelines (ELG)
- Generation forecast assumes continued trend of high Natural Gas Combined Cycle (NGCC) production levels based on current projections for gas prices in first three years of the plan; NGCC production levels taper off later in the plan as gas prices increase
- Increased resource needs to meet and maintain compliance with incremental regulatory requirements – begin staffing to meet ELG in 2018
- There are no planned coal plant retirements for the plan period

LG&E KU
PPL companies

Major Assumptions

1. Regulatory

The 2017 Business Plan (2017 BP) covers 2017-2021 completely, and in the case of Power Generation and Project Engineering, known projects that extend to 2026.

1.1 The State of Kentucky remains regulated throughout the plan period and the Environmental Cost Recovery (ECR) and Fuel Adjustment Clause (FAC) remain in place.
1.2 Target Reserve Margin Range of 16% - 21%.
1.3 Reserve sharing under the TVA Reserve Sharing Agreement is 245 MW's.
1.4 LG&E and KU remain committed to burning less expensive, higher sulfur fuels, which continues to trend toward higher chlorine fuels.
1.5 Of the twelve municipal utilities served by KU, nine provided termination notices. Combined with the departure of Benham, this will be a reduction of 325 MW by May, 2019.

2. Proposed or Expected New Environmental Regulations for Air and Water

2.1 The Cross State Air Pollution Rules (CSAPR) were reinstated with Phase I in 2015-2016 and Phase II in 2017. EPA is now referring to it as "Transport Rule".
- The US EPA has provided accounts with Transport Rule allocations through 2016.
- LKE System Transport Rule allocations at similar levels as prior CAIR (Clean Air Interstate Rule) allocations.
- A penalty of allowances surrendered by each utility with NOX emissions over 18% of Annual Allocation and 21% of Ozone Season Allocation (Assurance Levels) IF the State exceeds its "assurance level".
  - *Penalty of 2 allowances for every 1 ton of emissions (2:1) over the "assurance levels"*
- "CSAPR Update Rule" (CSAPR II) was proposed by EPA December 3, 2015
  - *Keeps existing CSAPR rules except banking*
  - *Allows banking including existing CSAPR bank*
  - *Various levels of restrictions proposed on use of banked 2015-2016 allowances (i.e. 2:1, 4:1)*
  - *Replaces existing CSAPR Ozone Season allocations beginning 2017 for Company by (~ 30% reduction from existing allocations)*

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Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water (Cont.)</u>

2.2 The final National Ambient Air Quality Standards (NAAQS) rules have been issued, with one hour standards in place for NO_x and SO_2. The final attainment designations for the short term NO_x standard have been delayed for up to three years due to inadequate monitoring. An area near Mill Creek has been designated non-attainment based on the new short term SO_2 standards. Compliance requirements must be in place by October 2018.

- **Based on attainment modeling, LG&E has proposed a rolling 30-day mass standard (tons/30days) of emissions in total from units 1-4 based on 0.17 lbs SO2/mmBtu with each unit at maximum load. during the entire 30-day period (MC units currently well below this limit with the new Wet FGD's).**
- **APCD has indicated they are in favor of the proposed standard.**
- **APCD still working with other contributing entity near Mill Creek to establish their limit.**

2.3 The EPA issued its revised rule on PM NAAQS on December 14, 2012.

- **The 1997 annual Particular Matter standard for $(PM)_{2.5}$ of 15 ug/M^3 was lowered to 12ug/M^3.**
  - **Initial designations of 1997 NAAQS placed Jefferson and Bullitt as non-attainment.**
  - **A re-designation request to "Attainment/Unclassifiable" of 1997 NAAQS is in the works by APCD and KDAQ.**
  - **Jefferson County designation for 2012 NAAQS has been revised to "unclassifiable / attainment" until further monitoring data is available (by end of 2016).**
  - **The recent modifications at Gallagher Station, the shutting down of Cane Run 4, 5, and 6, and the baghouses, scrubbers, and dry sorbent injection systems at Mill Creek should establish attainment mitigate future concerns in Jefferson County.**

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.4 The EPA issued a final revision of the 8-hour Ozone NAAQS in October of 2015

- 2008 NAAQS = 75 ppb (remains in effect); Revised 2015 NAAQS = 70 ppb
- For 2008 NAAQS
  - Northern Ky / Cincinnati area “Marginal Non-Attainment” ; remainder of Ky is “Unclassifiable / Attainment”
- For 2015 NAAQS
  - Designation to be based on 2014-2016 data
  - Initial data (2013 – 2015) indicates “Attainment”
  - Likely Case: Additional improvements expected due to coal unit shutdowns and additional SO_2 and PM controls sufficiently mitigates ground level ozone
  - Worst Case: Local Non-Attainment driving need for SCRs on coal-fired units that significantly contribute to non-attainment (Mill Creek Units 1 & 2 and Ghent 2 do not have SCR’s, and they are not included in 2017 BP).
  - The SIP revision process will target attainment by 2021 – 2037 depending on level of non-attainment.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.5 Final Clean Power Plan – "Existing Source Performance Standards" (ESPS) regulation was published in Federal Register on October 23, 2015

- ***Final rule assumed performance based on "Regional" capability***
- ***Changed Kentucky's proposed interim limit on CO2 emissions from 1,844 to 1,509 lb CO2/MWh(net) beginning 2022 (proposed rule began interim compliance in 2020)***
- ***Changed Kentucky's proposed final (2030) limit on CO2 emissions from 1,763 to 1,286 lb CO2/MWh(net)***
- ***Mass based targets were defined for each state in the final rule.***
- ***States can propose either rate or mass-based plans***
- ***Trading program and banking allowed with mass cap***
- ***Applicable to "existing sources" that commenced construction prior to January 7, 2014 (when NAPS for GHG emissions was proposed); however, limits utilization of new sources as well***
- ***Designed by EPA to shift generation away from combustion sources to renewable sources***
- ***Final rule contained concepts and reductions not included in proposed rule***
- ***Highly litigated. Supreme Court stayed the rule on February 9, 2016 pending determination by US Court of Appeals for DC Circuit Court***

NOTE - THE RESULT OF LITIGATION MAY ALTER SOME OR ALL OF THE ABOVE COMPONENTS

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Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.6 Effluent water guideline draft proposal was issued April 19, 2013, with the final rule issued September 30, 2015.

- **The ELG rule requires implementation as soon as possible after 2018 but must be implemented no later than December 2023. A mercury discharge limit of 51 ppt for all four remaining coal-fired stations as part of new state KPDES permit requirements will likely require LKE to be ahead of the EPA timeline specifically for mercury.**
- **The ELG Projects estimated in-service dates are 2021 for Mill Creek and Trimble County, and 2022 for Brown and Ghent.**

Major Assumptions

3. Expansion/Capacity

3.1 No capacity additions or retirements are in the plan through 2021.

3.2 Reserve margin purchases through use of Bluegrass 3 are 165 MW between May 1, 2015 and April 30, 2019.

- Bluegrass 3 is available for dispatch the same as the LKE owned CT's.

3.3 The two Ohio Falls units still to be rehabilitated (the other six are complete) continue to have the following scheduled mechanical completion dates.

- Unit 4 (Fall, 2016).
- Unit 8 (Fall, 2017).

3.4 Black start additions (for system restoration purposes only) will take place in 2017.

- Trimble County Site October, 2017 in-service.
- Cane Run Site October, 2017 in-service.
- Neither unit will be counted as generation capacity.

Major Assumptions

4. Coal Combustion Residuals (CCR's)

4.1 EPA finalized the CCR rule on December 19, 2014 (published in the Federal Register on April 17, 2015).

- Maintained the non-hazardous designation of CCRs.
- Does not require the immediate closure of unlined CCR impoundments but instead lists several criteria that must be met to continue operation. Some of those criteria include:
  - Siting requirements (wetlands, karst, water table …)
  - Dam safety factors
  - Groundwater monitoring and statistical evaluation
  - Flood control system
- Requires development of:
  - Emergency action plans
  - Fugitive dust control plan
  - Inspection programs
  - Public available internet site for placement of operating data
- Current landfill construction projects meet the requirements of the rule.
- Expect unlined CCR ponds to stop receiving waste and start closure process in 2019 (because of groundwater criteria).
- Congress is working on a separate (but similar) bi-partisan CCR bill which would usurp the EPA rule if passed through both chambers and signed by President (still a long shot).

Major Assumptions

4. Coal Combustion Residuals (CCR's) (Cont.)

- Pond Closures under the CCR Pond Closure Rule by year are as follows:
  - 2016: Cane Run Storm Water Pond, Cane Run Clearwell Pond.
  - 2017: Mill Creek Runoff Pond and Emergency Pond.
  - 2018: Mill Creek Clearwell Pond and Dead Storage Pond.
  - 2019: Green River Main Ash Pond, ATB2 and SO2 Pond, Ghent Reclaim, Ghent Secondary Pond, Pineville Ash Pond, and Tyrone Ash Pond.
  - 2020: Ghent Gypsum Stack and Brown Aux Pond.
  - 2021: Mill Creek Ash Pond.
  - 2022: Ghent ATB #2, Trimble County BAP and GSP and Ghent ATB #1.
  - In the year that each pond is closed, it will also be retired from the property accounting perspective.
  - Monitoring wells are added for all ponds and landfills affected by the CCR Rule.

Major Assumptions

4. Coal Combustion Residuals (CCR) (Cont.)

4.2 Trimble County Landfill and Transport.

- The projected in-service date for the transport and treatment system is July, 2018.
- The projected in-service date for Landfill Phase 1A is Q3, 2018.
  - The DWM landfill permit is anticipated to be December, 2016.
  - Litigation of permit is likely; however, the construction spend will continue as planned unless court issues a stay of the permit.
  - Construction period of 1.5 years.

4.3 A new Mill Creek landfill will be in-service by December 31, 2022, with a new gypsum dewatering facility in place by December 31, 2018, to support increased off-site beneficial reuse marketing of gypsum.

4.4 The Cane Run Landfill will be covered in 2016 and closed in Q2, 2017.

4.5 The Cane Run Ash Pond Cap & Closure project will be completed in Q2, 2017.

4.6 All CCR Capital Projects use an annual escalation rate of 4.0%.

4.7 The pond closure projects assume that existing CCR materials from each plant can be beneficially used to fill in each pond, similar to Cane Run. If that is not allowed by rule, the estimated cost of having to instead procure top soil and clay is an additional $180M.

Major Assumptions

5. Operational and Other

5.1 The next turbine overhauls by unit are as follows:

- **2016 : None scheduled.**
- **2017: Trimble 1.**
- **2018: Ghent 3, Mill Creek 2, Trimble 2 (HP rotor and IP rotors), Brown 2.**
- **2019: Ghent 2, Mill Creek 1, Mill Creek 3, Trimble 2 (both LP rotors).**
- **2020: Brown 3, Trimble 2 (Generator).**
- **2021: Ghent 4.**

Major Assumptions

5. Operational and Other (Cont.)

5.2 Targets for percentage hedged of the minimum projected coal requirement in the 2017 Business Plan (by the end of 2016) are as follows:

- Year | Coal

Year		Coal
1	2017	95%-100%.
2	2018	80%-90%.
3	2019	40%-90%.
4	2020	30%-70%.
5	2021	10%-50%.
6	2022	0%-30%.

- Targets for CR7 natural gas are the minimum projected CR7 requirement in the 2017 BP (by the end of 2016) are as follows:
  - *2017* *10-50%*
  - *2018* *0-30%*
  - *2019* *0-10%*

5.3 Based on forecasted coal prices, the competition between coal units and CR7 occurs for natural gas prices between \$3.50 and \$5.00 per MMBTU. CR7 natural gas usage varies from a minimum of 15BCF to a maximum of 36 BCF. This can change coal burn by 1.4 million tons per year.

Major Assumptions

5. Operational and Other (Cont.)

5.4 Combustion turbine outages in the plan:

- Dollars are split between O&M and capital based on the estimated scope of work that is reconditioning (expense – approximately 10%) vs. new parts (capital – approximately 90%).
- For the second set of Trimble CT hot gas path inspections, the schedule is one unit in 2016, two units in 2017, two units in 2018, and one unit in 2019.
- This order may change in conjunction with the majors and rotor inspections during this plan. Currently, the majors and rotor inspections are just outside of the 5-year planning window,
- Brown C inspections by unit are as follows:
  - Unit 5 in 2017.
  - Unit 6 in 2018.
  - Unit 11 in 2018.
  - Unit 7 in 2020.
  - Unit 8 in 2020.
  - Unit 9 in 2024.
  - Unit 10 in 2026.
- The expiration date for the Brown 6 and 7 Long-Term Services Agreements (LTSA) is October 1, 2016 based on the 13-year criteria.
- The CT component outages for Cane Run 7 are a Combustion Inspection May, 2017, Hot Gas Path Inspection (HGPI) October, 2019, Combustion Inspection March, 2022, and a major in 2023 (HGPI and turbine overhaul).
  - Cane Run 7 CT’s are covered under a signed LTSA.
  - The turbine/generator overhaul will be a generator minor in 2017, a turbine minor in 2018, a turbine/generator medium in 2020, a turbine/generator minor in 2023, and a major outside of the 10-year window.

Major Assumptions

5. Operational and Other (Cont.)

5.5 Complete demolition of Paddy's Run Coal Plant will take place 2016-2017.

5.6 Complete demolition of Cane Run Coal Plant will be 2017-2019.

5.7 Complete demolition of Green River will be 2017-2019.

5.8 Complete demolition of Pineville Station will be 2018-2019.

5.9 Complete demolition of Tyrone Station will be 2018-2019.

5.10 Complete demolition of Canal Station will be 2021-2022.

5.11 The prosym run dated August 10, 2016 is the official generation forecast for the 2017 Business Plan.

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only							
Company Labor	86,442	80,690	82,886	84,257	85,956	88,603	90,834
Resident Contractors	21,990	21,454	21,341	22,080	22,900	23,480	24,017
Maintenance	70,691	55,084	53,555	58,631	60,572	63,039	59,902
Outages	30,579	27,089	31,032	41,826	49,152	37,675	38,923
Green River Reg asset non labor	(2,334)	2,583	1,996	1,409	470	-	-
Operations	15,368	13,255	14,165	14,185	14,936	15,397	15,920
Total O&M Expense	222,737	200,155	204,976	222,388	233,985	228,194	229,596

PPL companies

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	205,177	221,934	230,023	236,278	233,936
Drivers:					
Move MC2 turbine outage two years		4,060		(4,060)	
Move MC1 turbine outage two years			4,180		(4,180)
Cane Run 7 decreased costs		(3,400)		(3,800)	
Fund Brown landfill bond costs	(148)	(156)	(164)	(172)	(180)
Changes in Maintenance and Operations expense	(53)	(50)	(53)	(52)	20
Current Plan	204,976	222,388	233,985	228,194	229,596
Variance - Fav (Unfav)	**201**	**(454)**	**(3,963)**	**8,084**	**4,340**

2015-2021 Margin Expenses / Cost of Sales Mechanism Recoverable ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Gross Margin Elements							
Mechanism Recoverable							
Labor	877	1,516	1,473	1,826	2,042	2,091	2,175
Resident Contractors	2,720	3,575	5,244	5,391	5,618	5,729	5,843
Environmental Maint & Ops	417	-	-	-	-	-	-
ECR Maintenance Of SCR/NOx Reduction Equip	447	395	103	105	107	109	111
ECR Baghouse Maintenance	10	380	798	851	861	923	935
ECR Fly Ash Disposal	(152)	(70)	100	107	114	121	128
ECR Activated Carbon	3,150	8,134	5,393	5,331	5,338	5,596	5,784
ECR Liquid Injection - Reagent Only	-	1,463	1,915	2,000	2,017	2,104	2,251
ECR Landfill Operations	3,078	2,854	2,195	2,219	2,250	2,291	2,295
ECR Landfill Maintenance	452	994	1,499	3,050	3,493	3,593	3,668
ECR CCP System Maintenance	(44)	1,014	203	1,176	2,175	2,232	2,289
ECR Maintenance-FGDs	206	663	859	891	899	1,062	1,070
ECR Nox Emission Allowances	6	-	-	-	-	-	-
ECR Nox Reduction Reagent	390	307	332	331	331	274	380
ECR Scrubber Reactant Ex	844	-	-	-	-	-	-
ECR Other Waste Disposal - Beneficial Reuse	288	558	1,059	1,059	1,058	1,059	1,059
ECR Sorbent Injection Maintenance	463	325	268	270	272	274	268
ECR Sorbent Injection Operation	47	27	92	96	100	104	106
ECR SO2 Emission Allowances	16	17	10	7	7	7	7
ECR Sorbent Reactant - Reagent Only	10,780	12,423	10,940	11,336	11,619	12,628	12,960
Total Mechanism recoverable	23,996	34,576	32,482	36,044	38,300	40,196	41,330

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2015-2021 Margin Expenses / Cost of Sales
All Other Cost of Sales ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Gross Margin Elements							
All Other Cost of Sales							
Labor	128	-	-	-	-	-	-
Resident Contractors	584	733	594	583	504	532	560
Environmental Maint & Ops	0	1	-	-	-	-	-
Activated Carbon	(0)	-	-	-	-	-	-
Liquid Injection - Reagent Only	2,123	3,178	2,493	2,452	2,704	2,471	2,898
Other Waste Disposal	931	763	831	592	92	141	167
NOx Reduction Reagent	6,683	5,666	5,955	5,811	6,092	6,487	6,555
Scrubber Reactant Ex	13,874	10,880	11,132	11,193	11,464	11,984	12,473
Sorbent Injection Operation	(15)	38	-	-	-	-	-
Sorbent Reactant - Reagent Only	1,898	1,265	1,861	1,845	2,080	2,142	2,322
Total All Other Cost of Sales	26,206	22,523	22,867	22,477	22,935	23,756	24,975
Total Margin/Cost of Sales	50,202	57,099	55,349	58,521	61,235	63,952	66,305

PPL companies

2017-2021 Margin/Cost of Sales Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Mechanism Recoverable					
Plan Expectation	48,419	54,700	56,189	58,581	78,456
Drivers:					
Brown Hg Additive flip from mech to non mech	(2,600)	(2,687)	(2,863)	(2,745)	(2,761)
ELG delay to 2022					(18,100)
Labor	609	617	580	615	652
Usage of Hydrated Lime	(3,272)	(3,758)	(3,462)	(3,538)	(3,588)
Usage of Hg additive	(5,560)	(6,138)	(6,241)	(7,208)	(7,509)
Landfill Operations and Maintenance	(1,930)	(3,415)	(2,515)	(2,279)	(2,589)
Baghouse Maintenance	(3,040)	(3,109)	(3,174)	(3,191)	(3,259)
Operation and maintenance of environmental equipment	(558)	(562)	(587)	(454)	(480)
Beneficial Reuse	519	530	543	555	552
Other Small Various Puts and Takes	(105)	(134)	(170)	(140)	(44)
Current Plan	32,482	36,044	38,300	40,196	41,330
Other Non Mechanism					
Plan Expectation	26,339	26,730	27,710	29,898	30,825
Drivers:					
Brown Hg Additive flip from mech to non mech	2,600	2,687	2,863	2,745	2,761
Usage of Limestone	(1,901)	(2,548)	(2,698)	(3,617)	(3,622)
Usage of Hydrated Lime TC2	(881)	(713)	(775)	(886)	(768)
Brown decrease in Hg additive	(1,670)	(1,708)	(1,820)	(2,053)	(1,678)
Usage of Ammonia	(1,864)	(2,042)	(1,834)	(1,768)	(2,016)
Other Small Various Puts and Takes	244	71	(511)	(563)	(527)
Current Plan	22,867	22,477	22,935	23,756	24,975
Grand Total Gross Margin Expense	**55,349**	**58,521**	**61,235**	**63,952**	**66,305**

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2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Mill Creek	219	222	216	214	214	214	214
Trimble County/CTs	158	163	169	176	176	176	176
Cane Run/Ohio Falls	51	51	50	50	49	48	48
Ghent	219	226	224	218	216	216	216
Brown/Dix/Tyrone	140	143	142	139	138	138	138
Green River	4	2	1	1	1	1	1
Commercial Operations	48	46	46	46	45	45	45
Other Generation Support	14	15	15	15	14	14	14
ELG headcount	-	-	-	24	24	24	24
Interns/temps	21	22	23	21	21	21	21
TOTAL	874	890	886	904	898	897	897
From 2016 Business Plan		885	881	889	894	937	
Change from 2016 Business Plan		5	5	15	4	(40)	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	13	(10)	(11)	(6)	(1)	
2.) Compliance – NERC, FERC, CIP, etc.		2				
3.) EPA/Environmental/ELG		1	31			
4.) Administrative/Corporate	3	1	(2)			
TOTAL	16	(4)	18	(6)	(1)	-
Contractor Offsets By Year: (New hire reducing contractor use)	-	-	-	-	-	-
Resident Contractors By Year:	428	428	426	436	437	437
Contractor Change from 2016 Plan	1	(3)	(15)	(7)	(7)	

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Plan Risks/Sensitivities

- Any subsequent changes to approved or proposed environmental regulations will impact the investment, construction and implementation of new systems and resources needed in this plan
- Generation dispatch for the plan years is based on current view of regulations and assumptions on pricing for gas supply and allowances which is subject to significant changes to unit cost profiles and maintenance schedules if changes occur
- Expansion of generating capacity and other generation changes consistent with approved integrated resource plan must be balanced with efforts to address transmission system load requirements. Additionally, the timing of retired coal and new Combined Combustion Gas Turbine (CCGT) availability will be critical
- Integration of additional CCR equipment, pond closures and dry landfill conversions will be on an aggressive schedule with potential to impact outage schedules.

Appendix

Operational Performance

Key Performance Indicators

KPI	2015 Actual	2016 Forecast*	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Generation (Twh)[1]	33.6	34.0	34.5	34.5	34.6	33.7	33.3
EAF (Steam)	82.3%	85.4%	85.2%	83.9%	84.1%	86.0%	86.2%
EFOR (Steam)	3.9%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Controllable Cost ($M)[2]	$287.4	$271.4	$257.3	$260.3	$280.9	$295.2	$292.1
Controllable Cost (per Mwh)[2]	$8.47	$7.98	$7.45	$7.55	$8.13	$8.75	$8.78
Cash Cost (per Mwh)[3]	$11.96	$10.72	$11.00	$12.00	$13.27	$12.02	$12.83
Cost Per Mwh [4]	$7.63	$7.84	$7.91	$8.24	$8.57	$8.84	$9.16
Recordable Injuries[5]	1.95	1.03	1.98	1.95	1.91	1.88	1.84
Lost Workday Case Rate[5]	0.54	0.21	0.32	0.32	0.32	0.32	0.32
Days Away/Restricted/Transferred Case Rate (DART)[5]		0.21	0.83	0.83	0.81	0.80	0.79

[1] Steam Generation includes 75% of Trimble County 1 and 2.

[2] Controllable Costs include Utility O&M, Other Cost of Sales, and Below-the-Line expenses.

[3] Cash cost includes controllable costs plus capital divided by MWH (75% TC)

[4] Five year average - measure is non fuel O&M used in FERC benchmarking and includes all lines of business divided by MWH (75% TC)

[5] The 2016 forecast for RIIR (including hearing loss),Lost Workday Case Rate and DART is the July YTD value

*2016 Forecast is from the 7&5 forecast.

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2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	222,737
CR severance	(3,590)
CR Inventory Write offs	(7,884)
Green River plant closure non labor	(7,385)
Green River reg asset	4,917
CR steam and CR7 non labor non outage net	(1,643)
Outages	(3,374)
Labor	(2,161)
Other	(1,461)
2016 FC	200,155
Outages	2,965
Labor	2,196
Maintenance	(1,528)
Green River reg asset	(587)
Other	1,775
2017 Budget	204,976
Outages	10,860
Maintenance	5,076
Labor	1,371
Green River reg asset	(587)
Other	693
2018 Plan	222,388
Outages	7,467
Maintenance	1,941
Labor	1,699
Green River reg asset	(939)
Other	1,430
2019 Plan	233,985
Outages	(11,771)
Maintenance	2,467
Labor	2,648
Green River reg asset	(470)
Other	1,335
2020 Plan	228,194
Outages	1,248
Maintenance	(3,136)
Labor	2,231
Other	1,059
2021 Plan	229,596

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2015-2021 Walk Forward for GMEXP / Cost of Sales ($000)

Mechanism		**Non Mechanism**	
2015 Actual	23,996	**2015 Actual**	26,206
Baghouse Operations and Maintenance	583	Cane Run closure	(3,687)
Sorbent Injection systems'	(510)	Scrubber reactant (limestone)	347
Sorbent reactant (Hydrated Lime)	1,643	Mercury Additive	1,055
Landfill Operations and Maintenance	2,407	Sorbent reactant (Hydrated Lime)	(634)
Mercury Additive	6,447	NOX reduction agent (Ammonia)	(1,016)
Other	10	Other	252
2016 FC	34,576	**2016 FC**	22,523
Mercury Additive	(2,289)	NOX reduction agent (Ammonia)	289
Beneficial Reuse	500	Mercury Additive	(684)
Landfill Operations and Maintenance (TC)	628	Scrubber reactant (limestone)	252
Baghouse Operations and Maintenance	260	Sorbent reactant (Hydrated Lime)	597
Sorbent reactant (Hydrated Lime)	(1,484)	Other	(110)
Other	290	**2017 Budget**	22,867
2017 Budget	32,482	Ash Pond hauling MC	(583)
Sorbent reactant (Hydrated Lime)	396	Other	193
Landfill Operations and Maintenance (TC)	2,999	**2018 Plan**	22,477
Other	167	Scrubber reactant (limestone)	271
2018 Plan	36,044	Other	186
Landfill Operations and Maintenance (TC)	1,848	**2019 Plan**	22,935
Sorbent reactant (Hydrated Lime)	283	Scrubber reactant (limestone)	519
Other	126	Sorbent reactant (Hydrated Lime)	63
2019 Plan	38,300	Other	239
Sorbent reactant (Hydrated Lime)	1,010	**2020 Plan**	23,756
Landfill Operations and Maintenance	314	Scrubber reactant (limestone)	490
Mercury Additive	345	Mercury Additive	427
Other	228	Sorbent reactant (Hydrated Lime)	179
2020 Plan	40,196	Other	123
Sorbent reactant (Hydrated Lime)	331	**2021 Plan**	24,975
Mercury Additive	336		
Other	467		
2021 Plan	41,330		

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2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (as of July 2016)	897	428
Interns	1	
Plant Operations (retirements)	(8)	
2016 Headcount FC - Year End	890	428
Interns	1	
Plant Operations (retirements)	(5)	
2017 Headcount Budget	886	428
Interns	(2)	
ELG all plants	24	
Environmental (TC CCR)	7	
Plant Operations (retirements)	(11)	(2)
2018 Headcount Plan	904	426
Environmental (TC CCR)		9
Commercial Operations (retirement)	(1)	
Plant Operations (employee retirements)	(5)	1
2019 Headcount Plan	898	436
Plant Operations (retirements)	(1)	1
2020 Headcount Plan	897	437
2021 Headcount Plan	897	437

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2015-2021 Other Balance Sheet Costs ($000)

Item	2015 Actual	2016 Forecast	2017 Budget	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Stores Expense							
Labor	2,821	2,173	2,430	2,420	2,444	2,517	2,564
Non labor	1,052	1,068	860	881	903	926	949
Total	3,873	3,241	3,290	3,301	3,348	3,443	3,513
Local Engineering							
Labor	39	1,426	1,543	1,667	1,682	1,728	1,685
Sales tax refund		(826)					
Non labor	151	43	22	24	24	24	22
Total	190	643	1,565	1,690	1,706	1,752	1,707
Total Other Costs	4,063	3,884	4,855	4,992	5,054	5,195	5,220

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LG&E KU PPL companies

PPL companies

Electric Distribution Operations

2017 Business Plan

September 2016






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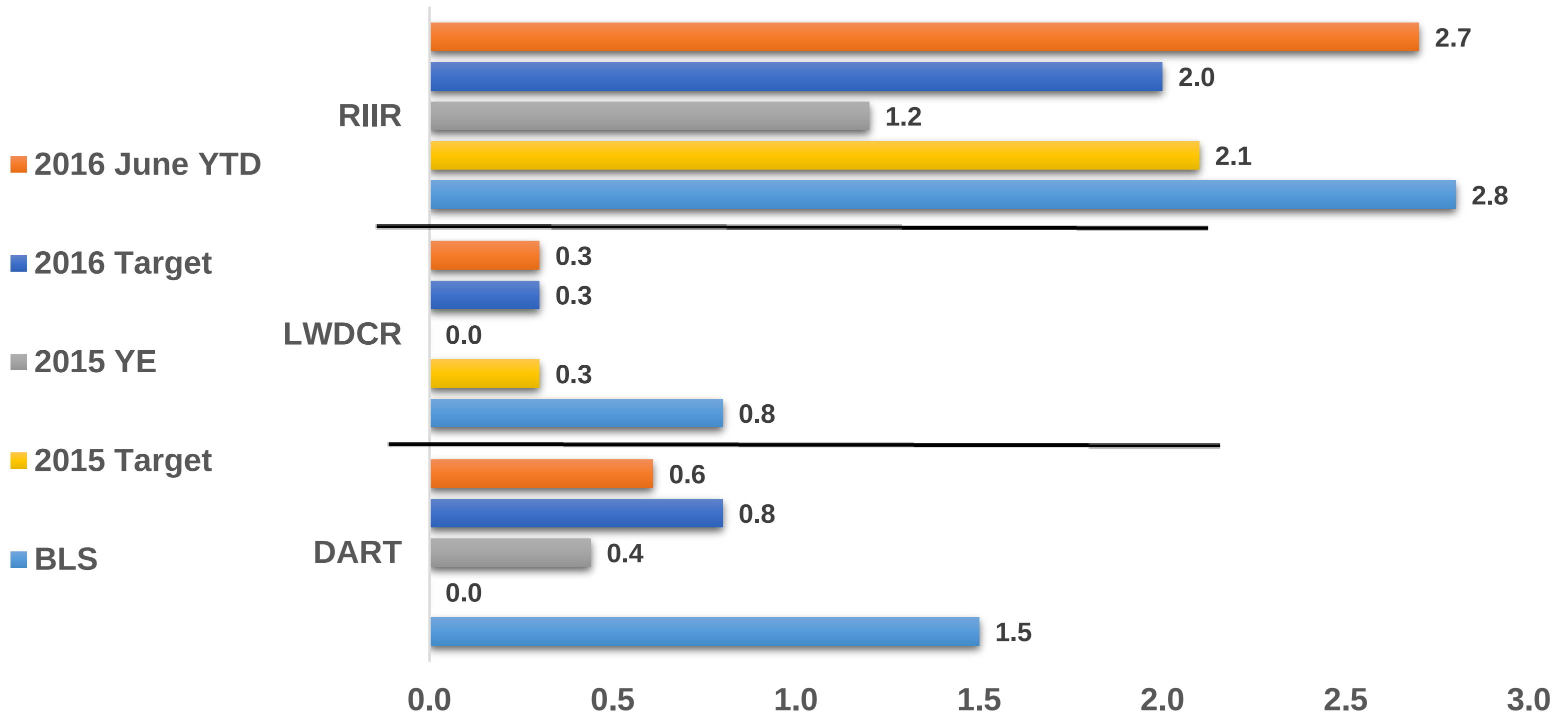
Plan Highlights

Electric Distribution's Business Plan provides for continued emphasis on the Company's core values of safety and customer satisfaction. Plan funding will continue to provide for safe, reliable, resilient and low cost electric service for customers, with priority given to the following:

- Employee, business partner and public safety
- Transfer of knowledge to new employees as retirements accelerate
- System enhancements to meet existing and future customer loads
- Electric system automation, hardening and protection to improve service reliability and system resiliency
- Technology advancements to enhance business processes, improve operational efficiencies and enhance communications with customers
- Asset replacements to address aging infrastructure
- Construction projects to serve new customers and satisfy customer requested projects
- Maintenance, inspections and operations programs which assure regulatory compliance and operational performance

Plan Highlights

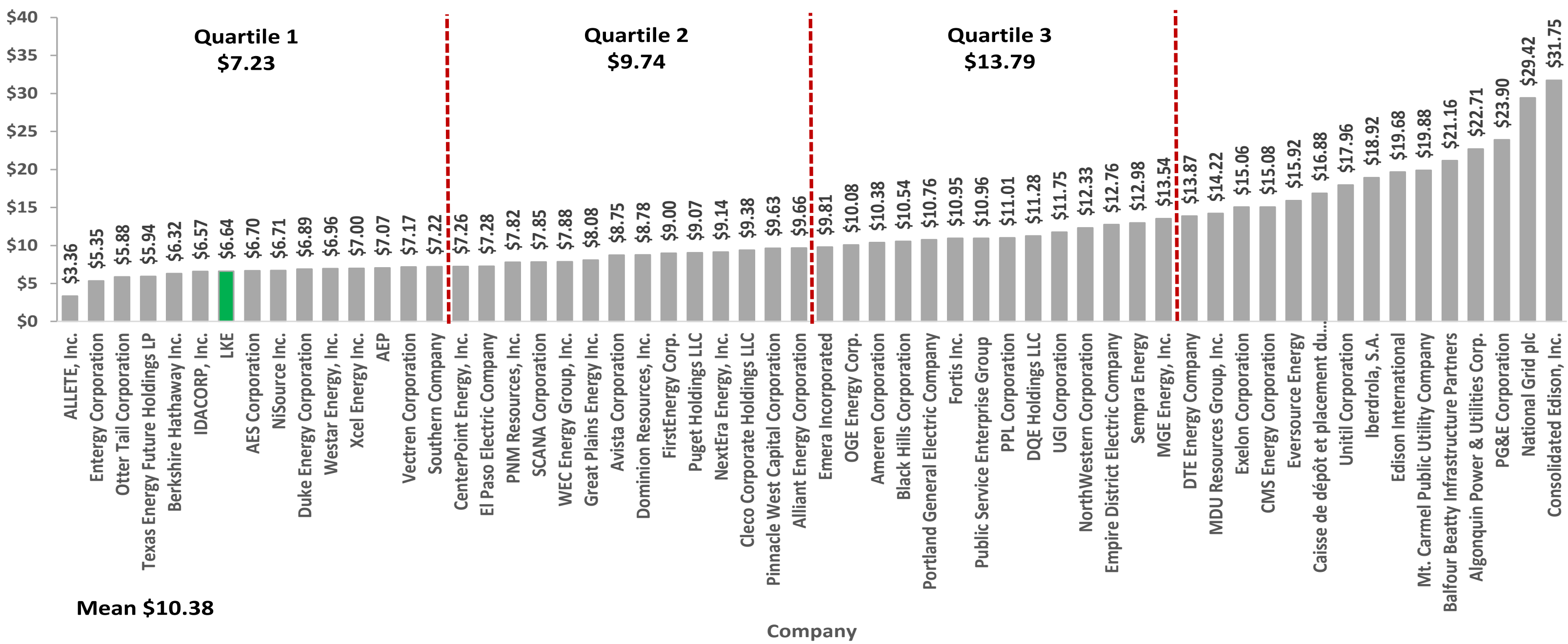
Safety Performance - Electric



PPL companies

Plan Highlights

Total DO Electric Cash Cost per MWh



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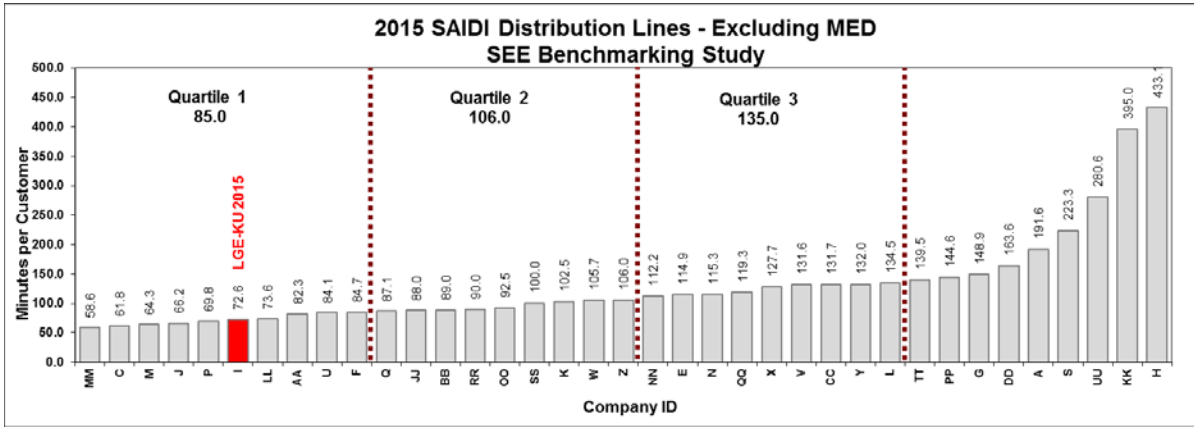
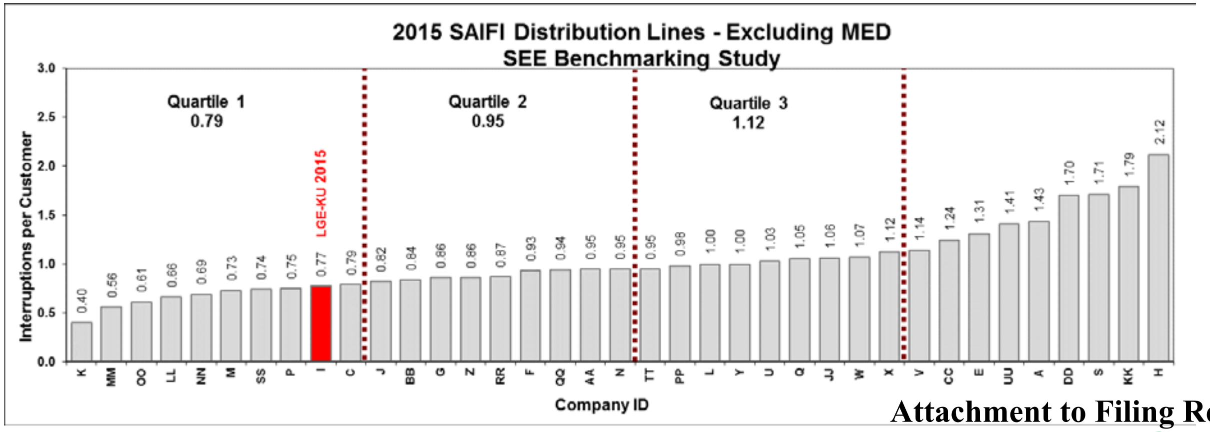
Plan Highlights

Reliability Performance





PPL companies

Plan Highlights

- Safety and Wellness
  - *Continue commitment to employees, business partners and public safety*
  - *Focus on incident prevention plans and critical danger zones*
  - *Support the transfer of safety knowledge from seasoned to new employees*
  - *Ensure a comprehensive safety/technical training plan is in place for all employees*
  - *Maintain industry leading performance*
  - *Benchmark and implement industry best practices*
  - *Continue to improve motor vehicle safety*
  - *Promote wellness initiatives as an aspect of safety to ensure employees are in optimal physical condition to prevent work related illnesses and injuries*

Plan Highlights

- Customer Experience
  - *Respond effectively and efficiently to customer requests for service*
  - *Invest in system reliability and contingency to meet increasing customer expectations respective to service availability*
  - *Invest in aging infrastructure to continue long term service reliability*
  - *Advance grid intelligence to meet evolving customer expectations*
  - *Respond to outage events in a timely and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times*
  - *Build on technology which enhances business processes, reduces cycle times, and expands communications with customers*
  - *Focus on portraying a professional and positive customer image*
  - *Satisfy customer capacity needs*

Plan Highlights

- OPEX
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2016-2021 is 3.4% in total, 3.0% without storms and 2.3% without storms and line clearing.*
  - — *Over the 15 year period, CAGR from 2007-2021 is 2.6% in total, 2.2% without storms and 1.7% without storms and line clearing.*
  - — *Major Initiatives:*
    - Line Clearance, Hazard Tree Program and Emerald Ash Borer Mitigation
    - Regulatory Inspection and Maintenance Programs
    - System Trouble and Storm Response
  - — *Major Financial Risks:*
    - Nondiscretionary OPEX Work (preventing allocation of labor to prudent capital initiatives)
    - Storm Damages that Exceeds the 10 Year Average
    - Accelerated Demise of Ash Trees

Plan Highlights

- Capital
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Continued focus on critical capital investments related to connecting new customers, meeting customer demand, enhancing system reliability and resiliency, replacing aging infrastructure, and repairing the system.*
  - — *Major Initiatives:*
    - System expansion to serve new customers
    - Major substation and circuit enhancements to meet demand
    - Distribution reliability and resiliency programs including Distribution Automation, Circuits Identified for Improvement (CIFI), and N-1 Distribution Transformers
    - Aging Infrastructure Replacement (AIR) including the Pole Inspection and Treatment Program (PITP), Paper Insulated Lead Cable (PILC) Replacement, and Substation Exit Cable Replacement.
    - Information Technology Investments including purchase and deployment of a Distribution Management System, and GIS Replacement
    - Make Ready Pole Replacements for Major 3rd Party Pole Attachment Projects
    - Construction of a consolidated Distribution Control Center (DCC) Facility at Simpsonville

Major Assumptions

— *Reliability investments over plan period will continue to target improvement in key reliability metrics and system resiliency:*

- Continuation of targeted system hardening and reliability improvement projects based on circuit reliability performance and specific customer interruption frequencies – $55.8M
- Implementation of Distribution Automation – $98.2M
- Advancement of the N-1 Distribution Transformer Program – $47.8M

— *Maintenance and repair blankets will continue to be funded based on historical trends and projected work volumes.*

— *The Pole Inspection and Treatment Program will continue through the plan period.*

Major Assumptions

- Louisville Downtown Network Paper Insulated Lead Cable (PILC) replacement
- Substation legacy equipment replacement
- LG&E substation underground exit cables replacement
- Overhead lines rear easement hardening

— *LG&E escalation assumed at 5% (2% growth and 3% material/labor increases).*

— *KU escalation assumed at 3% (0% growth and 3% material/labor increases).*

— *Funding included for known major customer expansions/additions.*

Major Assumptions

- Plan includes $10 million for proposed construction of a combined Distribution Control Center at the Simpsonville Transmission Control Center site.
- Incremental headcount proposed to:
  - *Implement and support Distribution Automation and N-1 Distribution Transformer programs*
  - *Advance hire key technical positions to facilitate knowledge transfer for projected retirements*

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	**24,762**	**24,404**	**24,323**	**25,505**	**26,313**	**27,263**	**27,585**
Non Labor							
Line Clearance [1]	22,979	22,956	23,693	23,528	24,603	25,116	25,558
Storm Restoration [2]	5,776	3,928	6,497	7,170	7,359	7,525	7,729
Outside Services - Resident	3,199	6,733	9,702	9,722	9,822	9,959	10,099
Outside Services - Other	5,017	1,879	224	229	272	276	280
Sub-Total Outside Services [3]	8,216	8,612	9,925	9,951	10,094	10,236	10,379
Materials	4,266	3,761	4,173	4,139	4,142	4,204	4,267
Transportation and Equipment	4,158	4,086	4,115	4,282	4,410	4,476	4,543
Other Non Labor	1,338	1,318	1,597	1,597	1,646	1,582	1,514
Total Non Labor	**46,734**	**44,661**	**50,000**	**50,668**	**52,254**	**53,139**	**53,991**
Total O&M Expense	**71,496**	**69,065**	**74,323**	**76,173**	**78,567**	**80,401**	**81,576**

1) Total Line Clearance including labor is $23.9M for 2015, $23.8M for 2016, $24.6M for 2017, $24.4M for 2018, $25.5M for 2019, $26.2M for 2020, and $26.6M for 2021.

2) Total Storm Restoration including labor is $8.5M 2015, $6.4M for 2016, $9M for 2017 and $9.3M for 2018, $9.5M for 2019, $9.8M for 2020, and $10M for 2021.

3) The Resident contractor expenditure type wasn't fully implemented until 2016.

O&M Annual Expense Reconciliation
($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	74,116	75,932	78,291	80,120	81,197
Drivers:					
Storm Restoration to 10 yr. Ave.	255	289	326	333	340
Other	(48)	(48)	(50)	(52)	39
Current Plan	74,323	76,173	78,567	80,401	81,576

PPL companies

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
VP EDO	2	2	2	2	2	2	2
Transportation	3	3	3	3	3	3	3
System Restoration & LG&E Distribution	204	211	217	223	223	225	223
Electric Reliability	14	14	16	16	16	16	16
KU Distribution	302	302	303	303	303	303	303
Asset Management & Substations	171	173	176	174	173	174	173
Interns	5	12	3	3	3	3	3
TOTAL	**701**	**717**	**720**	**724**	**723**	**726**	**723**
From 2016 Business Plan		711	717	720	719	719	
Change from 2016 Business Plan		6	3	4	4	7	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	15	4	4	(1)	3	(3)
2.) Compliance – NERC, FERC, CIP, etc.	1	(1)				
3.) EPA/Environmental						
4.) Administrative/Corporate						
TOTAL	**16**	**3**	**4**	**(1)**	**3**	**(3)**
Contractor Offsets By Year: (New hire reducing contractor use)	1	1				

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	861	904	904	904	904	904
Contractor Change from 2016 Plan	(76)	(27)	(24)	(24)	(24)	

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LG&E KU PPL companies

Plan Risks

Appendix

Operational Performance

Key Performance Indicators

KPI	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Safety - Employees Incident Rate [1]	1.16	2.21	1.98	1.95	1.91	1.88	1.84
Safety - Contractors Incident Rate [1]	1.64	2.00	1.98	1.95	1.91	1.88	1.84
DART - Employees [1]	0.44	0.66	0.83	0.83	0.81	0.80	0.79
SAIFI	0.840	0.860	0.840	0.803	0.749	0.712	0.688
SAIDI	77.78	87.08	82.20	81.03	78.85	77.25	76.51
Residential New Business Cycle Time (Business Days) [2]	n/a	n/a	3.00	3.00	3.00	3.00	3.00
Repair Street Lights (Business Days) [3]	n/a	n/a	2.00	2.00	2.00	2.00	2.00
Electric Trouble Arrival Response Time (Minutes) [4]	n/a	n/a	TBD	TBD	TBD	TBD	TBD
Estimated Restoration Time (ERT) Accuracy [5]	n/a	92%	90%	90%	90%	90%	90%
Cash Cost Per MWH Sold - 5 Yr. Avg. Calculation	6.64	7.14	7.69	8.84	9.87	10.42	10.88

1) 2016 Forecast is YTD August.
2) Measures the time between the approved inspection and the connection to the customer.
3) Measures the duration from once the call is received to when we are onsite to assess / repair.
4) Measures the time frame between the first call and arrival time for emergency calls on Blue Sky Days only.
5) 2016 Forecast is YTD August. Measures the percentage that service is restored on or before the ERT.

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2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	**71,496**
Labor Changes	(401)
Labor Changes - Distribution Automation	43
Line Clearance	(23)
Storm Restoration	(1,848)
Net Other Changes	(202)
2016 FC	**69,065**
Labor Changes	(383)
Labor Changes - Distribution Automation	302
Line Clearance	737
Storm Restoration	2,569
Net Other Changes	2,033
2017 Plan	**74,323**
Labor Changes	497
Labor Changes - Distribution Automation	685
Line Clearance	(165)
Storm Restoration	673
Net Other Changes	160
2018 Plan	**76,173**

2018 Plan	**76,173**
Labor Changes	454
Labor Changes - Distribution Automation	354
Line Clearance	1,075
Storm Restoration	189
Net Other Changes	322
2019 Plan	**78,567**
Labor Changes	909
Labor Changes - Distribution Automation	41
Line Clearance	513
Storm Restoration	166
Net Other Changes	205
2020 Plan	**80,401**
Labor Changes	279
Labor Changes - Distribution Automation	43
Line Clearance	442
Storm Restoration	204
Net Other Changes	207
2021 Plan	**81,576**

(Decreases)/Increases

PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of August 2016)	**704**	**890**
System Restoration & LG&E Distribution	3	
Electric Reliability	0	(28)
KU Distribution	3	
Asset Management & Substations	7	(1)
2016 Headcount FC - Year End	**717**	**861**
System Restoration & LG&E Distribution	6	18
Electric Reliability	2	25
KU Distribution	1	
Asset Management & Substations	3	
Interns	(9)	
2017 Headcount Plan	**720**	**904**

	Company Employees	Resident Contractors
2017 Headcount Plan	**720**	**904**
System Restoration & LG&E Distribution	6	
Asset Management & Substations	(2)	
2018 Headcount Plan	**724**	**904**
Asset Management & Substations	(1)	
2019 Headcount Plan	**723**	**904**
System Restoration & LG&E Distribution	2	
Asset Management & Substations	1	
2020 Headcount Plan	**726**	**904**
System Restoration & LG&E Distribution	(2)	
Asset Management & Substations	(1)	
2021 Headcount Plan	**723**	**904**

The contractor numbers do not include incremental contractors that may be necessary for some of the new/major programs such as DA, N1DT, Google.

2015-2021 Other Balance Sheet Costs
($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Local Engineering							
Labor	14,890	14,761	16,077	16,182	16,171	16,575	16,989
Non labor	3,455	3,492	2,916	2,745	2,884	2,927	2,971
Total	18,345	18,253	18,993	18,926	19,055	19,503	19,961
Transportation	21,638	21,859	22,586	23,039	23,505	23,864	24,228
Total Other Costs	39,983	40,112	41,579	41,965	42,560	43,367	44,188

PPL companies

Gas Distribution Operations

2017 Business Plan

September 2016






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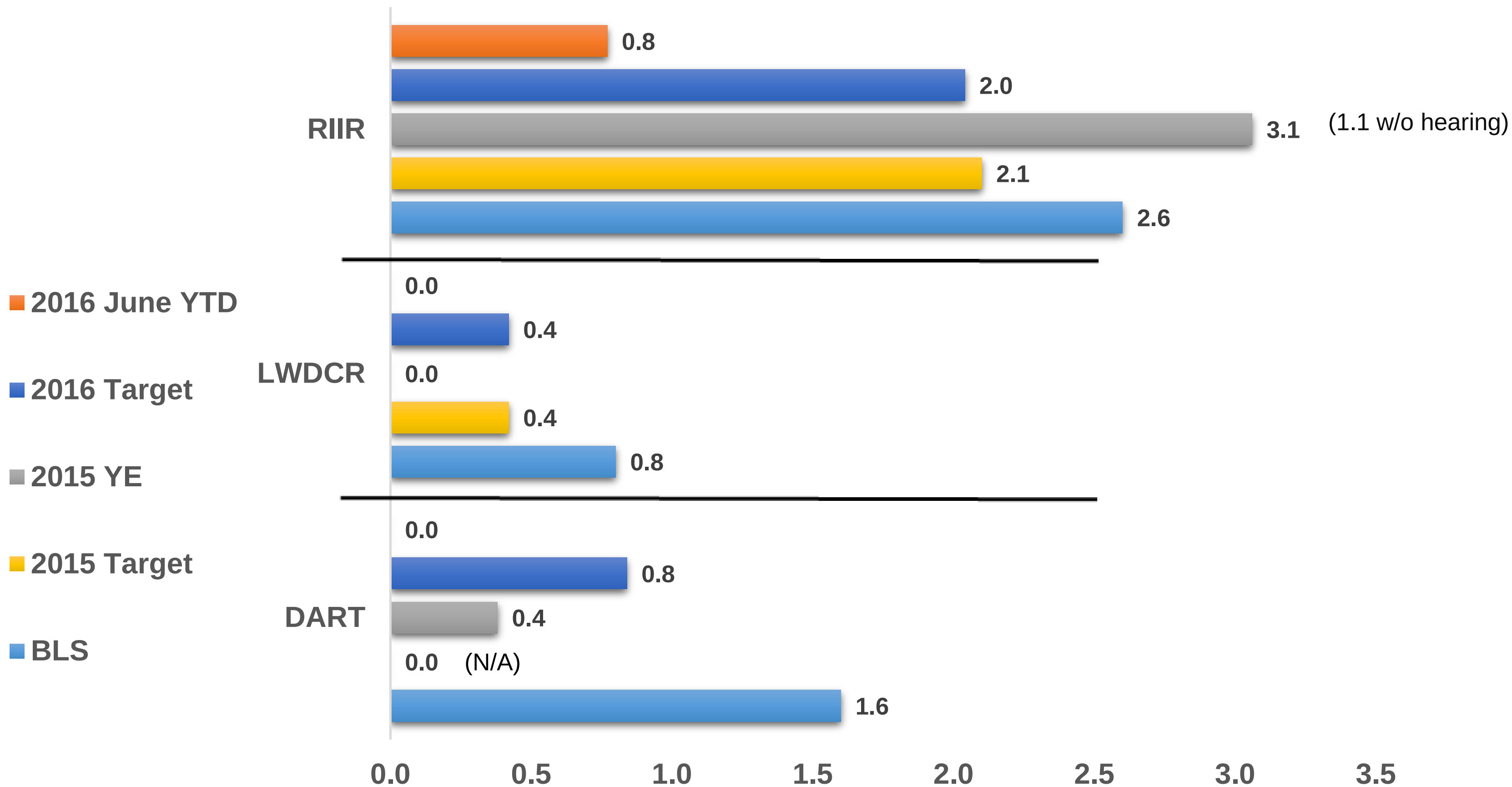
Plan Highlights

- Funding levels within the proposed plan were established with the following priorities in mind:
  - Employee, contractor and public safety
  - Regulatory compliance
  - Enhanced customer service
  - Gas system reliability
  - Asset replacement to ensure reliable and safe service
  - System enhancements to meet customer needs
  - Technology to increase efficiencies and enhance customer experience
  - Capital investments for gas riser and service line ownership

LG&E KU
PPL companies

Plan Highlights

Safety Performance - Gas



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LG&E KU
PPL companies

Plan Highlights

- Safety and Wellness
  - *Continuously strive to improve employee safety performance*
  - *Improve gas system safety thru effective: Distribution Integrity, Transmission Integrity, Public Awareness, Damage Prevention and Gas Control Room Management programs*
  - *Maintain strong safety partnerships with business partners*
  - *Enhanced public safety thru customer communications, asset replacement*
  - *Continuation of motor vehicle safety initiatives*
  - *Identify, share, and capitalize on industry best practices*
  - *Mock drills, leak detection training, and emergency response improvements*
  - *Promote wellness initiatives as an aspect of safety to ensure employees are in optimal physical condition to prevent work related illnesses and injuries*

Plan Highlights

- Customer Experience
  - *Meet customer expectations for new service requests*
  - *Promptly address customer service issues*
  - *Identify customer service improvement opportunities*
  - *Invest in aging infrastructure to ensure reliable and safe service*
  - *Promote professional and positive corporate image to customers*
  - *Restore customer service outages quickly and efficiently*
  - *Meet customer capacity needs*
  - *Implement technology to enhance customer service*
  - *Proactively communicate with customers*

PPL companies

Plan Highlights

- Reliability, Infrastructure and Regulatory Compliance
  - *Investments in infrastructure to meet customer needs*
  - *Investment in aging infrastructure to improve safety, reliability and performance*
  - *Effectively manage gas distribution and transmission integrity management regulatory programs*
  - *Provide reliable gas supplies thru investments in:*
    - Gas regulation/measurement facilities
    - Gas transmission system
    - Gas compressor stations
    - Gas storage fields
    - Distribution infrastructure upgrades

PPL companies

Plan Highlights

- Workforce Development
  - *Headcount plan that addresses high number of expected retirements*
  - *Identification of pre-hires for critical job positions*
  - *Knowledge transfer to new employees*
  - *Support of employee continuing education initiatives*
  - *Job aid development to reinforce On-the-Job Training and promote consistent work practices across operational groups*
  - *Internal and external training opportunities*
  - *Mobile computing technologies supporting training*
  - *Participation in trade school internship program*

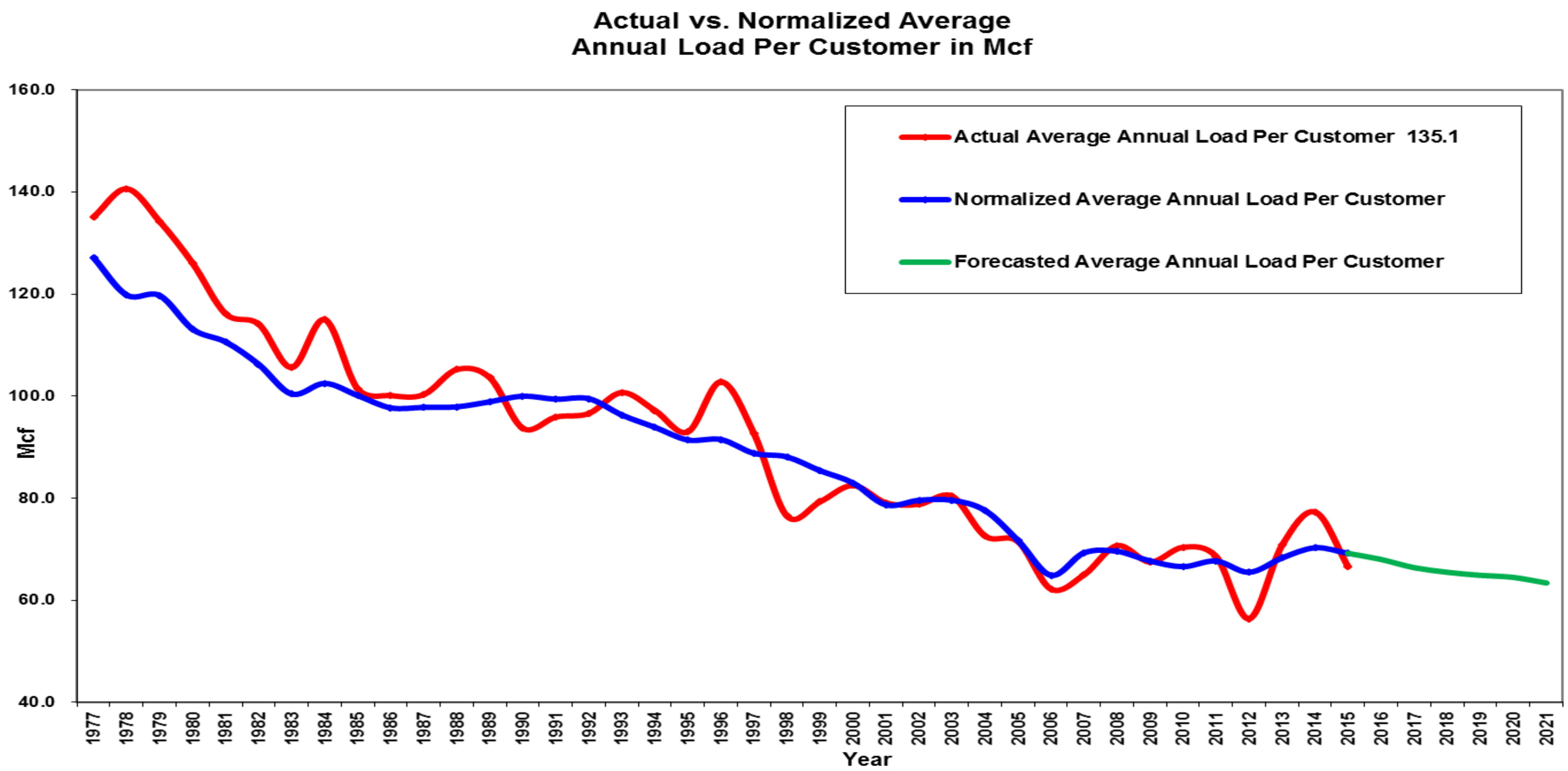
Plan Highlights

- OPEX
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2016-2021 is 3.2%.*
  - — *Major Initiatives:*
    - Regulatory Compliance
    - Implement key headcount additions
    - In-line inspection of pipelines
  - — *Major Financial Risks:*
    - Regulatory Uncertainty including MAOP validation and gas storage integrity requirements
    - Line locating costs due to fiber projects and general construction increases
- Cost of Sales
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2016-2021 is 3.7%.*
  - — *Major Initiatives:*
    - Gas Main & Riser Replacement Programs
  - — *Major Financial Risks:*
    - Regulatory Uncertainty including MAOP validation requirements

Plan Highlights

- Capital
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Major Capital Initiatives:*
    - Reliability / Asset Replacement
    - Gas Leak Mitigation
    - Customer Service Ownership and Service Riser Replacement Programs
    - Steel Service Line Replacement Program
    - Transmission Line Replacement Project
    - Compressor Station and System Enhancements
    - Storage Well Replacement Program
    - Transmission/Distribution Integrity Management Programs
    - Distribution System Reinforcements

Residential Gas Use per Customer



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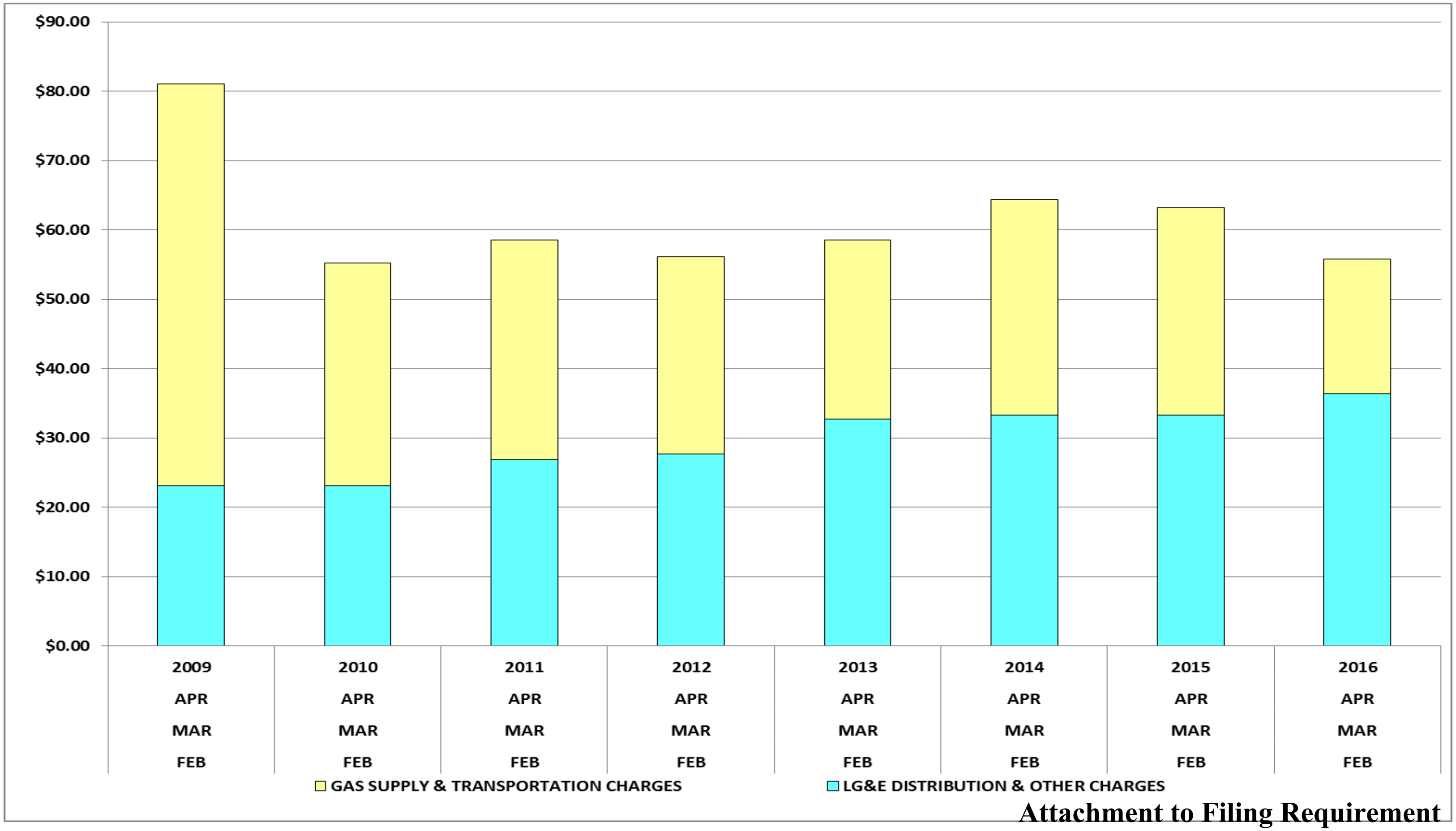
Typical Monthly Residential Gas Bill by Component (6 Mcf/month)



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Gas Delivered by Class in Bcf

Class	2016	2017	2018	2019	2020	2021
Residential	20.094	19.650	19.438	19.279	19.227	18.946
Commercial	10.360	10.224	10.166	10.068	9.963	9.790
Industrial	1.616	1.695	1.739	1.789	1.845	1.903
Transportation	13.764	12.997	13.045	13.107	13.160	13.122
Total	45.834	44.566	44.388	44.243	44.195	43.761

Major Assumptions

Major Assumptions

- *Require operators to validate MAOPs of gas transmission pipelines.*
- *Expand pipeline integrity requirements beyond high consequence areas.*
- *Expand operator qualification requirements to construction activities.*
- *Require continuous improvement for distribution system integrity.*
- *Require development of gas storage integrity programs.*

- *Forecasted Design Day for 2017 is expected to increase to 679,000 Mcf/day from 674,000 Mcf/day estimated in the prior BP. During the current 5-year planning period, the forecasted Design Day is expected to gradually decrease to 671,000 Mcf/day.*
- *Gas storage operating risk is addressed through staffing plan and reliability enhancement projects.*
- *Main replacement and gas riser projects will address infrastructure vulnerable to cold weather issues.*

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	17,219	17,590	18,826	19,560	19,496	19,983	20,483
Non Labor							
Inline Inspections	494	503	476	1,167	1,516	456	548
Outside Services - Resident	4,191	6,640	7,065	7,283	7,849	7,966	8,086
Outside Services - Other	4,774	1,298	1,147	967	1,116	1,334	1,348
Sub-Total Outside Services [1]	8,965	7,937	8,212	8,250	8,965	9,300	9,433
Materials	3,591	3,176	3,732	4,044	3,938	3,997	4,057
Transportation and Equipment	2,046	2,045	1,901	1,963	1,994	2,023	2,054
Other Non Labor	1,700	1,742	1,839	1,883	1,933	1,962	1,990
Total Non Labor	16,796	15,403	16,160	17,307	18,345	17,738	18,082
Total O&M Expense	**34,015**	**32,993**	**34,986**	**36,867**	**37,841**	**37,722**	**38,565**

1) The Resident contractor expenditure type wasn't fully implemented until 2016.

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	34,056	35,791	35,702	36,579	37,310
Drivers:					
Headcount Changes	941	1,093	1,012	943	959
Compliance Programs			291		
Doe Run Storage Field Shale Gas Recovery Operations			425		
Other	(11)	(17)	411	200	296
Current Plan	34,986	36,867	37,841	37,722	38,565

PPL companies

2015-2021 Margin Expenses / Cost of Sales ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Margin Expenses							
Mechanism Recoverable:							
Gas Tracker	2,564	1,038	1,379	1,350	1,387	1,412	1,437
Gas Losses	1,690	1,607	1,542	1,663	1,683	1,708	1,734
Total	4,254	2,645	2,921	3,013	3,070	3,120	3,171

LG&E KU PPL companies

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
<u>**Mechanism Recoverable**</u>					
Plan Expectation	8,193	18,257	19,832	13,409	13,466
Drivers					
MAOP - Pressure Testing	(5,000)	(15,000)	(16,500)	(10,000)	(10,000)
Gas Tracker - Revised Estimates	3	(54)	(55)	(69)	(70)
Gas Losses - Lower Estimate	(275)	(190)	(207)	(220)	(225)
Current Plan	**2,921**	**3,013**	**3,070**	**3,120**	**3,171**

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2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
VP Gas Distribution Operations	2	2	2	2	2	2	2
Gas Regulatory	33	35	39	39	38	37	37
Gas Management & Supply	6	6	6	6	6	6	6
Gas Operations, Construction & Engineering	111	118	123	123	120	120	120
Gas Control & Storage	104	114	110	110	107	106	106
Interns	1	4	4	4	4	4	4
TOTAL	**257**	**279**	**284**	**284**	**277**	**275**	**275**
From 2016 Business Plan		278	276	276	270	268	
Change from 2016 Business Plan		1	8	8	7	7	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	22	(4)	(2)	(6)	(2)	
2.) Compliance – NERC, FERC, CIP, etc.		9	2	(1)		
3.) EPA/Environmental						
4.) Administrative/Corporate						
TOTAL	**22**	**5**	**0**	**(7)**	**(2)**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)		1				

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	388	387	287	287	287	287
Contractor Change from 2016 Plan	7	6	6	6	[illegible]	

PPL companies

Plan Risks

Appendix

Operational Performance

Key Performance Indicators

KPI	2015 Year End	2016 Forecast [1]	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Safety - Employee Incident Rate	3.06	2.90	1.98	1.95	1.91	1.88	1.84
Safety - Contractors Incident Rate	1.64	2.57	1.98	1.95	1.91	1.88	1.84
DART - Employees	0.38	0.00	0.83	0.83	0.81	0.80	0.79
Gas Response Priority 1 Calls (minutes)	39.00	34.80	41.25	41.00	40.75	40.50	40.00
New Business Cycle Time (Calendar Days) [2]	7.70	6.90	9.00	9.00	9.00	9.00	9.00

1) 2016 Forecast is YTD through August.
2) Measures from the time a service request is approved by a locator from the Design department to the time the service is installed.

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LG&E KU PPL companies

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	**34,015**
Labor Changes	371
Pipeline Inline Inspections	9
Net Other Changes	(1,402)
2016 FC	**32,993**
Labor Changes	1,236
Pipeline Inline Inspections	(27)
Net Other Changes	784
2017 Plan	**34,986**
Labor Changes	734
Pipeline Inline Inspections	691
Budget Stretch	(311)
Net Other Changes	767
2018 Plan	**36,867**

2018 Plan	**36,867**
Labor Changes	(64)
Pipeline Inline Inspections	349
Budget Stretch	107
Net Other Changes	582
2019 Plan	**37,841**
Labor Changes	487
Pipeline Inline Inspections	(1,060)
Budget Stretch	204
Net Other Changes	250
2020 Plan	**37,722**
Labor Changes	500
Pipeline Inline Inspections	92
Net Other Changes	251
2021 Plan	**38,565**

(Decreases)/Increases

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LG&E KU PPL companies

2015-2021 Walk Forward for GMEXP / Cost of Sales ($000)

2015 Actual	**4,254**
Gas Tracker	(1,526)
Gas Losses	(83)
2016 FC	**2,645**
Gas Tracker	341
Gas Losses	(65)
2017 Plan	**2,921**
Gas Tracker	(29)
Gas Losses	121
2018 Plan	**3,013**
Gas Tracker	37
Gas Losses	20
2019 Plan	**3,070**
Gas Tracker	25
Gas Losses	25
2020 Plan	**3,120**
Gas Tracker	25
Gas Losses	26
2021 Plan	**3,171**

(Decreases)/Increases

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LG&E KU PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of August 2016)	**267**	**388**
Gas Regulatory	0	0
Gas Operations, Construction, & Engineering	2	0
Gas Control & Storage	10	0
2016 Headcount FC - Year End	**279**	**388**
Gas Regulatory	4	0
Gas Operations, Construction, & Engineering	5	(1)
Gas Control & Storage	(4)	0
2017 Headcount Plan	**284**	**387**
Gas Regulatory	0	0
Gas Operations, Construction, & Engineering	0	(100)
Gas Control & Storage	0	0
2018 Headcount Plan	**284**	**287**
Gas Regulatory	(1)	0
Gas Operations, Construction, & Engineering	(3)	0
Gas Control & Storage	(3)	0
2019 Headcount Plan	**277**	**287**
Gas Regulatory	(1)	0
Gas Operations, Construction, & Engineering	0	0
Gas Control & Storage	(1)	0
2020 Headcount Plan	**275**	**287**
Gas Regulatory	0	0
Gas Operations, Construction, & Engineering	0	0
Gas Control & Storage	0	0
2021 Headcount Plan	**275**	**287**

PPL companies

2015-2021 Other Balance Sheet Costs ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Local Engineering							
Labor	2,293	2,398	2,786	2,880	2,966	3,040	3,116
Non labor	174	133	153	158	161	163	166
Total	2,467	2,531	2,939	3,037	3,127	3,203	3,282

LG&E KU PPL companies

PPL companies

Customer Services

2017 Business Plan

September 2016

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Plan Highlights

Customer focus is a core value at LG&E and KU. Customer Services strives to provide safe, reliable, and reasonable cost service to our customers, improving the quality of life in the areas we serve. Additionally, we are committed to enhancing our relationship with our customers by delivering positive experiences that create value and build trust.

•Funding levels within the proposed plan are established with the following priorities in mind:

- Employee and public safety including compliance with industry regulatory requirements
- Continuing Energy Efficiency programs and services for our customers
- Implementation of AMS
- Maintaining operational performance levels
- Investing in technology to enhance customer experience
- Facility improvements based on Master Facility Plan
- Managing “best in class” bad debt expense

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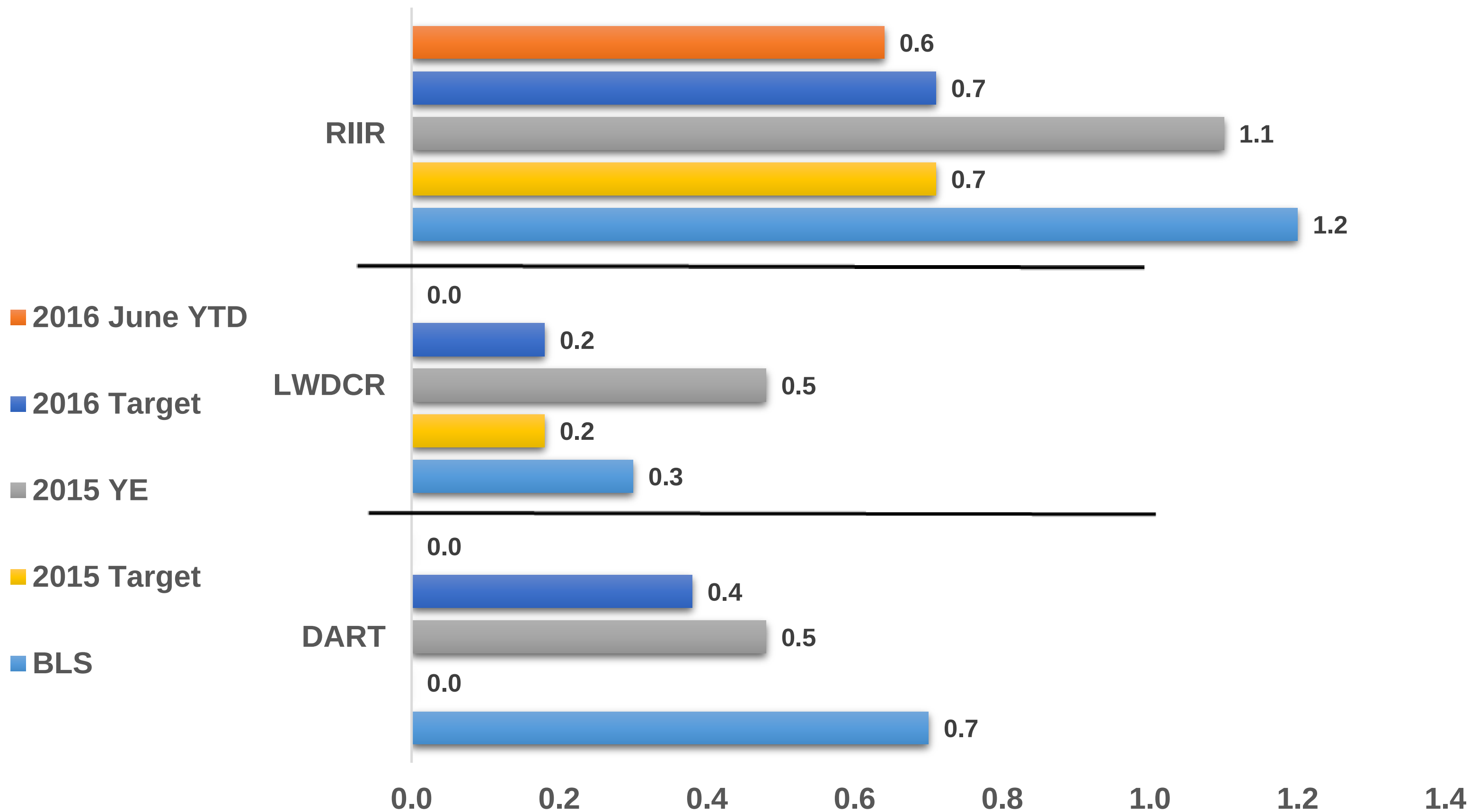
Safety Performance – Customer Service



2014 BLS - most recent data

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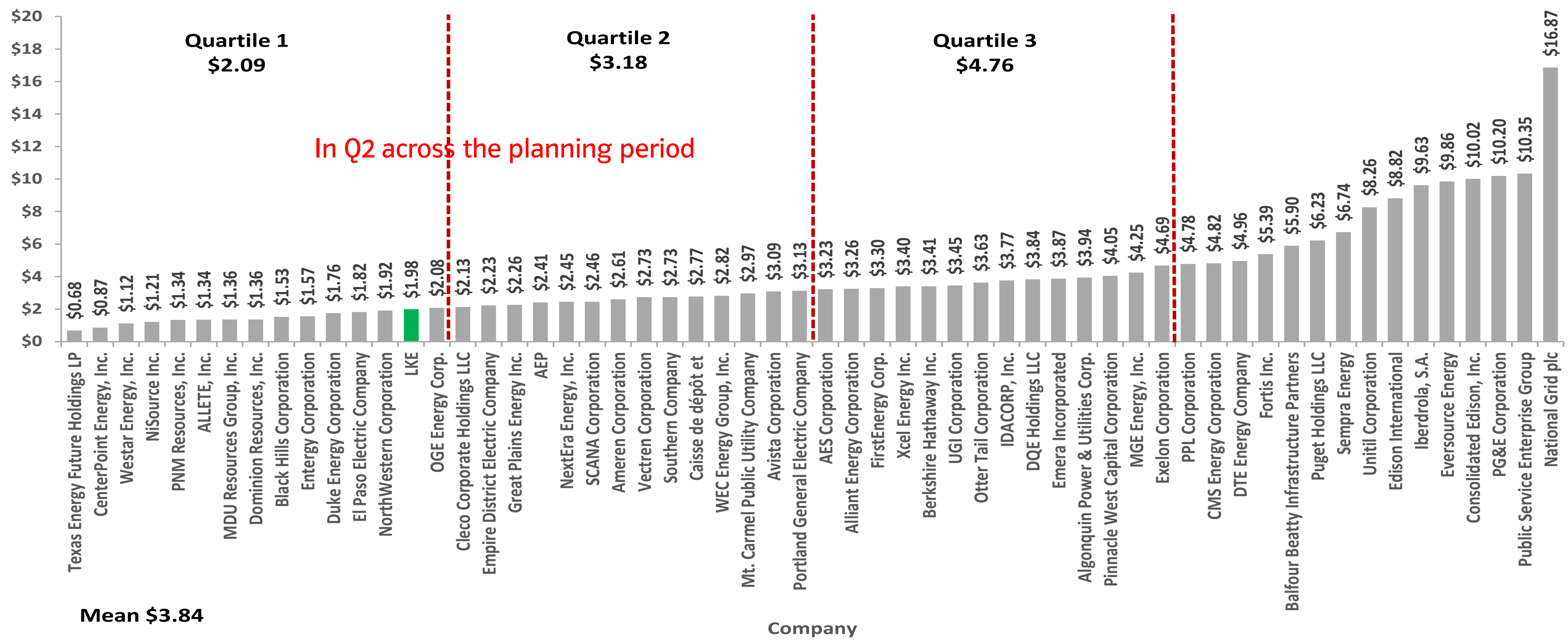
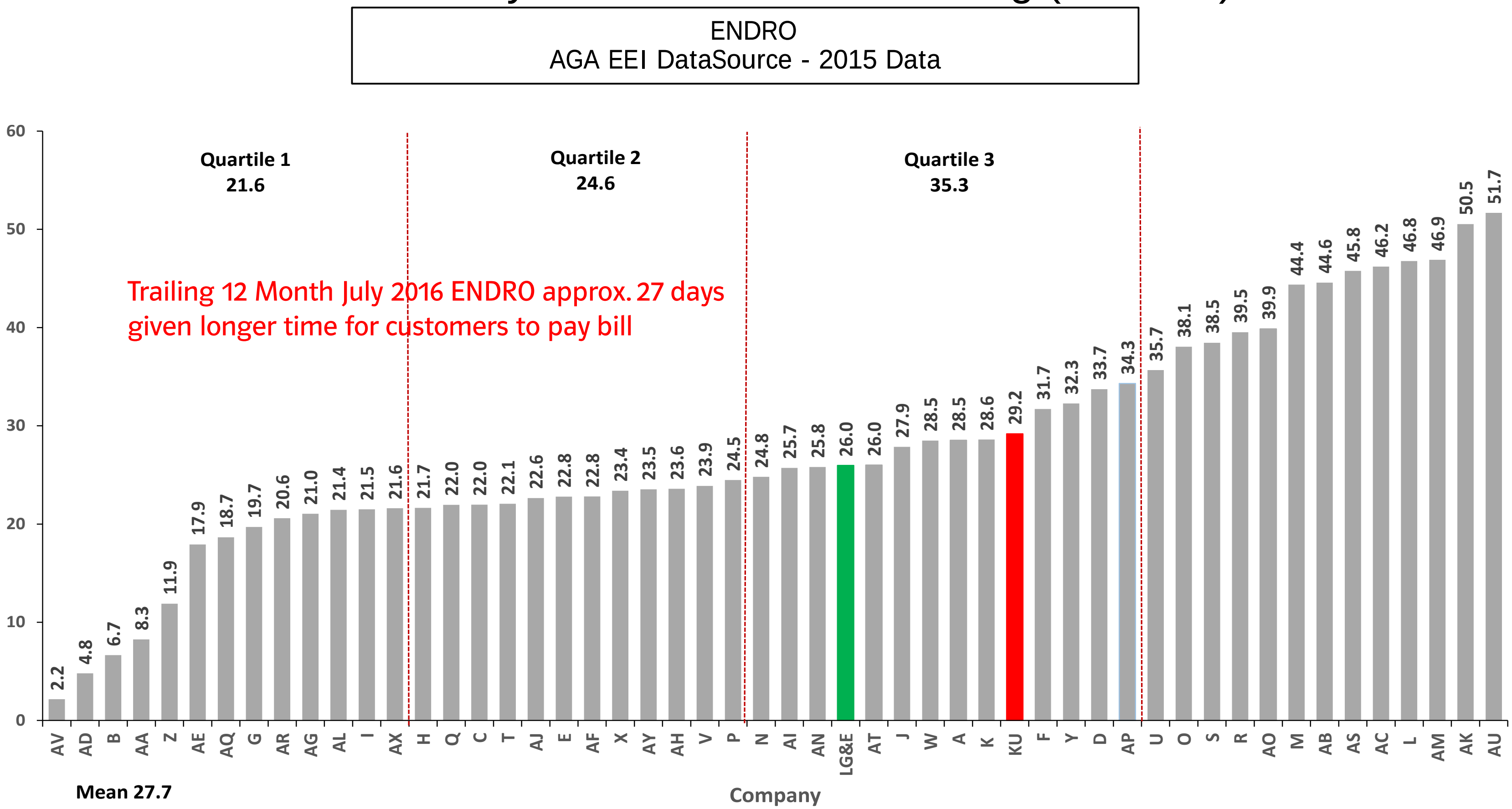
PPL companies

Total Retail Electric O&M Cost per MWh

Overall Retail Electric O&M Expenditures per MWh
FERC Utility Cost Benchmarking – 5 Year Average Data (2011-2015) (Electric Only)



Estimated Number of Days of Revenue Outstanding (ENDRO)



Note: January 2013 Rate Case granted customers more time to pay (minimum 22 calendar days vs. 12 calendar days)

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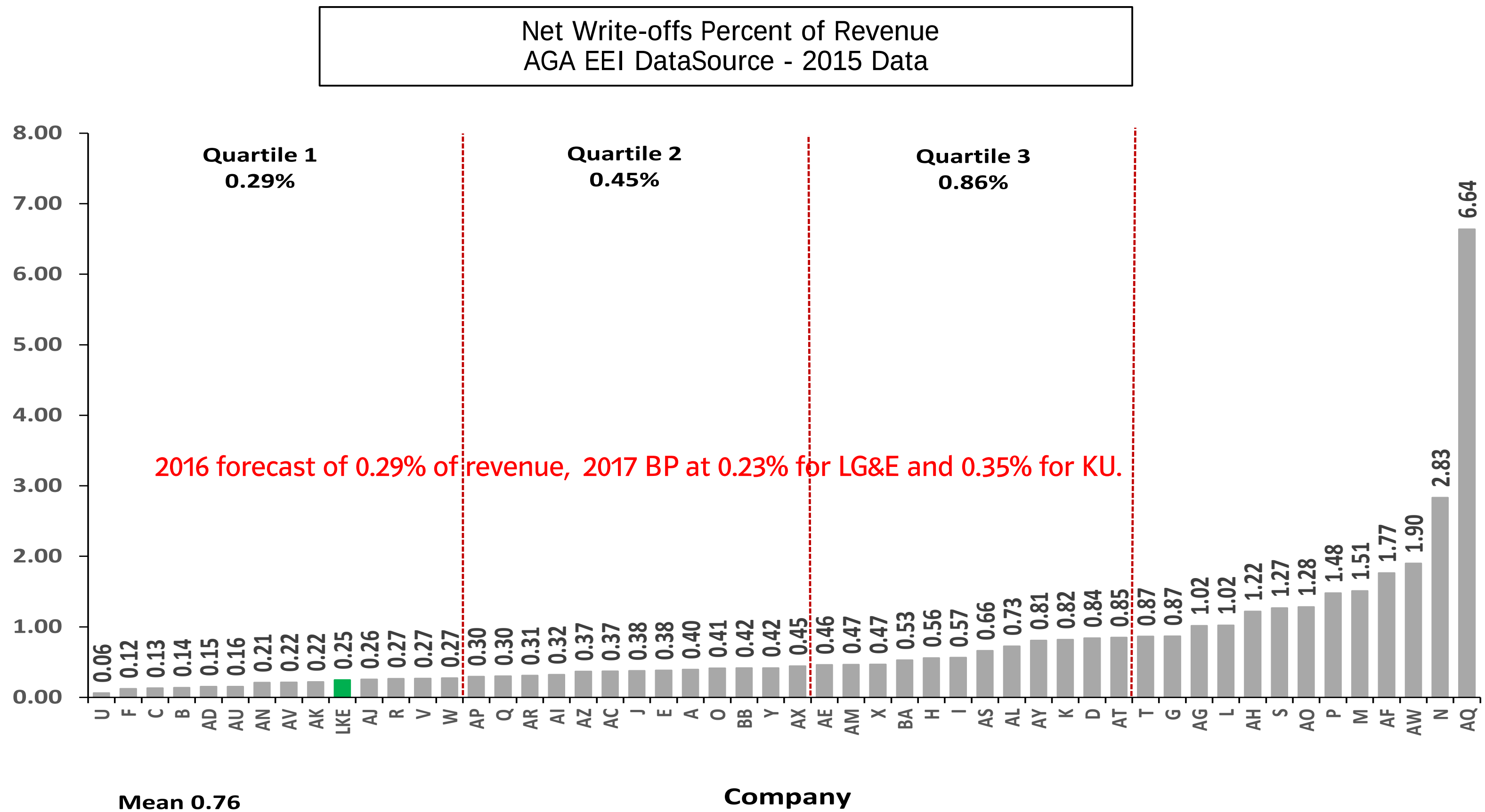
PPL companies

Net Write-Offs as a Percent of Revenues to Ultimate Customers



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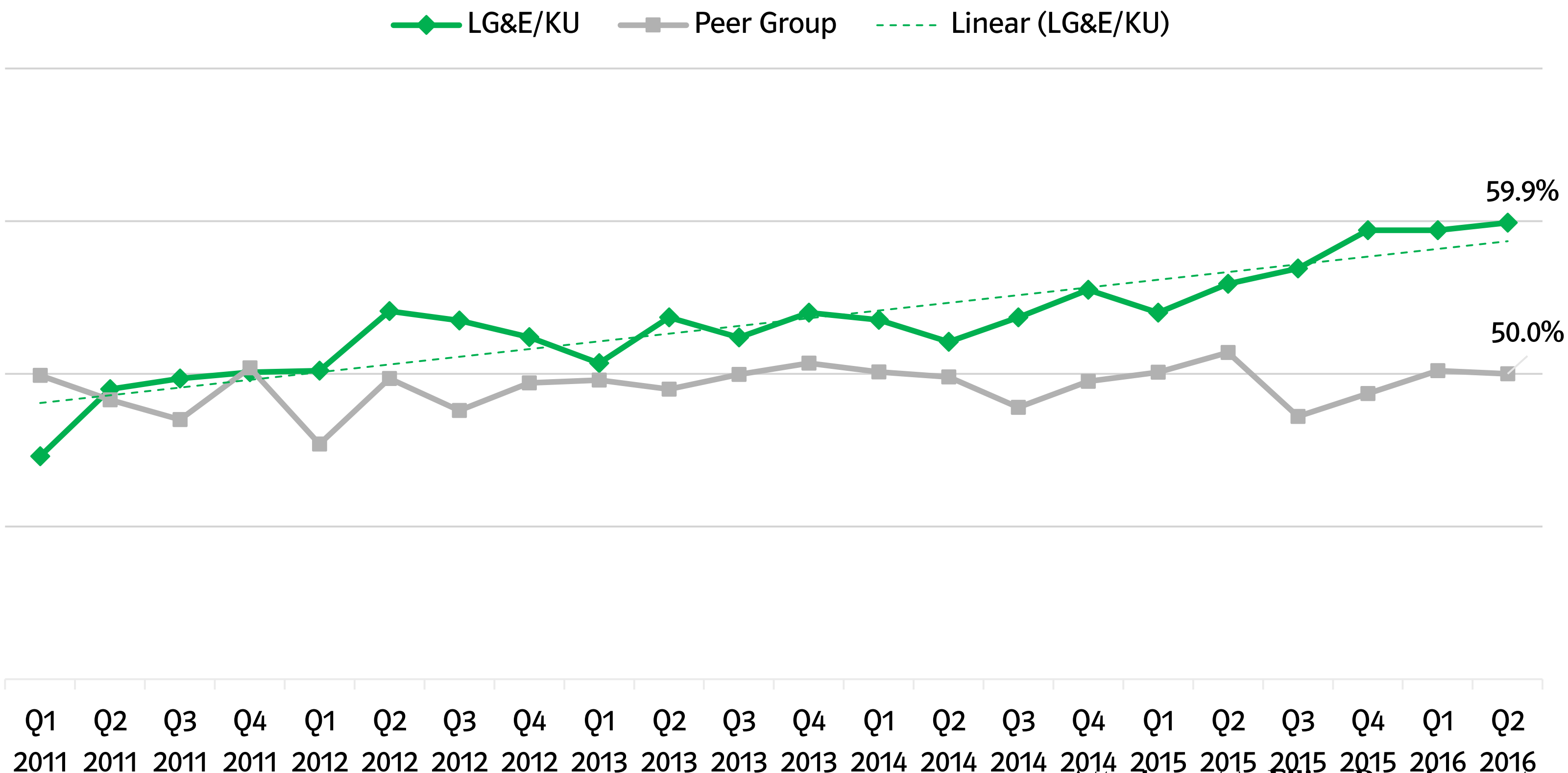
Residential Customers – Satisfaction Survey

Measured as "Top Two Box" (score of 9 or 10 on 10-point scale)



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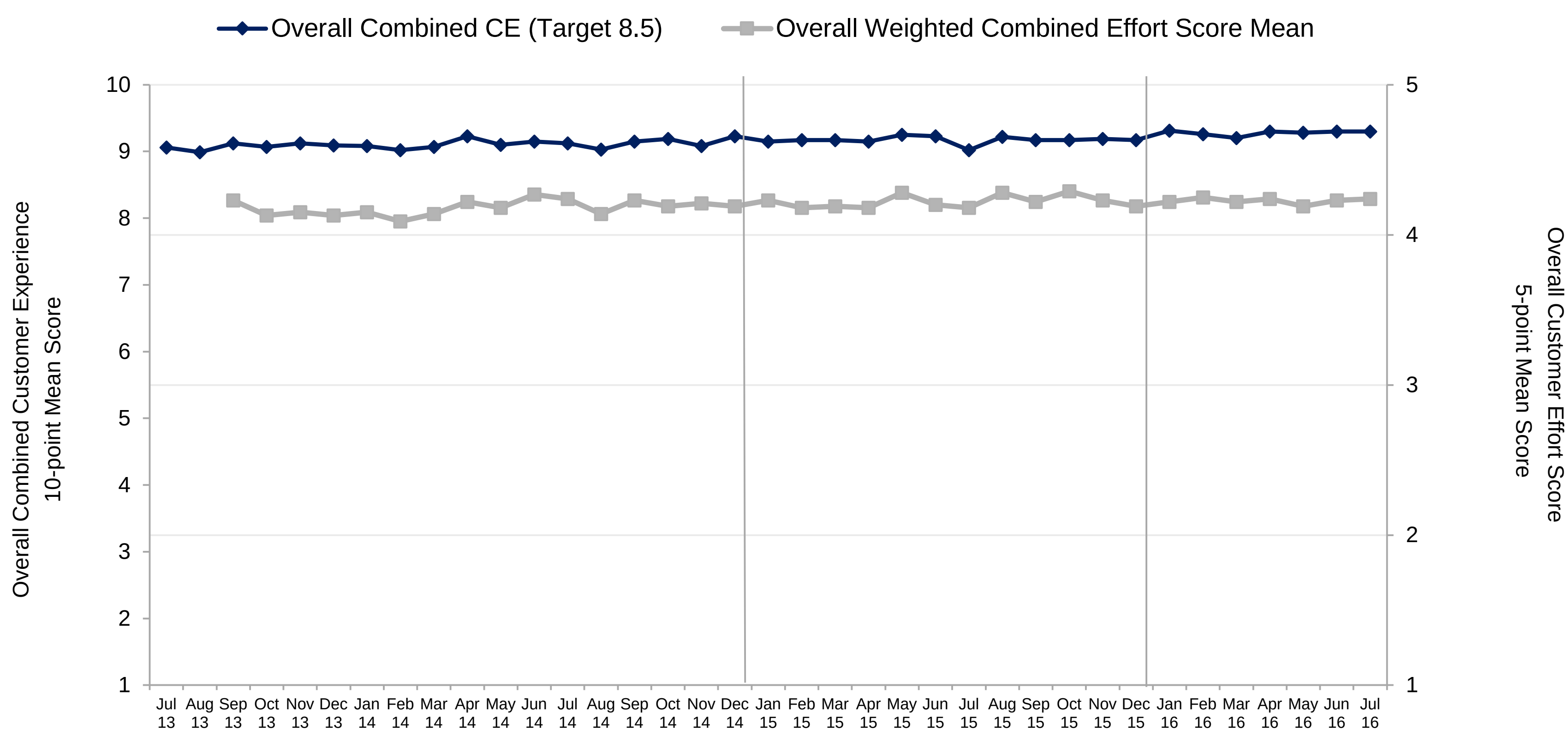
Plan Highlights

All Customer Contact Channels

Combined "Customer Experience" vs "Combined Effort" Score



Combined scores = Residential and Business agent and self serve contact channels, weighted by channel volumes.

<u>Note</u>: Residential and Business IVR transaction surveys were discontinued in 2016.

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PPL companies

- Safety and Wellness
  - *Maintain industry leading performance*
  - *Enhance operational effectiveness within the COO organization*
  - *Support the transfer of safety knowledge from seasoned to new employees*
  - *Ensure a comprehensive safety/technical training plan is in place for all employees*
  - *Continue to improve workforce, business partners and public safety*
  - *Continue to improve motor vehicle safety*
  - *Identify, share and capitalize on industry best practices*
  - *Promote wellness initiatives as an aspect of safety to ensure employees are in optimal physical condition to prevent work related illnesses and injuries*

- Customer Experience
  - *Advance corporate-wide "Customer Experience" strategy/initiative*
  - *Continue tracking new Customer Satisfaction Index in parallel to Top Two Box score on Company's residential satisfaction study*
  - *Continue investments in enhanced customer contact channels and the migration to a Corporate "Unified Communications" platform*
  - *Enhance our "Customer Advocacy" role through partnerships with customer focus groups*
  - *Continue commitment to corporate citizenship and community involvement*
  - *Continue to deliver the current portfolio of customer energy efficiency programs, including customer education on the need for energy efficiency*
  - *Advance our understanding of customer behavior while gaining insight into customer needs*

LG&E KU PPL companies

- OPEX
  - *On target in 2016 to achieve 8&4 approved forecast.*
  - *Compounded Annual Growth Rate (CAGR) from 2016-2021 (excluding clearing costs moved to Customer Services in 2017) is 1.8% in total and 1.4% without bad debt.*
  - *Major Initiatives:*
    - Customer Experience Strategy
    - Right of Way and Facility Services Document Preservation Program
    - SAP Upgrade Project
    - Full-Scale AMS Implementation, inclusive of OPEX savings
  - *Major Financial Risks:*
    - Customer Hardship and Uncollectible Accounts
    - Industry Regulatory Uncertainty

- Cost of Sales
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2016-2021 is 3.9%.*
  - — *Major Initiatives:*
    - Energy Efficiency Continuance
- Capital
  - — *On target in 2016 to achieve 8&4 approved forecast.*
  - — *Major Capital Initiatives:*
    - Full-Scale AMS Implementation
    - Energy Efficiency Programs and Services
    - Master Facility Plan Implementation
    - Gas and Electric Meters
    - SAP Upgrade Project (Capital in IT's Budget)

- AMS: The Company is implementing full scale deployment of advanced meters across the LG&E, KU, and ODP service territories beginning in July 2017 and completing on or before December 31, 2019 at a cost of $350M ($319.7M Capital, $30.3M O&M) with the following scope:
  - *Exchange 418k electric meters in LG&E territory*
  - *Exchange 561k electric meters in KU and ODP territory*
  - *Install remove telemetering equipment on 322k gas meters in LG&E territory*
  - *Deploy RF Mesh infrastructure to enable AMS RF communications network across all company territories*
  - *Update existing meter head-end to support full system volume of endpoints*
  - *Install and integrate Meter Data Management System (MDMS), Meter Asset Management (MAM), and Meter Operations Center (MOC)*
  - *Establish online portal access for customers to review usage information*

Major Assumptions

- *Costs have been included in 2017 BP, as well as associated savings benefits in Field Services and Meter Reading areas*
- *6 incremental employees are assumed to start in 2016 and early 2017.*
- *Any regulatory and internal approvals can be achieved to meet the 2017-2019 implementation schedule.*
- *Certain regulatory approvals could enhance AMS savings but are not included in the plan or reflected in the O&M savings.*
- *No regulatory and legislative action to mandate smart meter / smart grid occurs during the planning period.*

- Bad debt expense is based on .23% of projected revenues for LG&E and .35% of projected revenues for KU through the planning period.
- SAP Upgrade project in-service date is mid-2017.
  - *For the SAP Upgrade project, 26 additional FTE's are required from 2016-2018 (14 replacing employees on the project and 12 additional employees in the back office).*
- Solar fields are built starting in 2017 – 3 in 2017, 3 in 2018 and 2 in 2019.
- Energy Efficiency projects and education will continue to be an area of focus.
- The DSM budget dollars are based on the current approved levels through December 2018. 2019-2021 dollars are based upon continuing DSM at its currently level of program offerings, demand, and energy savings.
  - *Avoided cost of capacity remains consistent with historical levels. If this changes, it may affect the amount of DSM that we can economically offer.*

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	**40,608**	**39,368**	**43,546**	**43,537**	**45,042**	**46,015**	**47,168**
Non-Labor							
Bad Debt	7,440	8,376	8,980	9,437	10,001	10,320	10,601
Residential Contractors	14,156	17,754	22,572	22,607	16,059	12,366	12,592
Other Outside Services	8,706	6,432	12,308	16,462	18,193	15,618	17,032
Total Outside Services	22,862	24,186	34,880	39,069	34,252	27,984	29,624
Materials	2,168	1,819	2,099	2,028	2,001	2,040	2,081
Transportation	1,614	1,744	1,830	1,921	1,990	2,027	2,068
Postage	5,167	5,062	5,352	5,500	5,666	5,779	5,895
Other Non-Labor	3,277	3,505	5,733	5,742	5,872	5,930	6,006
Total Non-Labor	**42,528**	**44,693**	**58,874**	**63,698**	**59,782**	**54,080**	**56,275**
Total O&M Expenses	**83,136**	**84,061**	**102,420**	**107,235**	**104,824**	**100,095**	**103,443**

NOTE: Starting in January 2017, Operating Services Clearing Costs previously in Corporate are moved to Customer Services.
The 2017 amount is $10.8m.

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PPL companies

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	102,561	106,919	103,210	97,869	99,629
Drivers:					
Headcount Changes	193	199	181	164	171
Bad Debt Expense	(683)	(689)	(611)	(594)	(611)
LG&E Ctr, KUGO Rent & OpEx	458	582	663	676	690
Security & CIP Costs	143	150	212	216	221
All Other	(253)	73	1,169	1,764	3,344
Total Drivers	(142)	316	1,614	2,225	3,814
Current Plan	102,420	107,235	104,824	100,095	103,443

NOTE: The expectations each year have been adjusted to reflect the most current estimates on AMS.

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PPL companies

2015-2021 Margin Expenses / Cost of Sales ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Margin Expenses							
Mechanism Recoverable:							
DSM Costs	32,492	36,866	40,201	41,302	42,488	43,498	44,685
Bad Debt Related to GSC	301	251	250	247	243	244	248
Total Margin/Cost of Sales	32,793	37,117	40,451	41,549	42,731	43,742	44,933

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
<u>Mechanism recoverable</u>					
Plan Expectation	41,059	40,666	27,477	28,050	26,014
Drivers					
Bad Debt Expense	(108)	(117)	(126)	(132)	(210)
DSM Programs	(500)	1,000	15,380	15,824	19,129
Current Plan	40,451	41,549	42,731	43,742	44,933

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
VP Customer Services	2	2	2	2	2	2	2
Operating Services & Business Process Management	43	45	49	49	49	49	49
Revenue Integrity	216	218	220	223	225	225	225
Customer Services & Marketing	384	409	406	394	394	394	394
Energy Efficiency	20	22	29	29	29	29	28
Corporate Secuirty & Business Continuity	10	9	9	9	9	9	9
SAP Upgrade Project	2	18	0	0	0	0	0
Interns	4	4	5	5	5	5	5
TOTAL	**681**	**727**	**720**	**711**	**713**	**713**	**712**
From 2016 Business Plan		731	715	704	704	704	
Change From 2016 Business Plan		(4)	5	7	9	9	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	44	(5)	(10)	2	-	(1)
2.) Compliance – NERC, FERC, CIP, etc.	2	(2)	1			
3.) EPA/Environmental	-	-	-	-	-	-
4.) Administrative/Corporate	-	-	-	-	-	-
TOTAL	**46**	**(7)**	**(9)**	**2**	**-**	**(1)**
Contractor Offsets By Year: (New hire reducing contractor use)			3	1		

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	580	593	590	467	385	377
Contractor Change from 2016 Plan	(3)	10	8	(115)	(197)	

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LG&E KU PPL companies

Plan Risks

PPL companies

Appendix

Operational Performance

Key Performance Indicators

KPI	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Safety - Employees Incident Rate [1]	1.11	0.48	0.71	0.71	0.71	0.71	0.71
Safety - Contractors Incident Rate [1]	1.64	1.71	1.11	1.11	0.89	0.89	0.71
DART - Employees [1]	0.48	0.00	0.36	0.36	0.36	0.36	0.36
Overall Customer Experience [1]	9.17	9.29	8.50	8.50	8.50	8.50	8.50
Overall Customer Satisfaction (TIA Points) [2]	28.00	see below	18.00	18.00	18.00	18.00	18.00
LKE Service Order Days to Complete [3]	N / A	N / A	TBD	TBD	TBD	TBD	TBD
O&M Cost Per MWH Sold – 5 Yr. Avg. Calculation	1.98	2.13	2.31	2.43	2.55	2.66	2.76

[1] 2016 Column is YTD actual through August 2016.

[2] YTD actual June 2016 is 14.00.

[3] Measures the time between the scheduled date and the completed service order date (excludes credit and adjustment related service orders).

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2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	**83,136**
Labor Changes (Excluding SAP)	(1,669)
Labor - SAP Project	429
Bad Debt Expense	937
Outside Services	1,324
Other Non-Labor	(96)
2016 FC	**84,061**
Labor Changes (Excluding SAP & AMS)	1,521
Labor - SAP Project	1,243
Labor - AMS Project	1,414
Bad Debt Expense	604
Outside Services (Excluding AMS)	1,273
Outside Services - AMS Project	1,817
Clearing - Transferred to CS	10,773
Other Non-Labor	(286)
2017 Plan	**102,420**
Labor Changes (Excluding SAP & AMS)	1,585
Labor - SAP Project	(1,594)
Bad Debt Expense	458
Outside Services (Excluding AMS)	476
Outside Services - AMS Project	3,713
Other Non-Labor	177
2018 Plan	**107,235**

2018 Plan	**107,235**
Labor Changes (Excluding SAP & AMS)	1,724
Labor - SAP Project	(219)
Bad Debt Expense	564
Outside Services (Excluding AMS)	921
Outside Services - AMS Project	(5,738)
Other Non-Labor	337
2019 Plan	**104,824**
Labor Changes (Excluding SAP & AMS)	1,326
Labor - AMS Project	(353)
Bad Debt Expense	319
Outside Services (Excluding AMS)	643
Outside Services - AMS Project	(6,911)
Other Non-Labor	247
2020 Plan	**100,095**
Labor Changes (Excluding SAP & AMS)	1,380
Labor - AMS Project	(227)
Bad Debt Expense	281
Outside Services (Excluding AMS)	771
Outside Services - AMS Project	869
Other Non-Labor	274
2021 Plan	**103,443**

LG&E KU PPL companies

2015-2021 Walk Forward for GMEXP / Cost of Sales ($000)

2015 Actual	**32,793**
Bad Debt Related to GSC	(50)
DSM escalation of continuing programs & inclusion of KSBA	4,374
2016 FC	**37,117**
Bad Debt Related to GSC	(1)
DSM escalation of continuing programs & inclusion of KSBA	3,335
2017 Plan	**40,451**
Bad Debt Related to GSC	(3)
DSM escalation of continuing programs	1,101
2018 Plan	**41,549**
Bad Debt Related to GSC	(5)
DSM escalation of continuing programs	1,186
2019 Plan	**42,730**
Bad Debt Related to GSC	2
DSM escalation of continuing programs	1,010
2020 Plan	**43,742**
Bad Debt Related to GSC	3
DSM escalation of continuing programs	1,188
2021 Plan	**44,933**

PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of August 2016)	**715**	**580**
Operating Services & Business Process Mgmt	1	
Revenue Integrity	2	
Customer Services & Marketing	8	
SAP Upgrade Project	1	
2016 Headcount FC - Year End	**727**	**580**
Operating Services & Business Process Mgmt	4	
Revenue Integrity	2	13
Customer Services & Marketing	(3)	
Customer Energy Efficiency	7	
SAP Upgrade Project	(18)	
Interns	1	
2017 Headcount Plan	**720**	**593**

	Company Employees	Resident Contractors
2017 Headcount Plan	**720**	**593**
Revenue Integrity	3	(3)
Customer Services & Marketing	(12)	
2018 Headcount Plan	**711**	**590**
Revenue Integrity	2	(123)
2019 Headcount Plan	**713**	**467**
Revenue Integrity	0	(82)
2020 Headcount Plan	**713**	**385**
Revenue Integrity	0	(8)
Customer Energy Efficiency	(1)	
2021 Headcount Plan	**712**	**377**

LG&E KU
PPL companies

2015-2021 Other Balance Sheet Costs ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Clearing Costs							
Labor							
Non labor	10,093	10,400	10,852	11,195	11,484	11,652	11,822
Total	10,093	10,400	10,852	11,195	11,484	11,652	11,822
Local Engineering							
Labor	63	229	312	318	326	334	343
Non labor	1	4	6	6	6	6	6
Total	64	233	318	324	332	340	349
Total Other Costs	10,157	10,633	11,170	11,519	11,816	11,992	12,171

Note : The "Clearing Costs" shown above include the allocation to Capital Corp. The amounts included in the O&M expenses on other slides are amounts allocated to LG&E and KU only.

LG&E KU PPL companies

LG&E KU

PPL companies

Transmission

2017 Business Plan

September 2016

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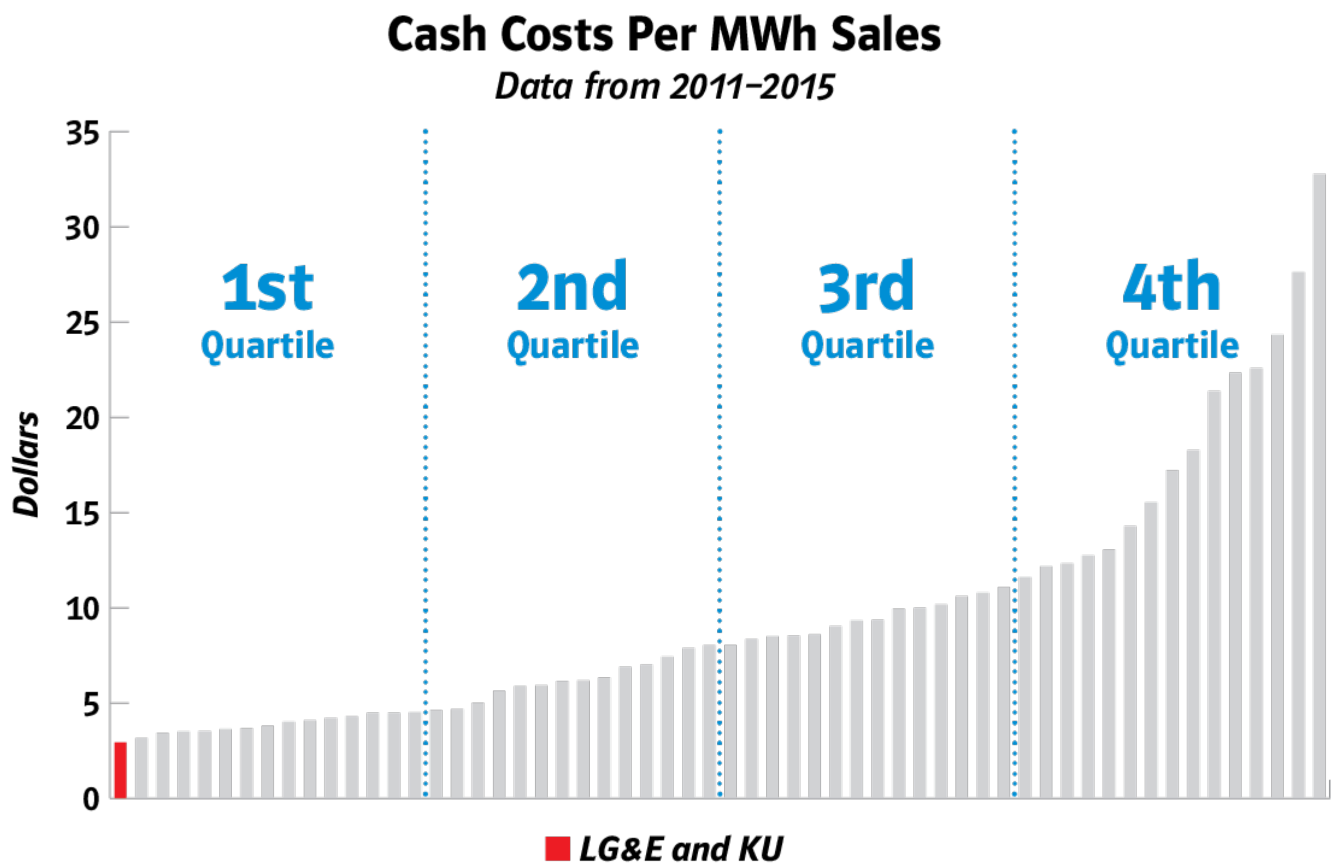
Plan Highlights

1. The 2017-2021 Transmission Business Plan will continue a strong culture of safety, performance, and regulatory compliance, with a focus on improving system reliability, resiliency and asset condition at a fair and reasonable cost.
2. Improve and sustain high reliability performance by reducing outage frequency and duration through analysis of historical performance and implementation of targeted improvement programs:
   i. Prioritized installation of sectionalizing circuit breakers and remotely controlled line switches to reduce exposure of customers to outages and speed restoration time for customers when outages occur.
   ii. Detailed assessments of lines needing improvement to identify and implement actions to reduce outages
   iii. Enhanced vegetation management programs including identification and removal of hazard trees, cycle based clearing of transmission line corridors, and widening of maintained areas around targeted lines.
   iv. Targeted replacement of assets based on age, condition and performance criteria to include wood structures, insulators, static lines, certain underground lines, relays, control houses, circuit breakers and other equipment.
3. Transmission line and substation projects approved by the Independent Transmission Organization (ITO) driven by NERC planning standards and LKE system planning guidelines to ensure electric grid adequacy to reliably serve forecasted customer demand.
4. Transmission line extensions to serve new distribution substations for retail customers.
5. Initiatives related to cyber security protection, the Energy Management System and compliance with NERC requirements.
6. Security initiatives including the protection of critical facilities from physical attacks and vandalism.
7. Resiliency initiatives to improve recoverability from catastrophic events.
8. Workforce improvements including increased engineering and project management to support reliability programs and to improve balance between contractors and employees.

Plan Highlights

FERC Benchmarking Data



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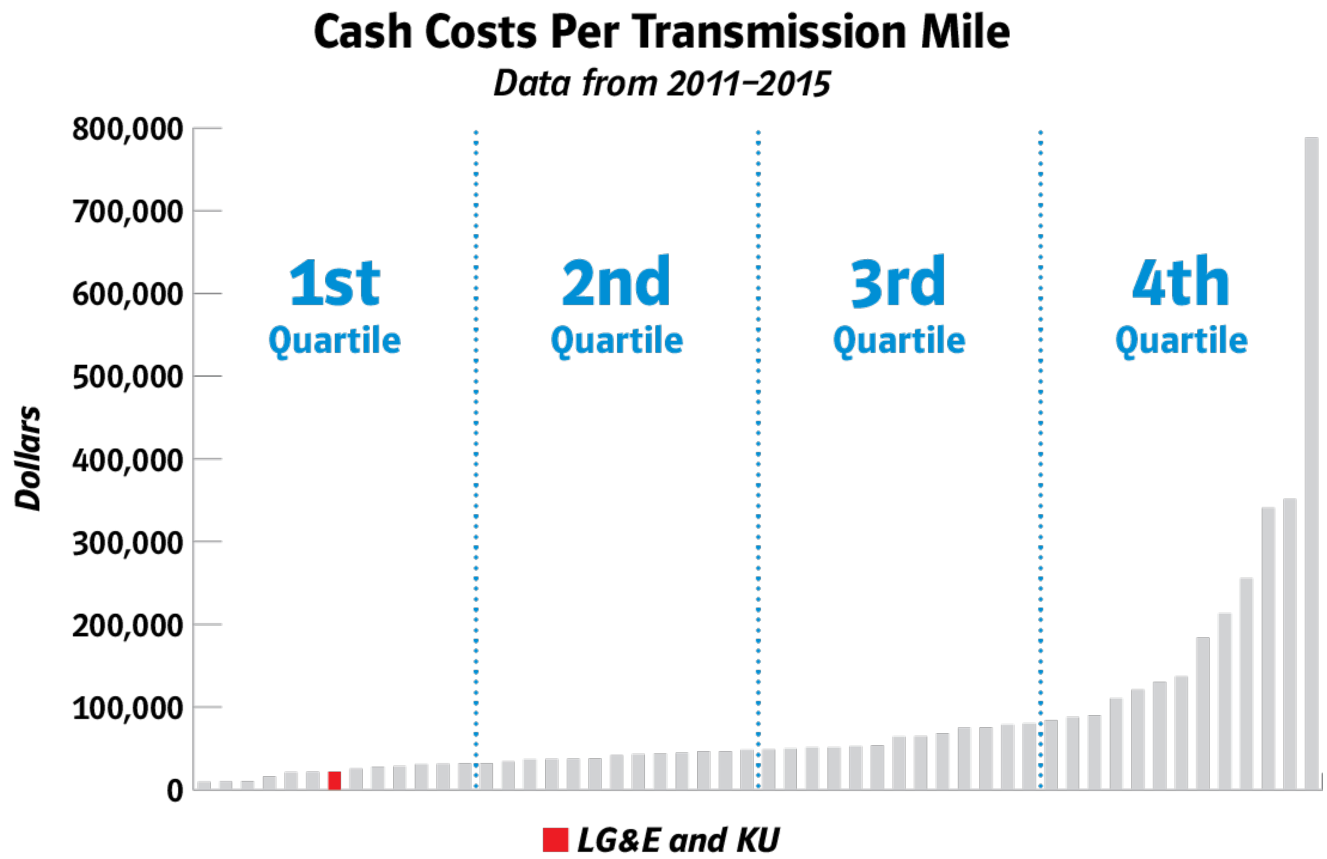
Plan Highlights

FERC Benchmarking Data



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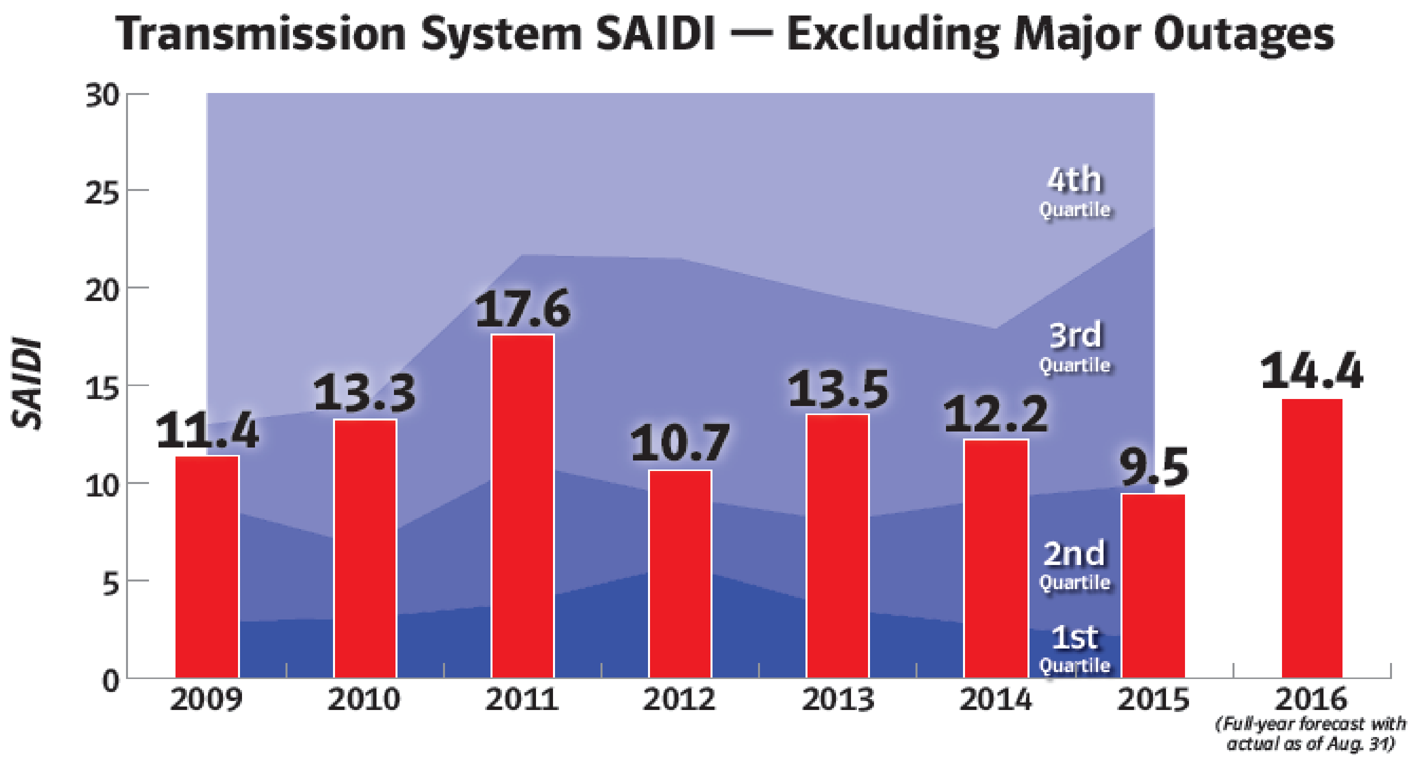
LG&E KU PPL companies

Plan Highlights

Historical Reliability Performance



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Major Assumptions

Reliability, Operations and Asset Management:

1. The strategy to improve reliability is based on historical performance and addressing line segments on a prioritized basis:
   i. Segmenting circuits with breakers and switches to reduce customer exposure from sustained outages and improve restoration time.
   ii. Rebuilding/restoring certain line segments based on performance and condition.
   iii. Enhanced vegetation clearing will reduce sustained and momentary outages:
      - Line clearing will transition from a largely inspection based program to a 5 year maintenance cycle for all lines 69kV and higher.
      - A hazard tree identification and removal program.
2. Enhanced transmission asset management will effectively improve and maintain high performance and reliability of the assets over time:
   i. Structure, cross arm and insulator replacements based on condition determined by detailed inspections.
   ii. Static wire replacements based on age and lightning performance.
   iii. Control house and related protection and control replacements based on age, condition and performance.
   iv. Circuit breaker replacements based on age, condition and maintainability.
   v. Transmission switch maintenance to include routine inspections and operation will reduce outages and ensure operability.
   vi. Extend life of tower and substation structural steel through condition assessment and enhanced maintenance including corrosion prevention and control.
   vii. Optimize asset lifecycle of substation equipment including circuit breakers and transformers through diagnostics.
3. Storm damage costs are based on a 10 year average.

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Major Assumptions

Transmission Expansion Plan (TEP) and Native Load:

1. Projects are based on the most recent customer demand forecasts and it is assumed that the Independent Transmission Organization (ITO) will approve the 2017 TEP without significant revisions.

2. A new, 12.5 mile 345kV line will be required by summer 2021 between Trimble County substation and Clifty Creek substation due to increased external power flows.

3. The TEP includes funding for rating increases to certain transmission lines based on estimates. Detailed costs will be developed after surveying and subsequent analyses are completed.

4. No funding needed to accommodate new long term, firm transmission service requests that have not already been requested or studied.

5. Connection costs for native load are coordinated with the Electric Distribution planning requirements.

6. The Clean Power Plan will not result in significant transmission improvements during the plan period.

Major Assumptions

Regulatory and Compliance:

1. The verification of line ratings on all lines above 100kV will be complete and ongoing LiDAR surveys of these lines will continue on a 6 year cycle to coincide with regulatory inspections. Ongoing inspections will not result in material expenditures.

2. FERC will approve the proposed geomagnetic disturbance (GMD) standard without significant revisions and the required assessment of the system for impact from a GMD disturbance will not result in risks requiring material expenditures to mitigate.

3. Additional revisions to NERC Reliability standards will not require material incremental expenditures beyond what is funded in this plan.

4. One substation is within scope of the 2015 CIP- 014 requirement for substation physical security. It is assumed that NERC will not modify CIP-014 during the plan period.

5. Regional and interregional planning processes as required by FERC Order 1000 will not result in material capital or O&M expenditures.

Major Assumptions

Open Access Transmission Tariff (OATT) Revenue and Cost of Sales:

1. OATT transmission revenues are based on the following:

   i. Customer provided load forecasts have been evaluated and adjusted, based on historical performance, to reflect their expected coincident peak billing amount.

   ii. OATT rate forecast is based on 2015 FERC Form 1 data, the FERC approved rate formula, and 2017 Business Plan projections, including O&M and capital.

   iii. [redacted] will renew 104 MWs of point-to-point transmission service for the term August 2017 – September 2022. It is assumed that [redacted] will retire [redacted] Unit #1 in 2019 and not renew the remaining 156 MWs of current long term point-to-point service.

2. Cost of Sales assume the following:

   i. MISO transmission rates for 2017-2021 are adjusted at the same annual rate of change as the forecasted LG&E/KU OATT transmission rates.

   ii. Cost of credits for wholesale customers eligible for de-pancaked rates are based on Transmission Service Requests submitted by these customers – 20 MWs for 2017-2018, 200 MWs starting in May 2019, and 300 MWs in May 2022.

   iii. TranServ will continue as the ITO service provider at costs based on the existing agreement.

   iv. TVA will remain as the Reliability Coordinator (RC) at costs based on the existing agreement.

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	12,960	12,626	12,763	13,133	13,193	13,445	13,793
Non labor							
345kV-500kV Line Clearing	1,465	1,306	2,606	3,755	3,118	2,837	3,267
69kV-161kV Line Clearing	4,394	5,327	6,416	8,990	10,130	10,248	10,515
Hazard Tree Program	-	-	594	1,188	1,188	1,188	1,188
Switch Maintenance	-	-	300	834	859	885	912
Pole/Tower Corrosion Prevention	-	-	400	600	769	1,000	1,025
Storm Restoration	707	454	425	431	438	444	451
Lines Other	1,877	1,871	2,286	2,471	2,379	2,409	2,440
Substations and Protection	4,937	4,254	4,462	4,466	4,537	4,622	4,688
System Operations & Compliance	2,734	2,506	2,931	2,898	2,979	3,162	3,150
Planning, Tariffs and Reliability Perf.	630	675	799	814	831	848	867
All Other Non labor	217	586	441	433	463	449	418
Total OPEX Expense	**29,921**	**29,605**	**34,423**	**40,013**	**40,884**	**41,537**	**42,714**

LG&E KU PPL companies

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	34,319	39,627	40,776	41,086	41,829
Drivers:					
Labor	104	386			
345kV Line Clearing			108	451	885
Current Plan	34,423	40,013	40,884	41,537	42,714

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2015-2021 Revenues
($000)

OATT Revenues

	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
2017 BP							
Wholesale Customer OATT*	5,981	6,453	7,031	7,382	3,775	2,045	2,292
3rd Party OATT Revenue	19,339	22,764	23,212	24,717	26,238	27,313	29,173
3rd Party Other Municipal Revenue	-	-	239	366	5,438	8,478	9,409
Joint Party Settlement	-	-	974	832	832	832	69
Total OATT Revenue	25,320	29,217	31,456	33,297	36,283	38,668	40,943
2016 BP							
Wholesale Customer OATT*		6,556	6,665	7,015	3,552	2,008	2,217
3rd Party OATT Revenue		22,365	22,728	22,609	24,869	27,590	29,983
3rd Party Other Municipal Revenue		44	340	515	6,088	9,476	10,314
Joint Party Settlement		-	-	-	-	-	-
Total OATT Revenue		28,965	29,733	30,139	34,509	39,074	42,514
Variance, Fav / (Unfav)		252	1,723	3,158	1,774	(406)	(1,571)

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2015-2021 Margin Expenses / Cost of Sales ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Margin Expenses							
All other Cost of Sales:							
TranServ - ITO	2,722	2,792	2,705	2,534	2,571	2,609	2,648
TVA - RC	2,391	2,439	2,487	2,537	2,588	2,640	2,692
Misc Transmission Expense	7,985	8,629	10,098	10,595	17,652	21,118	21,647
Total Margin/Cost of Sales	13,098	13,860	15,290	15,666	22,811	26,367	26,987

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2017-2021 Margin/Cost of Sales Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Other Non-Mechanism					
Plan Expectation	14,575	15,354	22,542	26,989	27,529
Drivers					
TranServ - ITO	(115)	(356)	(390)	(424)	(446)
Misc Transmission Exp	830	668	659	(198)	(96)
Current Plan	15,290	15,666	22,811	26,367	26,987

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2017-2021 Net Margin
($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
2016 - 2020 Business Plan	15,158	14,785	11,967	12,085	14,985
Wholesale Customer OATT*	366	367	223	37	75
3rd Party OATT Revenue	484	2,108	1,369	(277)	(810)
3rd Party Other Municipal Revenue	(101)	(149)	(650)	(998)	(905)
Joint Party Settlement	974	832	832	832	69
Other Miscellaneous Trans Exp	(830)	(668)	(659)	198	95
RC and ITO Expense	115	356	390	424	446
2017 - 2021 Business Plan	16,166	17,631	13,472	12,301	13,956

*Wholesale Customer OATT denotes transmission component revenue associated with the full requirement municipal contracts administered by the Energy Supply & Analysis Department

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2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Lines	**32**	**33**	**34**	**34**	**35**	**35**	**35**
Substation Eng, Maint. and Construct.	**19**	**19**	**21**	**21**	**21**	**21**	**21**
Protection & Control	**25**	**26**	**28**	**28**	**28**	**28**	**28**
Project Management	**0**	**2**	**4**	**5**	**5**	**5**	**5**
System Operations	**41**	**39**	**40**	**39**	**36**	**36**	**36**
EMS	**9**	**8**	**8**	**9**	**8**	**8**	**8**
Strategy & Planning	**14**	**15**	**15**	**15**	**15**	**15**	**15**
Policy & Tarrifs	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Reliability & Performance Standards	**4**	**5**	**6**	**6**	**6**	**6**	**6**
Compliance	**3**	**3**	**2**	**2**	**2**	**2**	**2**
Senior Managers	**4**	**4**	**5**	**5**	**5**	**5**	**5**
Interns	**7**	**8**	**9**	**8**	**8**	**8**	**8**
TOTAL	**161**	**165**	**175**	**175**	**172**	**172**	**172**
From 2016 Business Plan		165	172	173	173	173	
Change From 2016 Business Plan		0	3	2	-1	-1	

Year to Year Increases (Decreases)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1.) Maintenance /Operational	4	10	0	-3	0	0
2.) Compliance – NERC, FERC, CIP, etc.	0	0	0	0	0	0
3.) EPA/Environmental	0	0	0	0	0	0
4.) Administrative/Corporate	0	0	0	0	0	0
TOTAL	**4**	**10**	**0**	**-3**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)	**2**	**3**				

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	237	292	350	406	406	419
Contractor Change from 2016 Plan	14	(55)	(1)	33	33	

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Plan Risks

1. Revised regulations may materially increase investments and expenses.
2. Regional changes to the transmission grid topology, location and mix of generation resources, the Clean Power Plan, and other factors may result in power flows that drive the need for significant additional infrastructure investments.
3. Detailed study of the need and alternatives to the Trimble County to Clifty Creek 345kV line could result in other alternatives including elimination or delay of the project.
4. System conditions (weather, external grid configuration and loop flows, generation status, etc.) may delay or alter outages required to complete construction.
5. BES LiDAR surveying could result in additional required capital projects to resolve issues identified.

Appendix

Operational Performance

Key Performance Indicators

KPI	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Recordable Injury Incident Rate - Employees	0.00	0.00	0.62	0.62	0.62	0.62	0.62
Recordable Injury Incident Rate - Contractors	1.87	2.16	1.98	1.95	1.91	1.88	1.84
Days Away from work, Restriction, or Transfer - Employees		0.00	0.62	0.62	0.62	0.62	0.62
Annual SAIDI (minutes)	9.5	14.4	11.0	10.5	10.1	9.7	9.0
SAIDI 5 Year Average (minutes)	12.7	12.0	12.1	11.5	11.1	11.1	10.1
SAIDI 5 Year Average Including Major Event Days (minutes)	19.2	18.8	18.4	18.5	17.2	17.7	16.6
Cash Cost / MWh	$2.93	$3.37	$3.81	$4.19	$4.78	$5.23	$6.58
Cash Cost / Mile	$21,650	$24,410	$27,340	$29,930	$33,550	$36,450	$45,460

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2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	29,921
Labor	(334)
System Improvement (Line Clearing)	774
Storm Restoration	(253)
All Other	(503)
2016 FC	29,605
Labor	137
System Improvement (Line Clearing)	2,983
System Improvement (Switch Maintenance and Structure Protective Coatings)	700
FERC Audit Preparation	100
Testing of Underground Transmission System	165
All Other	733
2017 Plan	34,423
Labor	370
System Improvement (Line Clearing)	4,317
System Improvement (Switch Maintenance and Structure Protective Coatings)	734
FERC Audit Preparation	(100)
All Other	269
2018 Plan	40,013
Labor	60
System Improvement (Line Clearing)	503
System Improvement (Switch Maintenance and Structure Protective Coatings)	194
All Other	114
2019 Plan	40,884
Labor	252
System Improvement (Line Clearing)	(162)
System Improvement (Switch Maintenance and Structure Protective Coatings)	257
FERC Audit Preparation	100
All Other	206
2020 Plan	41,537
Labor	348
System Improvement (Line Clearing)	697
System Improvement (Switch Maintenance and Structure Protective Coatings)	52
FERC Audit Preparation	(100)
All Other	180
2021 Plan	42,714

2015-2021 Walk Forward for GMEXP / Cost of Sales ($000)

2015 Actual	13,098
TranServ - ITO	70
TVA - RC	48
Misc Transmission Expense	644
2016 FC	13,860
TranServ - ITO	(87)
TVA - RC	49
Misc Transmission Expense	1,469
2017 Plan	15,290
TranServ - ITO	(171)
TVA - RC	50
Misc Transmission Expense	497
2018 Plan	15,666
TranServ - ITO	37
TVA - RC	51
Misc Transmission Expense	7,057
2019 Plan	22,811
TranServ - ITO	38
TVA - RC	52
Misc Transmission Expense	3,466
2020 Plan	26,367
TranServ - ITO	39
TVA - RC	52
Misc Transmission Expense	529
2021 Plan	26,987

LG&E KU
PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of August 2016)	157	227
Engineers	5	
Project Management	1	2
ESC Backfill		
Protection Team Lead	1	
Overhead Lines		13
Line Clearing		5
Inspectors		1
Other	1	0
2016 Headcount FC - Year End	165	248
Inspectors	1	8
Drafter	1	-1
PowerBase Admin	1	-1
Engineers	3	
Project Management	2	
ESC Backfill	1	
Overhead Lines		20
Line Clearing		16
Design Engineers		2
Other	1	0
2017 Headcount Plan	175	292

	Company Employees	Resident Contractors
2017 Headcount Plan	175	292
EMS Administrator	1	
Intern	-1	
Overhead Lines		40
Line Clearing		10
Inspectors		5
Design Engineers	0	3
2018 Headcount Plan	175	350
System Coordinator Retirements	-3	
Asset Management	1	
EMS Administrator Retirement	-1	
Overhead Lines		45
Line Clearing		5
Inspectors		4
Design Engineers	0	2
2019 Headcount Plan	172	406
Overhead Lines	0	0
2020 Headcount Plan	172	406
Overhead Lines		10
Line Clearing		2
Inspectors	0	1
2021 Headcount Plan	172	419

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2015-2021 Other Balance Sheet Costs ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Local Engineering							
Labor	6,964	7,145	7,793	8,367	8,601	8,931	9,178
Non labor	1,113	1,847	1,749	1,785	1,820	1,857	1,894
Total	8,077	8,993	9,542	10,152	10,421	10,789	11,072
Total Other Costs	8,077	8,993	9,542	10,152	10,421	10,789	11,072

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Generation Services

2017 Business Plan

September 2016

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- Financial Performance
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  - *Headcount*
- Plan Risks
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Plan Highlights

- New CIP compliance requirements are addressed
- Continued CCR activities are included in the plan
- No new programs or support for ELG have been included
- R&D consolidation of the EPRI programs will continue to be a challenge as other departments request services but are unable to supply funding
- All other existing programs within Generation Services will continue but expanding services and new services are impacted by labor prioritization
- Funding for 5 contractors included

Major Assumptions

- Environmental rules such as CCR, ELG and MATS will increase demand for support for the Generation Services team
- Analysis demands on System Lab may increase (environmental regulations)
- CIP versions 5 and 6 will be in effect at all generating stations and Legacy rules will continue to require more stringent test protocols
- The new SharePoint site has been implemented and will continue to be integrated throughout the fleet. The site has been developed as an essential tool and provides the site users real time data, financial analysis, reports and training information for every day usage
- Increased emphasis on Equipment Reliability (data analytics), Predictive Maintenance techniques and Welding Quality Management

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	5,721	5,974	5,850	6,044	6,151	6,341	6,739
Research and Development	2,790	4,746	5,522	6,049	6,246	6,431	6,564
High Energy Piping & Corrosion Fatigue	2,233	1,233	1,500	3,652	2,434	1,545	1,325
Civil Work (Ash Ponds, Landfills, CCR, CII)	247	1,044	759	744	697	727	714
Fuel Handling	168	234	212	216	221	225	230
Boiler Reliability	26	187	65	62	64	66	68
Mercury Monitoring	105	118	129	129	131	134	136
Other Non-Labor	1,815	1,597	2,051	2,210	1,940	2,067	2,159
Total O&M Expense	**13,105**	**15,133**	**16,088**	**19,106**	**17,884**	**17,536**	**17,935**

LG&E KU
PPL companies

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	16,092	19,065	17,868	17,568	17,975
Drivers:					
Other	(4)	41	16	(32)	(40)
Current Plan	16,088	19,106	17,884	17,536	17,935

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Director	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Generation Engineering	**26**	**26**	**26**	**26**	**26**	**26**	**27**
System Lab	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Compliance and Doc Management	**9**	**9**	**9**	**9**	**9**	**9**	**10**
Drafters	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Research and Development	**3**	**4**	**4**	**4**	**4**	**4**	**4**
Engineering Coops	**6**	**7**	**6**	**6**	**4**	**4**	**4**
TOTAL	**60**	**62**	**61**	**61**	**59**	**59**	**61**
From 2016 Business Plan		65	66	66	67	68	
Variance to 2016 Business Plan		-3	-5	-5	-8	-9	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational						
2.) Compliance – NERC, FERC, CIP, etc.						1
3.) EPA/Environmental						
4.) Administrative/Corporate	2	-1		-2		1
TOTAL	**2**	**-1**	**0**	**-2**	**0**	**2**
Contractor Offsets By Year: (New hire reducing contractor use)						**-1**

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	5	5	5	5	5	4
Contractor Variance to 2016 Plan	0	0	0	0	0	

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Plan Risks

- CIP changes over the course of the plan may be more stringent than anticipated and require a more aggressive implementation strategy
- New environmental requirements regarding Clean Power Plan were not contemplated in this plan
- CCR regulatory inspections will challenge the current civil staff and the support of the generating fleet
- Laboratory testing for new environmental rules will increase during the plan

Appendix

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	**13,105**
Wage increases and additional headcount	253
Research and Development (including EPRI transfer from other orgs)	1,956
High Energy Piping and Corrosion Fatigue	(1,000)
Dam Impoundment, Other	819
2016 FC	**15,133**
Energy Storage Amortization	500
High Energy Piping and Corrosion Fatigue	273
Consulting, Boiler Reliability, Other	182
2017 Plan	**16,088**
High Energy Piping and Corrosion Fatigue	2,152
Research and Development	527
Consulting, Boiler Reliability, Other	339
2018 Plan	**19,106**
High Energy Piping and Corrosion Fatigue	(1,218)
Consulting, Research and Development, Other	(4)
2019 Plan	**17,884**
High Energy Piping and Corrosion Fatigue	(889)
Wage Increases	189
Consulting, Research and Development, Other	352
2020 Plan	**17,536**
Wage increases and additional headcount	398
High Energy Piping and Corrosion Fatigue	(220)
Consulting, Research and Development, Other	221
2021 Plan	**17,935**

PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of July 2016)		
Electrical Engineering Group Leader	1	
2016 Headcount FC - Year End	**62**	**5**
2017 Headcount Plan	**61**	**5**
2018 Headcount Plan	**61**	**5**
Engineering Coop	(2)	
2019 Headcount Plan	**59**	**5**
2020 Headcount Plan	**59**	**5**
CIP	1	(1)
Civil Engineer	1	
2021 Headcount Plan	**61**	**4**

2015-2021 Other Balance Sheet Costs ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Other Balance Sheet							
Labor							
Non labor (Energy Storage Acct 188)	73	2,501					
Total							
Total Other Costs	73	2,501	-	-	-	-	-

PPL companies

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Energy Supply and Analysis

2017 Business Plan

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Plan Highlights

Major Assumptions

	2015 Actual	2016 Budget	8+4 2016 Forecast	2016 BP 2017	2017 Business Plan 2017	2018	2019	2020	2021
OSS Margin before Transmission Exp.	7,984	5,504	1,646	4,423	2,754	3,395	5,387	6,227	6,613
Transmission Expense (Internal)	1,282	1,139	588	1,103	1,045	1,183	1,734	1,847	1,885
Total OSS Margin at 100%	6,702	4,365	1,058	3,320	1,709	2,212	3,653	4,380	4,728
Total OSS Margin LKE Share	5,750	1,091	301	830	419	542	897	1,077	1,161
Off-system Sales Volume-GWh									
On-peak	256	163	104	152	163	165	232	242	229
Off-peak	52	40	14	36	19	26	43	61	74
Weekend	78	119	32	130	61	100	157	154	177
Total	386	322	150	318	243	291	432	457	480

LG&E KU PPL companies

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	8,098	7,690	7,713	7,853	8,033	8,305	8,512
Outside Services	37	134	107	100	99	101	102
Dues & Subscriptions	371	440	525	532	543	553	565
Travel	85	85	89	92	94	96	98
Training	41	32	45	40	41	42	42
Meals	44	42	47	45	50	51	52
Supplies	29	16	24	25	26	26	27
Vehicle Expenses	33	44	33	34	34	35	36
Other	43	44	51	52	53	55	56
Total O&M Expense	8,781	8,527	8,634	8,773	8,973	9,264	9,490

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PPL companies

2017-2021 O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	8,847	9,075	9,243	9,440	9,647
Drivers:					
Labor Savings from Reorg	(250)	(258)	(265)	(273)	(281)
Other	37	(44)	(5)	97	124
Current Plan	8,634	8,773	8,973	9,264	9,490

LG&E KU
PPL companies

2015-2021 Margin Expenses / Cost of Sales ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Margin Expenses							
Mechanism Recoverable:							
Total	-	-	-	-	-	-	-
All other Cost of Sales:							
Industrial Coal Sales	734	975	942	942	943	943	944
EKPC NITS	2,884	2,688	2,549	2,559	2,531	2,511	2,512
OSS RTO	797	90	192	236	360	372	408
OSS 3rd Party XM	30	4	-	-	-	-	-
NL RTO	(4)	1	13	17	11	10	8
NL 3rd Party XM	316	204	42	26	17	15	9
Total (excluding interco)	4,757	3,962	3,738	3,780	3,862	3,851	3,881
NL Intercompany XM	753	705	699	702	730	781	823
OSS Intercompany XM	1,283	588	1,045	1,183	1,734	1,847	1,885
Total Margin/Cost of Sales	6,793	5,255	5,482	5,665	6,326	6,479	6,589

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LG&E KU PPL companies

2017-2021 Margin/Cost of Sales Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Mechanism recoverable					
Plan Expectation	-	-	-	-	-
Drivers					
Current Plan	-	-	-	-	-
Other Non-Mechanism					
Plan Expectation	5,987	6,007	6,461	6,560	6,533
Drivers:					
EKPC	36	28	-	(20)	(70)
OSS - RTO	(693)	(607)	(567)	(608)	(536)
NL - RTO	1	10	5	6	4
NL - 3rd Party XM	37	21	13	11	5
OSS - Interco XM	(59)	77	303	419	532
NL - Interco XM	104	60	42	42	69
Industrial Coal Sales	69	69	69	69	52
Current Plan	5,482	5,665	6,326	6,479	6,589

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LG&E KU PPL companies

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
VP Energy Supply	2	2	2	2	2	2	2
Power Supply	23	26	26	25	25	25	25
Director Financial P&A	2	2	2	2	2	2	2
Sales Analysis	5	7	7	7	7	7	7
Generation Planning	7	9	9	9	9	9	9
Economic Analysis	6	0	0	0	0	0	0
Fuels Management	6	5	5	5	5	5	5
Fuels & By Products	12	12	12	12	12	12	12
TOTAL	63	63	63	62	62	62	62
From 2016 Business Plan		63	64	64	63	63	
Change from 2016 Business Plan		-	(1)	(2)	(1)	(1)	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational						
2.) Compliance – NERC, FERC, CIP, etc.						
3.) EPA/Environmental						
4.) Administrative/Corporate			(1)			
TOTAL	-	-	**(1)**	-	-	-

	2016	2017	2018	2019	2020	2021
Contractor Offsets By Year: (New hire reducing contractor use)	**0**	**0**	**0**	**0**	**0**	**0**

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	0	0	0	0	0	0
Contractor Variance to 2016 Plan	0	0	0	0	0	

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PPL companies

Plan Risks

Appendix

PPL companies

Operational Performance

Key Performance Indicators

KPI	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
OSS Volume							
5x16	256	104	163	165	232	242	229
7x8	52	14	19	26	43	61	74
2x16	78	32	61	100	157	154	177
Effective Sales Price							
5x16	$48.15	$34.91	$33.31	$32.86	$33.84	$34.79	$36.39
7x8	$58.36	$40.68	$27.81	$30.63	$31.11	$33.66	$34.77
2x16	$43.43	$43.88	$32.65	$32.81	$33.68	$35.84	$36.92
Cost of Supply							
5x16	$31.43	$28.45	$25.56	$25.00	$24.95	$25.21	$26.29
7x8	$32.10	$25.81	$27.73	$27.14	$27.32	$27.45	$28.40
2x16	$29.99	$27.80	$25.39	$24.62	$24.56	$24.93	$25.89

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	**8,781**
Labor - Retirements	(168)
Labor - Backfill and Open Position Savings	(240)
Non-labor Outside Services	97
Other	57
2016 FC	**8,527**
Labor Retirements	(82)
Labor - Backfill and Open Position Savings	(71)
Labor - Merit Increases	177
Other	83
2017 Plan	**8,634**
Labor - Retirements	(136)
Labor - Early Hires for Fuels	48
Labor - Merit Increases	178
Other	49
2018 Plan	**8,773**
Labor - Reduction Early Hires	(48)
Labor - Merit Increases	182
Other	66
2019 Plan	**8,973**
Labor - Merit Increases	186
Other	105
2020 Plan	**9,264**
Labor - Merit Increases	192
Other	34
2021 Plan	**9,490**

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2015-2021 Walk Forward for GMEXP / Cost of Sales ($000)

2015 Actual	**6,793**
EKPC NITS	(196)
Industrial Coal Sales	241
OSS RTO	(707)
OSS Intercompany XM	(694)
Other	(182)
2016 FC	**5,255**
EKPC NITS	(139)
OSS RTO	103
OSS Intercompany XM	457
NL 3rd Party XM	(162)
Other	(32)
2017 Plan	**5,482**
OSS RTO	44
OSS Intercompany XM	138
Other	1
2018 Plan	**5,665**
OSS RTO	124
OSS Intercompany XM	551
Other	(14)
2019 Plan	**6,326**
NL Intercompany XM	51
OSS Intercompany XM	113
Other	(11)
2020 Plan	**6,479**
NL Intercompany XM	42
OSS Intercompany XM	38
Other	30
2021 Plan	**6,589**

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of August 2016)	61	0
Sales Analyst	1	
Generation Planner	1	
2016 Headcount FC - Year End	63	0
2017 Headcount Plan	63	0
Power Supply Retirement (no backfill)	(1)	
2018 Headcount Plan	62	0
2019 Headcount Plan	62	0
2020 Headcount Plan	62	0
2021 Headcount Plan	62	0

Describe type of work not necessarily positions – should explain need for additional headcount year over year (CIP; customer Service; compliance; etc.)

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LG&E KU PPL companies

PPL companies

Safety & Technical Training

2017 Business Plan

September 2016

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Plan Highlights

- Construction of Generation Training Facility at Trimble County Station, $1M CAPEX
- Expansion of EDO and GDO Training Facilities, $0.5M CAPEX

Major Assumptions

- Continue to improve upon safety targets
- Continue implementation of Guide to Safety Excellence
- Generation Training Facility will be in service by 4th Qtr 2017
- Headcount remains flat (31 Employees, 2 Contractors)
- EDO/GDO Training center renovations, simulators & Training yard expansion

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	3,040	3,237	3,449	3,509	3,594	3,697	3,773
Outside Services	285	220	83	123	99	88	90
Transportation	172	172	192	202	201	205	209
Job Aides	-	319	45	308	85	-	-
Education and Training	77	253	372	346	292	256	264
Safety Supplies/Materials	299	443	394	402	412	440	451
Safety Summit	177	155	186	192	196	200	204
Other	124	274	398	416	420	409	415
Total O&M Expense	**4,174**	**5,073**	**5,119**	**5,499**	**5,298**	**5,295**	**5,405**

PPL companies

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	5,211	5,591	5,390	5,391	5,503
Drivers:					
Other	(92)	(92)	(92)	(96)	(98)
Current Plan	5,119	5,499	5,298	5,295	5,405

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PPL companies

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Sheridan-Dir S&TT	**2**	**2**	**2**	**2**	**2**	**2**	**2**
Baker-Tech Training	**5**	**6**	**6**	**6**	**6**	**6**	**6**
Chambers-ETT&PS	**6**	**6**	**6**	**6**	**6**	**6**	**6**
Lindsey-ED&Trans	**6**	**7**	**7**	**7**	**7**	**7**	**7**
Murphy-Gas Safety	**4**	**6**	**5**	**5**	**5**	**5**	**5**
Chin - Gen Safety	4	4	4	4	4	4	4
Glove Lab	1	1	1	1	1	1	1
TOTAL	**28**	**32**	**31**	**31**	**31**	**31**	**31**
From 2016 Business Plan		32	31	31	31	31	
Variance to 2016 Business Plan		0	0	0	0	0	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	4	-1	0	0	0	0
2.) Compliance – NERC, FERC, CIP, etc.						
3.) EPA/Environmental						
4.) Administrative/Corporate						
TOTAL	**4**	**-1**	**0**	**0**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)						

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	2	2	2	2	2	2
Contractor Variance to 2016 Plan	0	0	0	0	0	

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LG&E KU PPL companies

Plan Risks

- Stricter Federal regulations pertaining to Operator qualifications for Gas Pipeline
- Aging equipment in Dielectric Testing Lab
- Ongoing Federal OSHA regulations

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Appendix

Operational Performance - Employees

8 3 2016 PROPOSAL (v10)

LG&E and KU Employees Corporate Summary Comparison
Proposed Targets for 2017 thru 2021

2017	CUST. SERVICE	GAS	ELECTRIC	SAFETY TECH. TRAINING	POWER PROD	GEN SERV/ PROJ ENG/ TRANSM	ENERGY SUPPLY	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2017 OSHA Incidence Rate	0.71	1.98	1.98	0	1.98	0.62	0	1.52	0.22	2.5	1.36
2017 Lost Work Day Case Rate	0.18	0.42	0.28	0	0.32	0.31	0	0.28	0.20	0	0.26
2017 DART Target	0.36	0.83	0.83	0	0.83	0.62	0	0.69	0.40	0	0.64
2018	CUST. SERVICE	GAS	ELECTRIC	SAFETY TECH. TRAINING	POWER PROD	GEN SERV/ PROJ ENG/ TRANSM	ENERGY SUPPLY	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2018 OSHA Incidence Rate	0.71	1.95	1.95	0	1.95	0.62	0	1.50	0.22	2.5	1.33
2018 Lost Work Day Case Rate	0.18	0.42	0.28	0	0.32	0.31	0	0.28	0.20	0	0.26
2018 DART Target	0.36	0.83	0.83	0	0.83	0.62	0	0.69	0.40	0	0.64
2019	CUST. SERVICE	GAS	ELECTRIC	SAFETY TECH. TRAINING	POWER PROD	GEN SERV/ PROJ ENG/ TRANSM	ENERGY SUPPLY	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2019 OSHA Incidence Rate	0.71	1.91	1.91	0	1.91	0.62	0	1.47	0.22	2.5	1.31
2019 Lost Work Day Case Rate	0.18	0.42	0.28	0	0.32	0.31	0	0.28	0.20	0	0.26
2019 DART Target	0.36	0.81	0.81	0	0.81	0.62	0	0.68	0.40	0	0.63
2020	CUST. SERVICE	GAS	ELECTRIC	SAFETY TECH. TRAINING	POWER PROD	GEN SERV/ PROJ ENG/ TRANSM	ENERGY SUPPLY	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2020 OSHA Incidence Rate	0.71	1.88	1.88	0	1.88	0.62	0	1.45	0.22	2.5	1.28
2020 Lost Work Day Case Rate	0.18	0.42	0.28	0	0.32	0.31	0	0.28	0.20	0	0.25
2020 DART Target	0.36	0.80	0.80	0	0.80	0.62	0	0.67	0.40	0	0.62
2021	CUST. SERVICE	GAS	ELECTRIC	SAFETY TECH. TRAINING	POWER PROD	GEN SERV/ PROJ ENG/ TRANSM	ENERGY SUPPLY	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2021 OSHA Incidence Rate	0.71	1.84	1.84	0	1.84	0.62	0	1.42	0.22	2.5	1.26
2021 Lost Work Day Case Rate	0.18	0.42	0.28	0	0.32	0.31	0	0.28	0.20	0	0.25
2021 DART Target	0.36	0.79	0.79	0	0.79	0.62	0	0.66	0.40	0	0.61

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Operational Performance - Contractors

8 3 2016 PROPOSAL (v10)

LG&E and KU Contractor Corporate Summary Comparison
Proposed Targets for 2017 thru 2021

2017	CUST. SERVICE	GAS	ELECTRIC	POWER PROD	PROJ ENG	TRANSMISSION	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2017 OSHA Incidence Rate	1.11	1.98	1.98	1.98	1.00	1.98	1.52	N/A	N/A	1.52
2017 Lost Work Day Case Rate	0.45	0.84	0.34	0.34	0.20	0.34	0.28	N/A	N/A	0.28
2018	CUST. SERVICE	GAS	ELECTRIC	POWER PROD	PROJ ENG	TRANSMISSION	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2018 OSHA Incidence Rate	1.11	1.95	1.95	1.95	1.00	1.95	1.50	N/A	N/A	1.50
2018 Lost Work Day Case Rate	0.45	0.84	0.34	0.34	0.20	0.34	0.28	N/A	N/A	0.28
2019	CUST. SERVICE	GAS	ELECTRIC	POWER PROD	PROJ ENG	TRANSMISSION	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2019 OSHA Incidence Rate	0.89	1.91	1.91	1.91	1.00	1.91	1.47	N/A	N/A	1.47
2019 Lost Work Day Case Rate	0.45	0.84	0.34	0.34	0.20	0.34	0.28	N/A	N/A	0.28
2020	CUST. SERVICE	GAS	ELECTRIC	POWER PROD	PROJ ENG	TRANSMISSION	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2020 OSHA Incidence Rate	0.89	1.88	1.88	1.88	1.00	1.88	1.45	N/A	N/A	1.45
2020 Lost Work Day Case Rate	0.45	0.84	0.34	0.34	0.20	0.34	0.28	N/A	N/A	0.28
2021	CUST. SERVICE	GAS	ELECTRIC	POWER PROD	PROJ ENG	TRANSMISSION	COO YTD	ADMIN	SUPPLY CHAIN	CORPORATE TOTALS
2020 OSHA Incidence Rate	0.71	1.84	1.84	1.84	1.00	1.84	1.42	N/A	N/A	1.42
2020 Lost Work Day Case Rate	0.45	0.84	0.34	0.34	0.20	0.34	0.28	N/A	N/A	0.28

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2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	4,174
Labor	197
Outside Svcs (Job Aides)	319
All Other	383
2016 FC	5,073
Labor	212
Outside Svcs (Job Aides)	(274)
All Other	108
2017 Plan	5,119
Labor	60
Outside Svcs (Job Aides)	259
All Other	61
2018 Plan	5,499
Labor	83
Outside Svcs (Job Aides)	(244)
All Other	(40)
2019 Plan	5,298
Labor	105
Outside Svcs (Job Aides)	(100)
All Other	(8)
2020 Plan	5,295
Labor	76
Outside Svcs (Job Aides)	2
All Other	32
2021 Plan	5,405

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2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of July 2016)	32	2
2016 Headcount FC - Year End	32	2
2017 Headcount Plan	32	2
Planned Retirement (January, 2017)	-1	
2018 Headcount Plan	31	2
2019 Headcount Plan	31	2
2020 Headcount Plan	31	2
2021 Headcount Plan	31	2

PPL companies

General Counsel

2017 Business Plan

September 2016

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Plan Highlights

- The 2017 General Counsel budget is under expectation by $0.4 million due to savings captured in Outside Counsel.
- Outside Counsel is 25% of the overall General Counsel budget. Current projections in the plan are consistent with historical spend. To meet expectation, previously included estimates for potential incremental outside counsel of $700k was eliminated from the 2017 budget.
- Headcount will increase by 3 from the 2016 forecast and will then remain flat through the remainder of the plan.

Major Assumptions

- Compliance
  - * *No significant changes in roles played by Compliance Department.*
  - * *Among the drivers for a change in required role could be changes in expectations in role from PPL perspective, new interpretation of current regulation, significant new or revised regulatory requirements, or increased demand for support from the business teams to reduce regulatory risks.*

LG&E KU PPL companies

Major Assumptions

- Communications
  * *This budget assumes we can maintain a positive trend in relation to our customer service ratings.*
  * *Similarly, this budget assumes we can continue to close customer satisfaction gap between LG&E and KU through targeted communications, advertising and increased sponsorship activation unless there are unforeseen circumstances.*

Major Assumptions

- Corporate Responsibility and Community Affairs
  - * *Negative community response, if any, in aftermath of rate case filing does not necessitate extraordinary community investment response.*
  - * *Criticism and scrutiny from environmental groups does not escalate dramatically.*
  - * *Relationships with Louisville Metro Council members do not deteriorate significantly.*
  - * *No significant deterioration in customer satisfaction ratings from low income customers.*
  - * *Our corporate-wide sustainability program responsibilities do not increase.*

Major Assumptions

- Environmental
  - * *EPA does not add or change MATS compliance requirements.*
  - * *The ash pond closure requirements are not materially changed from our 2016 ECR Plan.*
  - * *Kentucky Division of Water (DOW) agrees with our KPDES/ELG permitting and implementation schedule.*
  - * *Compliance with Kentucky's new Startup, Shutdown and Malfunction requirements are attainable.*
  - * *No new significant NOx reduction requirements either under CSAPR or a Section 126 petition.*
  - * *No major delay in obtaining permits needed to construct landfills.*

Major Assumptions

- Federal Regulation & Policy
  - * *Generally routine pace of rulemaking or policy initiatives from FERC. It is assumed that there will be a slightly lower level of new, major policy initiatives in 2017, since there will be a new commission composition following the presidential election.*
  - * *Continued moderate engagement by the Company in EEI or other industry group activities.*
  - * *No targeted initiative by Company to influence a particular policy matter.*
  - * *No other major developments at FERC or other forums (including Clean Power Plan) that will dictate fundamentally different resource needs for FR&P.*

Major Assumptions

- Legal
  - * *Hourly rates of outside providers will not materially increase.*
  - * *No significant unexpected developments in pending regulatory or litigation matters.*
  - * *No unanticipated material regulatory or litigation claims arise.*
  - * *One anticipated litigation matter will be avoided or delayed.*

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	9,483	9,471	10,135	10,454	10,741	11,119	11,390
Outside Counsel	6,270	7,962	7,990	8,542	8,808	8,860	8,742
Environmental Fees	3,470	3,513	3,783	3,967	4,127	4,278	4,439
Outside Services	1,975	2,579	2,954	2,775	2,789	2,868	2,836
Advertising	1,860	2,532	2,657	2,686	2,790	2,776	2,797
EEI Dues	592	692	715	732	751	770	789
Environmental Company Dues	632	561	714	728	743	758	773
Other Non Labor	2,326	2,703	2,337	2,216	2,259	2,278	2,289
Total O&M Expense	**26,609**	**30,012**	**31,284**	**32,100**	**33,006**	**33,705**	**34,054**

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O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	31,664	32,490	33,367	34,057	33,391
Drivers:					
Burdened Labor	183	139	242	403	421
Legal & EEI Dues	182	137	86	28	52
Air Emission Fees	83	67	(73)	(222)	(106)
Outside Counsel	(680)	(301)	(213)	(341)	(550)
Other	(147)	(432)	(403)	(221)	848
Current Plan	31,284	32,100	33,006	33,705	34,054

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Office of GC	2	2	2	2	2	2	2
Legal & Federal Reg	24	23	25	25	25	25	25
Enviromental	21	21	22	22	22	22	22
Communciations	19	19	19	19	19	19	19
Compliance	8	8	8	8	8	8	8
Corporate Resp.	6	6	6	6	6	6	6
External Affairs	4	4	4	4	4	4	4
Interns	2	3	3	3	3	3	3
TOTAL	**86**	**86**	**89**	**89**	**89**	**89**	**89**
From 2016 Business Plan		87	87	87	87	87	
Change from 2016 Business Plan		(1)	2	2	2	2	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Environmental Intern (open)	1	0	0	0	0	0
2.) VP Fed Reg & Policy (retired)	(1)	0	0	0	0	0
3.) FERC Attorney (replace VP FRP)	0	1	0	0	0	0
4.) Legal Secretary (backfill)	0	1	0	0	0	0
5.) Environmental (new)*	0	1	0	0	0	0
TOTAL	**0**	**3**	**0**	**0**	**0**	**0**

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	1	1	1	1	1	1
Contractor Change from 2016 Plan	0	0	0	0	0	

**The cost for the additional Environmental position will be completely offset by a reduction to Outside Services.*

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LG&E KU PPL companies

Plan Risks

- Compliance

  * *Headcount needs could increase if support required by other groups increases. The most likely cause for this would be enhanced expectations due to changes in the PPL overall compliance program. However, demand for support could come from changes in regulatory requirements or increased demand for support from the business teams to reduce regulatory risks.*

Plan Risks

- Communications
  - * *Continued increases in customer bills could potentially result in lower customer satisfaction levels.*
  - * *Environmental opposition to the CCR rule could result in litigation and adverse media exposure.*
  - * *Changing workforce could result in lower community support and brand allegiance.*

Plan Risks

- Corporate Responsibility and Community Affairs
  - * *Adverse weather and/or natural disasters may necessitate new levels of assistance for agencies addressing the needs of our challenged customers.*
  - * *Unfavorable legal or regulatory result may require focused community relations strategy.*

Plan Risks

- Environmental

  * *Inability to beneficially use CCR materials in the closure of ash ponds.*
  * *MATs compliance requires additional controls or monitoring equipment.*
  * *Implementation of new wastewater discharge standards (ELG) require additional resources.*
  * *Inability to obtain construction or operating permits (e.g. landfill) in a timely manner.*
  * *CPP remains in effect without delaying the compliance dates.*
  * *Greater than predicted increases in Title V Emission Fees.*

    ** From 2011-2015, the average yearly increase was 11%.*

LG&E KU PPL companies

Plan Risks

- Federal Regulation & Policy
  - * *New FERC chairman and/or new commissioners set aggressive agenda for major policy initiatives in which the Company must engage.*
  - * *Particular regulations and policies that affect issues critical to the company are initiated (e.g., RTO membership, certain manifestations of federal/state jurisdictional questions).*

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Plan Risks

- Legal
  - * *Reduced Outside Counsel budget by potential incremental needs of $700k to meet expectation, therefore existing budget does not allocate funds for material contingencies, and is particularly tight for 2017 so that surrender of funds during the year is highly unlikely absent material favorable developments resulting in savings.*
  - * *Litigation against the Company under CCR Rule, Clean Power Plan and other environmental rules is likely to develop and require significant resources not covered in present budget.*
  - * *The Company could become involved in a significant unanticipated legal dispute.*
  - * *Unanticipated shift in timing of key steps in legal matters could shift expenses from one year to next.*

LG&E KU PPL companies

Appendix

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	26,609
Intercompany Charges	1,419
Outside Counsel	1,692
Other	292
2016 FC	30,012
Outside Services	375
Labor	664
Environmental Fees	270
Other	(37)
2017 Plan	31,284
Outside Counsel	552
Environmental Fees	184
Other	80
2018 Plan	32,100
Outside Counsel	265
Environmental Fees	160
Other	481
2019 Plan	33,006
Environmental Fees	151
Labor	377
Other	171
2020 Plan	33,705
Environmental Fees	161
Other	188
2021 Plan	34,054

PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of July 2016)	87	1
Overlap of Environmental Manager in July	(1)	
2016 Headcount FC - Year End	86	1
FERC Attorney - Legal	1	
Legal Secretary	1	
Environmental Air Scientist	1	
2017 Headcount Plan	89	1
2018 Headcount Plan	89	1
2019 Headcount Plan	89	1
2020 Headcount Plan	89	1
2021 Headcount Plan	89	1

PPL companies

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PPL companies

Human Resources

2017 Business Plan

September 2016

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Plan Highlights

- Total OPEX reduction of $1.2 million over 2017-2020 relative to the 2016 HR Business Plan
- Headcount remains flat for the plan
- The plan provides sufficient resources for HR to execute its mission of attracting, developing and retaining employees to meet business needs.

Major Assumptions

- We will continue to see high levels of retirements – over 130 in 2016 with as many projected for each year of the plan.
- We will continue to see a significant volume of open positions in each year of the plan (over 300 filled in current year).
- We will continue to see significant internal movement to roles with increasing responsibility (over 285 promotions in 2016).
- We will continue to see changes in the health insurance market that will impact company costs.
- Upcoming union negotiations will be routine.

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	5,590	5,654	5,583	5,785	5,955	6,167	6,320
Wellness	123	136	227	227	227	227	227
Outside Services-Other	185	205	446	396	358	333	232
Outside Services-Wellness	109	128	143	145	147	149	151
Travel & Meals	165	217	275	276	258	289	293
Recruiting	54	124	120	122	124	126	128
Training	107	105	112	120	122	106	116
Other Non-Labor	246	296	405	395	385	416	389
Total O&M Expense	**6,579**	**6,866**	**7,311**	**7,466**	**7,576**	**7,814**	**7,856**

LG&E KU PPL companies

O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	7,311	7,505	7,602	7,724	7,868
Drivers:					
Labor	(230)	(195)	(147)	(78)	(78)
Employee Opinion Survey	120	-	-	122	-
Diversity Training	15	40	-	-	25
Outside Services	53	95	95	(53)	(60)
Other	42	21	26	99	101
Current Plan	7,311	7,466	7,576	7,814	7,856

LG&E KU
PPL companies

2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
VP HR & Directors	21	21	21	21	21	21	21
Diversity	1	1	1	1	1	1	1
Benefits	6	6	6	6	6	6	6
Compensation	2	2	2	2	2	2	2
Industrial Relations	3	3	3	3	3	3	3
Health & Wellness	3	3	3	3	3	3	3
Talent Mgmt & HRIS	9	9	9	9	9	9	9
Staffing Services	9	9	9	9	9	9	9
Interns	1	0	2	2	2	2	2
TOTAL	**55**	**54**	**56**	**56**	**56**	**56**	**56**
From 2016 Business Plan		56	56	56	56	56	
Change from 2016 Business Plan		-2	0	0	0	0	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	-	-	-	-	-	-
2.) Compliance – NERC, FERC, CIP, etc.	-	-	-	-	-	-
3.) EPA/Environmental	-	-	-	-	-	-
4.) Administrative/Corporate	-	2	-	-	-	-
TOTAL	**0**	**2**	**0**	**0**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)	**0**	**0**	**0**	**0**	**0**	**0**
	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	0	0	0	0	0	0
Contractor Change from 2016 Plan	0	0	0	0	0	0

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Excludes Interns

LG&E KU PPL companies

Plan Risks

- Company turnover increases beyond anticipated levels.
- Union negotiations do not go as anticipated.
- Changes in law and regulation impact our business.
- Medical plan self insurance could impact financial results.

Appendix

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	6,579
Labor & Burdens	64
Outside Services	39
Recruiting	70
Other Non Labor	113
2016 FC	6,866
Labor & Burdens	(71)
Outside Services	256
Wellness	170
Other Non Labor	91
2017 Plan	7,311
Labor & Burdens	202
Outside Services	(48)
Other Non Labor	2
2018 Plan	7,466
Labor & Burdens	170
Outside Services	(36)
Other Non Labor	(24)
2019 Plan	7,576
Labor & Burdens	212
Outside Services	(22)
Other Non Labor	48
2020 Plan	7,814
Labor & Burdens	153
Outside Services	(100)
Other Non Labor	(11)
2021 Plan	7,856

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2016-2021
Headcount Progression Year To Year

	Company Employees
2016 Headcount (As of August 2016)	51
Current HR associate openings	2
Current HR manager opening	1
2016 Headcount FC - Year End	54
HR Intern Positions filled	2
2017 Headcount Plan	56
2018 Headcount Plan	56
2019 Headcount Plan	56
2020 Headcount Plan	56
2021 Headcount Plan	56

PPL companies

Information Technology

2017 Business Plan

September 2016

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Plan Highlights

- The 2017 Information Technology O&M budget submitted for the 2017 Business Plan is $59.2 million.
- IT headcount remains flat throughout the plan years.
- Outside services for the current business plan increases in 2018 due to the addition of 4 resident contractors to support Telecom Infrastructure and Dev and Support - Work Management groups for the DA project.
- The plan assumes a consolidated IT Infrastructure and Operations department across Kentucky and Pennsylvania.
- The plan includes a GIS assessment for $500k in 2017 and an Oracle assessment for $700k in 2017.

PPL companies

Plan Highlights

- The 2017 Information Technology Capital budget is $49 million, which is $800k higher than the 2016 Business Plan.
  - *The increase is primarily due to the addition of the Mobile Dispatch Replacement project and shifting a portion of the Design Tool Upgrade (WIM) project from 2016 into 2017. This increase was largely offset by reductions in Infrastructure capital projects.*
- Business demand for technology continues to drive an increase in IT Capital and O&M.

Major Assumptions

- Major Initiatives
  - *Roughly 54% of the 5 year capital plan (approximately $106M) represents 17 major initiatives (including $21M for SAP, $15M for GIS and $15M for Tech Refresh).*
  - *All costs (capital and O&M) for AMS is included in the Customer Services business plan.*

- Safety & Regulatory
  - *Increased regulatory scrutiny at FERC, NERC and SERC as it relates to Critical Infrastructure Protection (CIP) and cybersecurity will drive the need for increased spending for both labor and information technology solutions to meet compliance requirements.*

Major Assumptions

- Business Reliance on Technology
  - *Business reliance on information technology services to conduct day to day operations continues to expand. Due to increased regulatory requirements, more business processes are moving towards automation.*
  - *This trend means the reliability and availability of information technology services is critically important to the business. There is little tolerance for almost any kind of system outage. This leads to an increased focus on planned and automated testing activities for all major system changes.*
  - *Increased reliance on technology is leading to increased storage, maintenance and support costs which are reflected in the plan.*

Major Assumptions

- Customer Experience
  - *As our primary interface with our customers, maintaining the CCS system is critical to meet customer and business expectations. This includes release upgrades to the SAP applications and hardware refresh and expansion.*
  - *Efforts to support the customer experience initiative continue with capital projects such as call center technology improvements.*
  - *Expansion of green energy technologies will require enhancements to the CCS system.*

Major Assumptions

- Cybersecurity Threats
  - *IT Security threats and data protection issues continue to increase. These threats are becoming even more sophisticated and difficult to overcome. Continued investment in protective and preventive measures to reduce these threats are required and included in the plan.*

- Advances in New Technologies
  - *Continuing to leverage mobile technologies will be a major differentiator for productivity and customer satisfaction.*
  - *Plans include working closely with the business to determine which of these technologies can deliver the greatest benefit.*

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Labor	26,507	27,071	27,867	29,351	30,067	31,010	31,675
HW/SW Maintenance*	18,089	18,769	20,329	21,937	23,244	23,729	24,546
O/S Services	5,302	5,649	5,170	5,432	5,442	5,599	5,731
Telecom	2,782	2,940	3,137	3,414	3,549	3,743	3,897
Training, Travel, & Meals	1,375	1,381	1,478	1,595	1,576	1,608	1,640
Vehicles/Equipment	257	269	289	294	300	306	312
Other Non-Labor	746	863	941	1,052	1,082	1,104	1,128
Total O&M Expense	**55,058**	**56,942**	**59,211**	**63,076**	**65,260**	**67,098**	**68,929**

**Includes Hosted Subcriptions*

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O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	60,974	62,949	64,614	66,577	67,635
Drivers - Increase/(Decrease):					
IT HW/SW Maintenance*	(271)	(363)	(356)	(371)	205
Outside Services	(830)	232	42	(1)	75
Telecom	(147)	97	198	359	479
All Other**	(515)	160	762	534	535
Current Plan	59,211	63,076	65,260	67,098	68,929

**Includes Hosted Subcriptions*

*** Labor savings was used to reduce stretch gap in 2016BP.*

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2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Chief Information Officer	2	2	2	2	2	2	2
IT Enterprise Business Services	2	2	2	2	2	2	2
IT Business Services	46	39	39	39	39	39	39
IT Dev & Support - Corp Services	37	39	39	39	39	39	39
IT Dev & Support - Customer Servi	26	25	25	25	25	25	25
IT Dev & Support - Operations	16	15	15	15	15	15	15
IT Enterprise Infrastructure	150	159	157	157	157	157	157
IT Security & Compliance	15	20	21	21	21	21	21
Interns	4	8	7	7	7	7	7
TOTAL	**298**	**309**	**307**	**307**	**307**	**307**	**307**
From 2016 Business Plan		319	319	328	337	337	
Change From 2016 Business Plan		(10)	(12)	(21)	(30)	(30)	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) Maintenance /Operational	-	-	-	-	-	-
2.) Compliance – NERC, FERC, CIP, etc.	5	-	-	-	-	-
3.) EPA/Environmental	-	-	-	-	-	-
4.) Administrative/Corporate	5	(2)	-	-	-	-
TOTAL	**10**	**(2)**	**0**	**0**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)	**0**	**0**	**0**	**0**	**0**	**0**

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	32	25.5	29.5	29.5	29.5	29.5
Contractor Change from 2016 Plan	(8)	(11.5)	(10.5)	(10.5)	(11.5)	

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Plan Risks

- The assessment of resource requirements will continue and may lead to the need for additional resources as evaluation continues and we gain more understanding of CIP V5.

- Acquiring skilled IT Security and Infrastructure resources will continue to be a challenge for us and the rest of the industry.

- Approximately 53 FTEs are at risk to capital labor for 2017 and 47 for 2018 to 2020; $7.8m for 2017 and $6.8m from 2018 to the end of the plan. Any subsequent changes to the capital plan may adversely impact O&M.

- Project assessments and software maintenance contract renewals for significant systems costs may be materially higher than planned (e.g., Oracle and GIS).

Plan Risks

- Changes in vendor pricing models to subscriptions for hardware/software maintenance agreements could lead to increased O&M.
- Funding for system rationalization is not included in the plan. While planned work may be reprioritized, some work will be incremental.
- Changes in industry regulatory requirements may lead to an increase in capital and O&M costs.
- 2017 BP spend does not include unplanned business initiatives that may have an impact on IT O&M.
- Loss of knowledge related to increased level of employee retirements.

Appendix

PPL companies

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	**55,058**
Labor	564
HW/SW Maintenance*	680
O/S Services	348
Other Non-Labor	293
2016 FC	**56,942**
Labor	796
HW/SW Maintenance*	1,560
O/S Services	(480)
Other Non-Labor	392
2017 Plan	**59,211**
Labor	1,484
HW/SW Maintenance*	1,609
O/S Services	263
Other Non-Labor	510
2018 Plan	**63,076**
Labor	717
HW/SW Maintenance*	1,307
O/S Services	9
Other Non-Labor	152
2019 Plan	**65,260**
Labor	943
HW/SW Maintenance*	485
O/S Services	157
Other Non-Labor	253
2020 Plan	**67,098**
Labor	665
HW/SW Maintenance*	817
O/S Services	132
Other Non-Labor	217
2021 Plan	**68,929**

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PPL companies

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of July 2016)	**292**	**33**
Sr. Secretary (Butler)	1	-
IT Project Leader (Sullivan)	1	-
IT Test Engineer (Deschamp)	1	-
IT Systems Engineer (1 Kachurick, 1 Bauerla, 2 Snyder)	4	-
UC Engineer (Crawford)	1	-
Technical Support (Cannon)	1	-
IT Business Sys Analyst (Keemer)	1	-
Programmer/Analyst (1 Deschamp, 2 M. Smith)	3	-
Interns (Reffett, Shaver, M. Smith, Schrenger)	4	-
Project Management (Sullivan)	-	1
Telecom Tech (Reffett)	-	(1)
Developer (Brumfield)	-	(1)
2016 Headcount FC - Year End	**309**	**32**
Client Support (Martin)	(2)	-
QA/Testing (Deschamp)	1	-
Intern (Peek)	(1)	-
Project Management (Sullivan)	-	(1)
Dev & Support (Deschamp)	-	(1.5)
Applications Development (Lepianka)	-	(1)
Development (M. Smith)	-	(1)
TSC Support (Cannon)	-	(2)
2017 Headcount Plan	**307**	**25.5**
Telecom Tech (Reffett)	-	2
Developer (Schrenger)	-	2
2018 Headcount Plan	**307**	**29.5**
2019 Headcount Plan	**307**	**29.5**
2020 Headcount Plan	**307**	**29.5**
2021 Headcount Plan	**307**	**29.5**

2017-2021 HW/SW Maintenance* ($000)

Vendor Name	Product	2017 Amortization	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization
ORACLE AMERICA INC	ULA (DB & Middleware)	1,843	1,901	1,977	2,057	2,139
CONTINGENCY	Contingency	1,398	2,008	1,897	1,170	1,539
NEW CAPITAL	New Capital	420	976	1,660	2,089	2,255
SAP INDUSTRIES	All SAP Products	1,326	1,326	1,326	1,326	1,379
MICROSOFT CORP	EA	1,222	1,278	1,329	1,382	1,438
ORACLE AMERICA INC	Oracle Applications	978	1,017	1,058	1,100	1,144
WORLD WIDE TECHNOLOGY INC	Smartnet	765	683	832	835	782
GE ENERGY MANAGEMENT SERVICES LLC	Smallworld	436	458	481	505	530
IBM CORPORATION	Maximo	430	447	465	483	503
ABB ENTERPRISE SOFTWARE INC	Service Suite	381	397	412	429	446
IBM CORPORATION	ISS Appliances	349	363	377	392	408
NORTH AMERICAN ELEC RELIABILITY CORP	CRISP	341	355	369	384	399
POWERPLAN INC	PowerPlan	353	339	353	367	382
EMC CORP	TLA	179	325	385	400	416
TAX	Tax	277	318	365	457	234
ORACLE AMERICA INC	Peoplesoft	295	307	319	332	345
CGI TECHNOLOGIES AND SOLUTIONS INC	ARM maintenance	326	289	295	307	319
GARTNER RESEARCH	Gartner Subscription	264	275	286	297	309
PROSYS INFORMATION SYSTEMS INC	VM Ware	274	267	267	275	277
RED HAT INC	RedHat	245	247	257	267	278
OSISOFT LLC	PI Client Applications and Server	217	225	234	244	253
ABB ENTERPRISE SOFTWARE INC	nMarket	210	218	227	236	245
ORACLE AMERICA INC	SPL/NMS	208	217	226	235	244
GE ENERGY MANAGEMENT SERVICES LLC	MapFrame	205	213	222	231	240
DNV GL	Cascade & LOAD	200	208	216	225	234

PPL companies

2017-2021 HW/SW Maintenance* ($000)

Vendor Name	Product	2017 Amortization	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization
CINCINNATI BELL TECHNOLOGY SOLUTIONS	Solutionary	21	249	259	270	281
CINCINNATI BELL TECHNOLOGY SOLUTIONS	Contact Center Routing	208	208	208	214	217
IBM CORPORATION	Big Data & Analytics Solution	171	171	187	239	249
IBM CORPORATION	QRadar Appliances	226	226	226	226	94
PROSYS INFORMATION SYSTEMS INC	Isilon	195	195	195	195	200
LOGRHYTHM INC	11x5 support & Other	130	200	206	213	219
OPEN TEXT INC	Content Lifecycle Mgmt & Email	173	180	187	195	202
CITRIX SYSTEMS INC	Citrix Products	170	177	184	191	199
MICROSOFT CORP	Microsoft Premier Support	151	157	163	170	177
AVNET INC	HPQC	139	145	151	157	163
SUNGARD ENERGY SYSTEMS INC	Aligne Fuels	138	144	150	156	162
ENVIRONMENTAL SYSTEMS CORP	Stackvision	137	142	147	153	159
NETSCOUT SYSTEMS INC	Appliances	133	133	133	139	140
TBD	Distribution Automation	121	126	131	136	141
WALKER AND ASSOCIATES INC	Envision and DNX	117	121	124	128	132
MICROSOFT CORP	ECI	118	120	120	124	129
LIGHTRIVER TECHNOLOGIES INC	DMX, DMX10	101	105	109	113	118
DYNAMIC RISK ASSESSMENT SYSTEMS INC	Gas Integrity Management	102	105	108	111	115
PROSYS INFORMATION SYSTEMS INC	Palo Alto	84	109	108	107	111
PITNEY BOWES SOFTWARE INC	GeoStan	101	101	101	105	105
Cherwell	SDE Replacement	130	86	91	95	99
EPIS INC	AURORAxmp	92	96	99	103	107
PROSYS INFORMATION SYSTEMS INC	Data Domain	124	120	79	81	81
SAP INDUSTRIES	CDP Development	93	93	93	93	93
PROSYS INFORMATION SYSTEMS INC	XtremIO	90	90	90	96	95
ALL OTHER		4,234	4,020	4,109	4,240	4,392
Grand Total		**20,639**	**22,276**	**23,593**	**24,075**	**24,917**

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CFO Group

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Plan Highlights

- CFO group is designed to meet the overall objectives of the Company in the most cost effective manner possible.
  - *Functions include accounting, financial reporting, regulatory reporting, tax, payroll, financing, cash management, investor relations, forecasting & budgeting, financial planning & analysis, insurance, pensions, rates, state regulatory affairs, audit services and supply chain.*
- CFO budget is below expectation each year.
- Headcount will decrease by one compared to the 2016 forecast and will remain flat throughout the plan.
  - *Labor represents 45% of the CFO 2017BP O&M expenses.*
- Insurance premiums have been moved from Corporate to CFO budget as that is the group responsible for managing these costs.
  - *Insurance represents 40% of the CFO 2017BP O&M expenses.*

PPL companies

Major Assumptions

- Projected insurance premium increases are based on renegotiated rates and increase for amount of property placed in service.
- Audit fees are based on negotiated rates with firms and expected incremental work (e.g., consent letters for financings)
- Bank Fees, excluding rating agency fees, are projected to increase at 1% annually based on recent experience.
- Supply chain will be responsible for joint IT procurement for KY and PA; joint related costs will be allocated based on total network users cost allocation methodology.

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Utility Expenses Only:							
Labor	19,825	19,851	20,525	21,041	21,551	22,259	22,804
Insurance*	724	1,583	16,732	18,223	19,221	19,940	20,693
Rate Case Amortization	1,588	1,112	1,661	1,654	2,172	2,160	2,220
Audit Fees	1,347	1,596	1,718	1,719	1,587	1,603	1,619
Bank Fees	1,463	911	1,575	1,626	1,676	1,741	1,804
Outside Services	244	439	358	270	416	360	356
Other	1,215	3,192	3,192	3,088	3,292	3,177	2,907
Total O&M Expense	**26,406**	**28,684**	**45,760**	**47,622**	**49,916**	**51,241**	**52,405**

*Moved Insurance from the Corporate budget to CFO for the 2017 BP

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O&M Annual Expense Reconciliation ($000)

	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Plan Expectation	48,162	50,183	53,111	55,420	58,264
Drivers:					
Insurance	(2,914)	(2,992)	(3,795)	(4,928)	(6,212)
Labor	618	549	618	813	817
Bank & Audit Fees	35	(24)	(144)	(150)	(111)
Other Non Labor	(140)	(94)	126	87	(353)
Current Plan	45,760	47,622	49,916	51,241	52,405

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2015-2021 Headcount Totals & Changes

Department	2015 Year End	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
CFO	2	2	2	2	2	2	2
Controller	69	70	70	70	70	70	70
Audit	13	14	14	14	14	14	14
Treasurer	57	57	56	56	56	56	56
Supply Chain	53	57	57	57	57	57	57
State Reg & Rates	15	16	16	16	16	16	16
Interns	12	12	12	12	12	12	12
TOTAL*	**221**	**228**	**227**	**227**	**227**	**227**	**227**
From 2016 Business Plan		224	224	224	224	224	
Change from 2016 Business Plan		4	3	3	3	3	

Year to Year Increases (Decreases)	2016	2017	2018	2019	2020	2021
1.) IT SC Sourcing Transfer	4	-	-	-	-	-
2.) Controller - Accounting Analyst	1	-	-	-	-	-
3.) Audit - IT Auditor	1	-	-	-	-	-
4.) Rates & Regulatory Analyst	1	-	-	-	-	-
5.) Treasurer - Budget Analyst	-	(1)	-	-	-	-
TOTAL	**7**	**(1)**	**-**	**-**	**-**	**-**

	2016 FC	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Resident Contractors By Year:	21	21	21	21	21	21
Contractor Change from 2016 Plan	8	8	8	8	8	

*Includes transfer of 3 employees from IT to Supply Chain.

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Plan Risks

- An increased focus on IT security and other technical areas may require increased use of external resources for related audits.
- Integration of primary system changes within planning window and their impact on existing processes (PowerPlan, Volts replacement, Oracle, etc.).
- Maintaining flat staffing levels allow for limited resources available for special projects.
- Higher level of employee retirements during plan period place greater emphasis on knowledge transfer and effective timing of staffing changes.
- The level of rate increases for insurance premiums are at historically low levels and creates a level of risk regarding future premiums.

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Appendix

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	26,406
Intercompany Charges	2,942
Bank Fees	(552)
Other	(112)
2016 FC	28,684
Insurance	15,156
Labor	782
Rate Case Amortization	549
Other	589
2017 Plan	45,760
Insurance	1,492
Labor	539
Other	(169)
2018 Plan	47,622
Insurance	998
Rate Case Amortization	518
Labor	543
Other	235
2019 Plan	49,916
Insurance	720
Labor	727
Other	(122)
2020 Plan	51,241
Insurance	753
Labor	317
Other	94
2021 Plan	52,405

PPL companies

2017–2021 O&M Expenses by Group ($000)

	2017	2018	2019	2020	2021
Audit Services	1,678	1,734	1,795	1,884	1,903
Controller	8,888	9,070	9,184	9,422	9,563
Other	2,303	2,351	2,406	2,446	2,174
State Reg and Rates	4,166	4,006	4,814	4,648	4,842
Supply Chain	4,359	4,411	4,501	4,643	4,754
Treasurer	24,366	26,050	27,215	28,199	29,169
Grand Total	**45,760**	**47,622**	**49,916**	**51,241**	**52,405**

2016-2021
Headcount Progression Year To Year

	Company Employees	Resident Contractors
2016 Headcount (As of July 2016)	222	21
IT Auditors	2	
Controller Intern	1	
Supply Chain Support Analysts	2	
Supply Chain Storeroom Specialist	1	
2016 Headcount FC - Year End	228	21
Retiring Budget Analyst	(1)	
2017 Headcount Plan	227	21
2018 Headcount Plan	227	21
2019 Headcount Plan	227	21
2020 Headcount Plan	227	21
2021 Headcount Plan	227	21

PPL companies

2015-2021 Other Balance Sheet Costs ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Stores Expense							
Labor	1,363	1,401	1,572	1,622	1,664	1,719	1,763
Non labor*	475	1,417	1,415	1,429	1,443	1,457	1,472
Total	1,838	2,818	2,986	3,051	3,107	3,176	3,235
Regulatory Asset							
Rate Case Expenses**	1,035	2,297	1,287	4,004	540	2,548	1,109
Total	1,035	2,297	1,287	4,004	540	2,548	1,109
Total Other Costs	2,873	5,115	4,273	7,055	3,647	5,724	4,344

*Stores Expense - the 2015 Actual Non Labor amount is lower by $375k due to a correction of a December 2014 charge (should have hit capital instead of stores in 2014).

**For 2015, regulatory asset amounts incurred by Legal are in the General Counsel actuals. For reporting purposes, the amounts were combined in the CFO presentation.

PPL companies

Corporate Cost Center

2017 Business Plan

September 2016

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Major Assumptions

- Benefits for 2017 based on 3,591 full-time, 80 co-ops/interns, and 20 part-time regular employees (as of 12/31/17)
  - *Full-time actual headcount at July 31, 2016 is 3,477.*
  - *Benefits for each year based on the respective year's headcount, ranging as high as 3,615 full-time in July, 2018.*
- Pension based on actuarial calculations based on the RP-2014 mortality table and MP-2015 projection scale, assumptions, and rate case settlement;
  - 15 year amortization period used, for LG&E and KU jurisdictional.
    - Double corridor used for Virginia, FERC and Capital Corp. charges from LKS.
    - Discount rate is assumed to be 4.42% for the Non-Union plan and 4.34% for the Union plan, which reflects the April 30, 2016 BondLink results plus 25 basis points for both plans for measurement date December 31, 2016 and beyond.
    - Service cost is assumed to remain constant (0.00% growth).

Major Assumptions

- The projection for medical will remain flat to the 2016 Budget and adjusted for incremental headcount. This matches the company portion of the 4/4/50% sharing relationship with employees.
  - *As a point of reference, actual medical/dental expenses from 2010-2015 averaged a 3.7% annual increase.*
- Amortization of regulatory assets will continue through plan periods based on KPSC orders.
- Incentive expenses based on:
  - *Financial, team, and customer service goals at 100%.*
  - *Individual effectiveness at 120%.*
    - *The past three years have averaged 119%.*
- IMEA/IMPA portion included in Corporate is the credit that covers the same burden types that hit Corporate. The balance of IMEA/IMPA is in Power Production.
- Insurance Expense (moved to CFO) and Facilities Expense (moved to Customer Services) are removed from Corporate beginning January 1, 2017.

2015-2021 Annual O&M Expenses ($000)

Item	2015 Actual	2016 Forecast	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
O&M Expenses Only:							
Pension	33,691	21,098	28,933	28,084	24,331	22,844	22,743
Post Retirement (FAS 106)	8,263	6,403	5,698	5,535	5,373	5,241	4,948
Medical/Dental	25,381	26,967	29,383	30,541	31,763	33,033	34,354
Payroll Taxes	19,680	21,014	20,984	21,286	21,924	22,582	23,259
401k Drop In	9,093	8,898	9,595	9,837	10,132	10,436	10,749
Other Benefits	6,043	10,847	10,510	12,364	12,973	13,624	14,322
Subtotal	**102,152**	**95,227**	**105,103**	**107,646**	**106,495**	**107,759**	**110,376**
Amortization of Regulatory Assets	15,466	14,821	15,056	13,270	13,270	7,903	389
A&G Transferred Credit	(9,936)	(9,258)	(10,095)	(10,476)	(10,758)	(11,001)	(11,219)
IMEA/IMPA Billings	(4,116)	(4,511)	(4,281)	(4,419)	(4,591)	(4,750)	(4,875)
Life Insurance	(1,900)	(1,711)	(1,835)	(1,874)	(1,913)	(1,954)	(1,996)
Property/Liability Insurance	14,898	14,314	-	-	-	-	-
Facilities	11,685	10,356	-	-	-	-	-
Other	(667)	4,216	(332)	2,526	2,964	(735)	445
Total O&M Expense	**127,582**	**123,454**	**103,616**	**106,673**	**105,467**	**97,222**	**93,120**

O&M Annual Expense Reconciliation ($000)

	Plan	Plan	Plan	Plan	Plan
Plan Expectation	96,158	98,334	99,661	96,567	91,278
Drivers:					
Pension	7,914	5,638	2,806	1,682	1,582
Post Retirement (FAS 106)	(843)	(928)	(951)	(928)	(1,221)
Medical/Dental	1,457	1,391	1,337	1,010	1,014
Payroll Taxes	(1,150)	(1,519)	(1,573)	(1,628)	(1,684)
401k Drop In	88	40	37	34	31
Other Benefits	702	2,043	2,101	2,160	2,222
Amort. of Reg Assets	473	-	-	-	-
A&G Transferred Cr	721	903	1,064	1,206	1,337
IMEA/IMPA Billings	(381)	(419)	(491)	(450)	(532)
Other	(1,523)	1,191	1,476	(2,432)	(907)
Current Plan	103,616	106,673	105,467	97,222	93,120

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Plan Risks

- The largest plan risk by far is pension expense.
- The second largest risk is medical expense, but it is partially mitigated by the 4/4/50 sharing relationship.

Appendix

2015-2021 Walk Forward for O&M Expenses ($000)

2015 Actual	127,582
Labor Burdens	(8,133)
Amort. of Reg Asset	(645)
A&G Transferred Credit	582
Other	3,418
2016 FC	122,804
Labor Burdens	11,084
Amort. of Reg Asset	235
A&G Transferred Credit	(741)
Property/Liability Insurance	(14,433)
Facilities	(11,427)
Other	(1,931)
2017 Plan	105,591
Labor Burdens	2,543
Amort. of Reg Asset	(1,786)
A&G Transferred Credit	(381)
Other	(169)
2018 Plan	105,798
Labor Burdens	(1,151)
A&G Transferred Credit	(282)
Other	(203)
2019 Plan	104,162
Labor Burdens	1,264
Amort. of Reg Asset	(5,367)
A&G Transferred Credit	(243)
Other	(1,289)
2020 Plan	98,527
Labor Burdens	2,617
Amort. of Reg Asset	(7,514)
A&G Transferred Credit	(218)
Other	(292)
2021 Plan	93,120

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2014-2021 – Amortization of Regulatory Assets Detail

	LG&E						KU					TOTAL
	Winter 2009 Ice Storm	2009 Wind Storm	Wachovia Swap	Summer Storm Aug.	CMRG	MISO	Winter 2009 Ice Storm	2009 Wind Storm	Virginia Mountain	CMRG	MISO	
Amortization Start	**08/2010**	**08/2010**	**01/2013**	**01/2013**	**08/2010**	**01/2013**	**08/2010**	**08/2010**	**11/2011**	**08/2010**	**01/2013**	
Amortization Complete	**07/2020**	**07/2020**	**04/2035**	**12/2017**	**07/2020**	**12/2015**	**07/2020**	**07/2020**	**12/2017**	**07/2020**	**12/2015**	
2013 Beginning Balance	33,244,113	17,851,419	-	-	739,830	-	43,404,542	1,664,933	4,631,947	776,837	-	102,313,621
Additions	-	-	8,678,746	8,052,125	-	-	-	-	-	-	-	16,730,871
Amortization	(4,383,839)	(2,354,033)	(388,659)	(1,610,425)	(97,560)	-	(5,723,676)	(219,552)	(1,208,334)	(102,440)	-	(16,088,518)
2013 Ending Balance	**28,860,274**	**15,497,386**	**8,290,087**	**6,441,700**	**642,270**	**-**	**37,680,866**	**1,445,382**	**3,423,613**	**674,397**	**-**	**102,955,974**
2014 Beginning Balance	28,860,274	15,497,386	8,290,087	6,441,700	642,270	-	37,680,866	1,445,382	3,423,613	674,397	-	102,955,974
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(4,383,839)	(2,354,033)	(388,659)	(1,610,425)	(97,560)	-	(5,723,676)	(219,552)	(1,208,334)	(102,440)	-	(16,088,518)
2014 Ending Balance	**24,476,435**	**13,143,352**	**7,901,428**	**4,831,275**	**544,710**	**-**	**31,957,190**	**1,225,830**	**2,215,279**	**571,956**	**-**	**86,867,456**
2015 Beginning Balance	24,476,435	13,143,352	7,901,428	4,831,275	544,710	(521,544)	31,957,190	1,225,830	2,215,279	571,956	(665,252)	85,680,660
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(4,383,839)	(2,354,033)	(388,659)	(1,610,425)	(97,560)	130,386	(5,723,676)	(219,552)	(1,208,334)	(102,440)	166,313	(15,791,819)
2015 Ending Balance	**20,092,596**	**10,789,319**	**7,512,769**	**3,220,850**	**447,150**	**(391,158)**	**26,233,515**	**1,006,278**	**1,006,945**	**469,516**	**(498,939)**	**69,888,842**
2016 Beginning Balance	20,092,596	10,789,319	7,512,769	3,220,850	447,150	(391,158)	26,233,515	1,006,278	1,006,945	469,516	(498,939)	69,888,842
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(4,383,839)	(2,354,033)	(388,659)	(1,610,425)	(97,560)	260,772	(5,723,676)	(219,552)	(534,119)	(102,440)	332,626	(14,820,904)
2016 Ending Balance	**15,708,757**	**8,435,286**	**7,124,110**	**1,610,425**	**349,590**	**(130,386)**	**20,509,839**	**786,727**	**472,826**	**367,076**	**(166,313)**	**55,067,937**
2017 Beginning Balance	15,708,757	8,435,286	7,124,110	1,610,425	349,590	(130,386)	20,509,839	786,727	472,826	367,076	(166,313)	55,067,937
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(4,383,839)	(2,354,033)	(388,659)	(1,610,425)	(97,560)	130,386	(5,723,676)	(219,552)	(472,826)	(102,440)	166,313	(15,056,311)
2017 Ending Balance	**11,324,918**	**6,081,253**	**6,735,451**	**-**	**252,030**	**-**	**14,786,163**	**567,175**	**-**	**264,636**	**-**	**40,011,626**
2018 Beginning Balance	11,324,918	6,081,253	6,735,451	-	252,030	-	14,786,163	567,175	-	264,636	-	40,011,626
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(4,383,839)	(2,354,033)	(388,659)	-	(97,560)	-	(5,723,676)	(219,552)	-	(102,440)	-	(13,269,759)
2018 Ending Balance	**6,941,079**	**3,727,219**	**6,346,792**	**-**	**154,470**	**-**	**9,062,487**	**347,623**	**-**	**162,196**	**-**	**26,741,868**
2019 Beginning Balance	6,941,079	3,727,219	6,346,792	-	154,470	-	9,062,487	347,623	-	162,196	-	26,741,868
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(4,383,840)	(2,354,033)	(388,659)	-	(97,560)	-	(5,723,677)	(219,552)	-	(102,440)	-	(13,269,760)
2019 Ending Balance	**2,557,239**	**1,373,186**	**5,958,133**	**-**	**56,910**	**-**	**3,338,811**	**128,072**	**-**	**59,757**	**-**	**13,472,108**
2020 Beginning Balance	2,557,239	1,373,186	5,958,133	-	56,910	-	3,338,811	128,072	-	59,757	-	13,472,108
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	(2,557,239)	(1,373,186)	(388,659)	-	(56,910)	-	(3,338,811)	(128,072)	-	(59,757)	-	(7,902,634)
2020 Ending Balance	**-**	**-**	**5,569,474**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5,569,474**
2021 Beginning Balance	-	-	5,569,474	-	-	-	-	-	-	-	-	5,569,474
Additions	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	(388,659)	-	-	-	-	-	-	-	-	(388,659)
2021 Ending Balance	**-**	**-**	**5,180,815**	**-**	**-**	**-**	**-**	**-**	**-**	[illegible]	[illegible]	**5,180,815**

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2014-2021 – Amortization of Regulatory Assets Detail

DESCRIPTION	
Winter 2009 Ice Storm:	Original reg asset total = $101,075,150, amortized monthly over 10 years, from August 2010 - July 2020
	LGE: 43%, beginning balance = $43.7M (electric) and $167.7k (gas) -- $2.6M per year
	KU: 57%, beginning balance = $57.2M -- $3.3M per year
2009 Wind Storm:	Original reg asset total = $25,735,849, amortized monthly over 10 years, from August 2010 - July 2020
	LGE: 91%, beginning balance = $23.5M -- $1.4M per year
	KU: 9%, beginning balance = $2.2M -- $128k per year
CMRG:	Original reg asset total = $2,000,000, amortized over 10 years, from August 2010 - July 2010
	LGE: 49%, beginning balance = $975.6k -- $97.5k per year
	KU: 51%, beginning balance = $1.02M -- $102k per year
Summer Storm:	Original reg asset total = $8,052,125, amortized monthly over 5 years, from January 2013 - December 2017
	LGE: 100%, $389k per year
Virginia Mountain Storm:	Original reg asset total = $5,041,670, originally amortized over 5 years, from November 2011 - October 2016
	In Feb 2016, after the Rate Case, the amortization period was extended an additional 14 months to Dec 2017.
	KU: 100%, $1.2M per year
Wachovia Swap Termination:	Original reg asset total = $9,303,396, amortized over 24.75 years, from August 2010 - July 2013 (assumption was new calc would begin in month 37 after next rate case)
	LGE: 100%, 80% electric/20% gas, $258,476 per year
	As a result of the 2012 Rate Case, the amortization for this reg asset was revised to 22.33 years, from January 2013 - April 2035
	LGE: 100%, 79% electric/21% gas, $388,659 per year
MISO Exit Fee:	Per S Cummins: Combined balance as of 6/30/15 = $1,186,796.17, amortized over 2 years from July 2015 - June 2017
	LGE: Total = $521,544.17, $260,772.09 per year
	KU: Total = $665,252.00, $332,626 per year

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Corporate Cost Center Other Expenses 2015-2021

	2015-2021 Annual OTHER Expenses						
	2015	2016	2017	2018	2019	2020	2021
<u>Nonlabor Categories:</u>							
Company Meters	(234)	(143)	(229)	(229)	(229)	(229)	(229)
Stores Freight	249	145	252	254	257	259	262
Insurance Claims/Settlements	(19)	842	100	102	104	106	107
Bad Debt	(493)	153	-	-	-	-	-
TCRSG Admin Agreement	211	249	223	227	232	236	241
ServCo Depreciation	866	1,068	1,398	1,400	1,400	303	171
PeopleSoft Time System	-	2,000	-	-	-	-	-
Other	(430)	345	-	-	-	-	-
Total	151	4,658	1,743	1,753	1,763	675	552

LG&E KU PPL companies

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(d)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The utility's annual and monthly budget for the twelve (12) months preceding the filing date, the base period, and forecasted period.

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2016.

Louisville Gas and Electric Company
Case No. 2016-00371
Annual and Monthly Budget for years 2015 - 2018
Base Period: Twelve Months Ended February 28, 2017
Forecasted Test Period: Twelve Months Ended June 30, 2018

2015 Budget - Louisville Gas and Electric Company

Total Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	98,946,029	90,602,096	88,074,450	84,192,883	90,162,316	105,590,772	118,725,546	120,700,754	101,671,791	90,674,339	88,656,600	98,003,418	1,176,000,995
Gas Operating Revenues	57,779,750	51,075,405	38,197,619	23,743,629	17,357,008	13,204,211	12,845,488	13,261,176	13,876,018	18,561,090	31,355,439	50,926,056	342,182,888
Total Operating Revenues	156,725,779	141,677,501	126,272,069	107,936,512	107,519,324	118,794,983	131,571,033	133,961,930	115,547,809	109,235,429	120,012,039	148,929,474	1,518,183,883
Operating Expenses													
Fuel for Electric Generation	35,281,257	29,988,677	29,973,668	28,243,865	26,557,950	31,512,460	34,845,962	35,957,621	28,068,453	28,937,876	28,514,566	31,170,072	369,052,426
Power Purchased	4,152,438	4,093,109	3,570,714	3,904,995	5,678,929	6,162,638	7,075,780	6,866,229	5,584,640	4,170,775	4,293,160	5,376,675	60,930,081
Gas Supply Expenses	34,150,532	29,648,988	20,864,881	11,009,183	6,606,288	3,638,567	3,052,366	3,179,579	3,656,707	6,506,164	15,163,174	28,440,128	165,916,557
Other Operation Expenses	22,997,846	21,577,701	22,662,758	24,503,887	21,429,560	22,494,022	22,614,866	22,568,919	22,547,016	21,702,383	20,620,405	22,646,430	268,365,793
Maintenance	7,258,433	7,489,590	9,948,085	22,051,273	9,209,544	8,345,188	8,581,641	8,049,232	8,430,786	12,754,641	7,951,976	7,244,887	117,315,275
Depreciation & Amortization Expense	14,018,554	14,037,804	14,085,615	14,133,715	13,724,494	13,344,399	13,415,358	13,481,455	13,556,203	13,610,635	13,763,537	14,022,651	165,194,420
Current Income Taxes	12,149,066	10,595,987	6,587,115	(1,373,410)	6,482,573	9,742,334	13,355,407	14,080,583	9,892,576	4,689,929	7,965,921	11,810,713	105,978,792
Property and Other Taxes	3,230,747	3,233,237	3,230,426	3,232,285	3,232,446	3,231,654	3,235,135	3,235,825	3,235,108	3,234,601	3,237,841	3,237,822	38,807,127
Amortization of Investment Tax Credit	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(1,338,634)
Total Operating Expenses	133,127,320	120,553,539	110,811,709	105,594,239	92,810,232	98,359,709	106,064,962	107,307,889	94,859,936	95,495,451	101,399,027	123,837,825	1,290,221,837
Net Operating Income	23,598,460	21,123,961	15,460,360	2,342,274	14,709,092	20,435,274	25,506,072	26,654,041	20,687,873	13,739,978	18,613,012	25,091,650	227,962,046
Other Income less deductions	(241,414)	(73,008)	(120,741)	(353,104)	(93,188)	(95,584)	(68,124)	(110,928)	(97,246)	(77,910)	(50,309)	(106,897)	(1,488,452)
Income before Interest Charges	23,357,045	21,050,954	15,339,619	1,989,170	14,615,904	20,339,690	25,437,948	26,543,113	20,590,627	13,662,068	18,562,703	24,984,752	226,473,593
Interest Charges	4,390,518	4,355,432	4,375,246	4,374,005	4,401,478	4,394,277	4,403,337	4,412,277	4,410,891	6,248,059	5,975,512	5,801,862	57,542,894
Net Income	18,966,528	16,695,521	10,964,373	(2,384,835)	10,214,426	15,945,413	21,034,611	22,130,836	16,179,736	7,414,009	12,587,191	19,182,890	168,930,700

2015 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	98,946,029	90,602,096	88,074,450	84,192,883	90,162,316	105,590,772	118,725,546	120,700,754	101,671,791	90,674,339	88,656,600	98,003,418	1,176,000,995
Total Operating Revenues	98,946,029	90,602,096	88,074,450	84,192,883	90,162,316	105,590,772	118,725,546	120,700,754	101,671,791	90,674,339	88,656,600	98,003,418	1,176,000,995
Operating Expenses													
Fuel for Electric Generation	35,281,257	29,988,677	29,973,668	28,243,865	26,557,950	31,512,460	34,845,962	35,957,621	28,068,453	28,937,876	28,514,566	31,170,072	369,052,426
Power Purchased	4,152,438	4,093,109	3,570,714	3,904,995	5,678,929	6,162,638	7,075,780	6,866,229	5,584,640	4,170,775	4,293,160	5,376,675	60,930,081
Other Operation Expenses	18,281,570	17,176,937	18,149,383	20,029,922	16,902,611	17,789,194	17,887,644	17,786,853	17,780,709	16,915,447	16,025,234	17,639,772	212,365,277
Maintenance	5,762,839	6,086,887	8,421,869	20,270,393	7,509,579	6,592,373	6,655,394	6,283,808	6,541,852	10,192,270	6,308,015	5,624,242	96,249,522
Depreciation & Amortization Expense	11,514,734	11,524,599	11,559,542	11,593,283	11,165,279	10,764,162	10,817,548	10,867,139	10,925,157	10,961,825	11,100,753	11,326,920	134,120,940
Current Income Taxes	6,964,015	6,110,209	3,848,522	(2,282,000)	6,344,138	10,210,339	13,770,819	14,349,689	10,204,486	4,652,319	5,872,584	7,468,231	87,513,351
Property and Other Taxes	2,480,141	2,482,131	2,457,957	2,459,426	2,459,553	2,458,928	2,461,574	2,462,119	2,461,553	2,461,152	2,463,712	2,463,697	29,571,945
Amortization of Investment Tax Credit	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(1,260,914)
Total Operating Expenses	84,331,918	77,357,472	77,876,579	84,114,808	76,512,964	85,385,018	93,409,644	94,468,382	81,461,774	78,186,587	74,472,948	80,964,533	988,542,628
Net Operating Income - Electric	14,614,112	13,244,624	10,197,871	78,076	13,649,352	20,205,754	25,315,901	26,232,372	20,210,018	12,487,751	14,183,652	17,038,885	187,458,367

2015 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Gas Operating Revenues	57,779,750	51,075,405	38,197,619	23,743,629	17,357,008	13,204,211	12,845,488	13,261,176	13,876,018	18,561,090	31,355,439	50,926,056	342,182,888
Total Operating Revenues	57,779,750	51,075,405	38,197,619	23,743,629	17,357,008	13,204,211	12,845,488	13,261,176	13,876,018	18,561,090	31,355,439	50,926,056	342,182,888
Operating Expenses													
Gas Supply Expenses	34,150,532	29,648,988	20,864,881	11,009,183	6,606,288	3,638,567	3,052,366	3,179,579	3,656,707	6,506,164	15,163,174	28,440,128	165,916,557
Other Operation Expenses	4,716,276	4,400,764	4,513,376	4,473,965	4,526,949	4,704,828	4,727,222	4,782,066	4,766,306	4,786,936	4,595,171	5,006,658	56,000,517
Maintenance	1,495,594	1,402,703	1,526,216	1,780,879	1,699,965	1,752,815	1,926,246	1,765,424	1,888,934	2,562,371	1,643,960	1,620,645	21,065,753
Depreciation & Amortization	2,503,820	2,513,205	2,526,073	2,540,433	2,559,215	2,580,237	2,597,810	2,614,316	2,631,046	2,648,809	2,662,784	2,695,731	31,073,479
Current Income Taxes	5,185,051	4,485,778	2,738,592	908,590	138,434	(468,006)	(415,411)	(269,106)	(311,910)	37,611	2,093,337	4,342,482	18,465,441
Property and Other Taxes	750,606	751,106	772,469	772,859	772,893	772,726	773,561	773,706	773,555	773,449	774,129	774,125	9,235,182
Amortization of Investment Tax Credit	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(77,720)
Total Gas Operating Expenses and Taxes	48,795,402	43,196,067	32,935,130	21,479,431	16,297,268	12,974,691	12,655,317	12,839,506	13,398,162	17,308,863	26,926,079	42,873,291	301,679,210
Net Operating Income - Gas	8,984,348	7,879,338	5,262,489	2,264,198	1,059,739	229,520	190,170	421,669	477,855	1,252,226	4,429,360	8,052,765	40,503,678

2016 Budget - Louisville Gas and Electric Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Total 12 months Preceding Filing Date[1]
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	99,158,234	91,430,985	90,632,008	87,606,851	91,545,191	108,094,283	118,504,174	120,617,636	101,097,839	88,770,189	85,440,986	95,311,468	1,178,209,845	1,184,117,409
Gas Operating Revenues	56,213,748	48,761,234	37,248,519	22,476,485	16,900,924	13,123,037	12,392,842	12,795,055	13,415,522	18,275,594	30,807,633	48,829,655	331,240,247	333,884,454
Total Operating Revenues	155,371,982	140,192,219	127,880,527	110,083,337	108,446,115	121,217,319	130,897,016	133,412,691	114,513,360	107,045,783	116,248,619	144,141,124	1,509,450,092	1,518,001,862
Operating Expenses														
Fuel for Electric Generation	31,159,867	27,562,660	27,896,606	27,374,189	23,181,153	28,666,872	32,661,251	33,512,746	26,983,160	23,339,893	22,268,693	28,503,199	333,110,289	342,023,035
Power Purchased	4,892,537	4,647,913	4,247,615	3,833,752	6,378,895	6,941,448	6,602,971	6,358,038	4,647,780	5,088,842	4,601,117	4,072,809	62,313,717	63,309,626
Gas Supply Expenses	29,730,076	25,156,241	17,999,634	8,837,256	5,272,541	2,694,827	2,130,869	2,279,646	2,670,919	5,509,270	13,539,289	25,265,685	141,086,255	145,884,583
Other Operation Expenses	21,022,003	21,296,888	21,805,092	19,890,919	21,206,659	21,968,539	21,633,524	23,085,814	22,366,747	20,873,897	20,478,935	21,311,555	256,940,571	258,416,916
Maintenance	7,473,362	8,132,568	9,101,579	13,382,133	10,533,059	9,222,472	8,565,060	8,754,388	8,628,476	12,074,778	12,373,938	7,606,497	115,848,310	111,064,738
Depreciation & Amortization Expense	14,167,541	14,203,347	14,244,631	14,288,207	14,334,262	14,646,772	14,961,089	15,020,342	15,080,342	15,138,366	15,192,908	15,392,985	176,670,793	173,871,087
Current Income Taxes	14,809,257	11,687,446	9,116,068	5,204,801	7,132,765	10,634,682	13,631,595	13,656,200	9,452,660	6,140,106	7,243,507	12,521,191	121,230,278	121,242,213
Property and Other Taxes	3,405,692	3,404,778	3,389,816	3,402,230	3,401,268	3,405,347	3,415,965	3,393,886	3,404,404	3,403,714	3,408,794	3,422,008	40,857,902	40,502,763
Amortization of Investment Tax Credit	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(1,229,230)	(1,247,464)
Total Operating Expenses	126,557,900	115,989,405	107,698,604	96,111,052	91,338,167	98,078,524	103,499,888	105,958,623	93,132,052	91,466,431	99,004,746	117,993,493	1,246,828,885	1,255,067,498
Net Operating Income	28,814,082	24,202,814	20,181,923	13,972,285	17,107,948	23,138,795	27,397,128	27,454,068	21,381,308	15,579,352	17,243,873	26,147,631	262,621,207	262,934,365
Other Income less deductions	(138,418)	(69,488)	(183,711)	(80,833)	(62,155)	(65,056)	(43,044)	(54,796)	(54,564)	(62,175)	(79,927)	(60,743)	(954,909)	(971,445)
Income before Interest Charges	28,675,664	24,133,326	19,998,212	13,891,452	17,045,793	23,073,739	27,354,084	27,399,272	21,326,744	15,517,177	17,163,946	26,086,888	261,666,298	261,962,920
Interest Charges	5,908,531	5,889,884	5,878,380	5,895,680	5,912,168	5,919,938	5,916,831	5,969,049	5,971,391	5,941,658	5,955,560	5,963,566	71,122,636	70,980,884
Net Income	22,767,134	18,243,443	14,119,832	7,995,772	11,133,625	17,153,801	21,437,253	21,430,223	15,355,353	9,575,519	11,208,385	20,123,322	190,543,662	190,982,036

Total 12 months Preceding Filing Date[1] - Sum of November and December 2015 Budget plus January through October of the 2016 Budget

2016 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	99,158,234	91,430,985	90,632,008	87,606,851	91,545,191	108,094,283	118,504,174	120,617,636	101,097,839	88,770,189	85,440,986	95,311,468	1,178,209,845
Total Operating Revenues	99,158,234	91,430,985	90,632,008	87,606,851	91,545,191	108,094,283	118,504,174	120,617,636	101,097,839	88,770,189	85,440,986	95,311,468	1,178,209,845
Operating Expenses													
Fuel for Electric Generation	31,159,867	27,562,660	27,896,606	27,374,189	23,181,153	28,666,872	32,661,251	33,512,746	26,983,160	23,339,893	22,268,693	28,503,199	333,110,289
Power Purchased	4,892,537	4,647,913	4,247,615	3,833,752	6,378,895	6,941,448	6,602,971	6,358,038	4,647,780	5,088,842	4,601,117	4,072,809	62,313,717
Other Operation Expenses	16,428,281	16,579,878	16,865,576	15,467,816	16,479,704	17,338,231	17,212,648	18,145,365	17,536,914	16,156,075	15,773,144	16,538,674	200,522,306
Maintenance	6,276,700	6,962,172	7,845,974	11,930,500	9,056,242	7,883,380	6,922,825	6,955,509	7,199,111	10,636,823	10,967,054	6,344,360	98,980,649
Depreciation & Amortization Expense	11,471,841	11,495,569	11,523,367	11,552,375	11,583,558	11,876,140	12,170,617	12,212,473	12,255,624	12,295,744	12,335,410	12,486,662	143,259,380
Current Income Taxes	8,532,525	6,596,979	5,838,337	3,993,085	6,845,513	10,766,145	13,820,852	14,017,222	9,579,660	5,406,900	4,742,343	7,602,048	97,741,608
Property and Other Taxes	2,566,972	2,566,034	2,551,706	2,563,298	2,562,805	2,566,770	2,575,913	2,554,732	2,564,859	2,564,057	2,568,949	2,581,632	30,787,726
Amortization of Investment Tax Credit	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(1,168,810)
Total Operating Expenses	81,231,322	76,313,804	76,671,780	76,617,614	75,990,469	85,941,585	91,869,677	93,658,684	80,669,707	75,390,933	73,159,310	78,031,983	965,546,866
Net Operating Income - Electric	17,926,913	15,117,181	13,960,228	10,989,238	15,554,722	22,152,698	26,634,498	26,958,952	20,428,132	13,379,256	12,281,676	17,279,486	212,662,979

2016 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Gas Operating Revenues	56,213,748	48,761,234	37,248,519	22,476,485	16,900,924	13,123,037	12,392,842	12,795,055	13,415,522	18,275,594	30,807,633	48,829,655	331,240,247
Total Operating Revenues	56,213,748	48,761,234	37,248,519	22,476,485	16,900,924	13,123,037	12,392,842	12,795,055	13,415,522	18,275,594	30,807,633	48,829,655	331,240,247
Operating Expenses													
Gas Supply Expenses	29,730,076	25,156,241	17,999,634	8,837,256	5,272,541	2,694,827	2,130,869	2,279,646	2,670,919	5,509,270	13,539,289	25,265,685	141,086,255
Other Operation Expenses	4,593,721	4,717,010	4,939,516	4,423,103	4,726,955	4,630,309	4,420,876	4,940,449	4,829,833	4,717,823	4,705,791	4,772,881	56,418,265
Maintenance	1,196,662	1,170,396	1,255,605	1,451,633	1,476,817	1,339,092	1,642,235	1,798,879	1,429,365	1,437,955	1,406,884	1,262,137	16,867,661
Depreciation & Amortization	2,695,701	2,707,778	2,721,263	2,735,833	2,750,705	2,770,632	2,790,472	2,807,869	2,824,718	2,842,622	2,857,498	2,906,323	33,411,413
Current Income Taxes	6,276,732	5,090,467	3,277,731	1,211,716	287,252	(131,463)	(189,257)	(361,022)	(127,000)	733,206	2,501,164	4,919,143	23,488,670
Property and Other Taxes	838,720	838,744	838,110	838,932	838,463	838,577	840,052	839,154	839,545	839,657	839,845	840,376	10,070,176
Amortization of Investment Tax Credit	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(60,420)
Total Gas Operating Expenses and Taxes	45,326,578	39,675,601	31,026,824	19,493,438	15,347,698	12,136,939	11,630,211	12,299,939	12,462,345	16,075,498	25,845,436	39,961,511	281,282,019
Net Operating Income - Gas	10,887,170	9,085,633	6,221,695	2,983,047	1,553,226	986,097	762,631	495,115	953,177	2,200,096	4,962,197	8,868,145	49,958,228

Total 12 months Preceding Filing Date[1] - Sum of November and December 2015 Budget plus January through October of the 2016 Budget

2017 Budget - Louisville Gas and Electric Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Budgeted Base Period[1] 2/28/2017
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	98,974,333	89,703,265	89,081,730	81,556,030	92,962,209	106,098,249	115,475,859	116,478,182	96,922,988	85,526,662	84,873,769	98,928,568	1,156,581,843	1,176,298,223
Gas Operating Revenues	54,675,256	49,821,382	40,033,632	24,366,128	17,974,593	14,155,640	13,179,810	13,085,204	13,573,281	16,341,570	27,390,079	43,174,847	327,771,422	330,761,903
Total Operating Revenues	153,649,589	139,524,647	129,115,362	105,922,157	110,936,802	120,253,889	128,655,669	129,563,386	110,496,268	101,868,232	112,263,848	142,103,416	1,484,353,265	1,507,060,126
Operating Expenses														
Fuel for Electric Generation	29,415,308	26,091,161	26,468,212	19,326,363	24,710,873	27,585,640	29,423,353	30,436,447	23,718,209	20,591,549	21,291,536	28,268,867	307,327,519	329,894,231
Power Purchased	4,342,058	4,059,631	4,048,833	5,582,417	4,777,430	5,835,712	5,838,211	5,655,530	4,685,885	4,781,801	4,354,422	4,297,481	58,259,411	61,174,955
Gas Supply Expenses	28,065,204	25,886,831	20,449,070	10,494,859	5,976,729	3,212,583	2,514,383	2,259,616	2,561,506	3,457,559	10,335,428	20,283,093	135,496,860	140,151,972
Other Operation Expenses	20,577,725	20,193,790	21,285,215	19,397,601	20,942,259	22,486,752	22,335,816	23,500,209	22,546,749	22,127,151	20,745,919	21,991,739	258,130,924	255,393,195
Maintenance	7,370,601	7,366,739	8,698,677	12,413,819	9,006,645	7,999,692	7,962,866	8,622,374	9,474,033	12,213,686	16,164,827	8,138,442	115,432,401	114,979,720
Depreciation & Amortization Expense	14,985,902	15,010,561	15,038,776	15,074,921	15,120,970	15,164,735	18,484,022	18,562,284	18,669,611	18,750,109	18,852,036	19,006,307	202,720,234	178,296,367
Regulatory Debits	51,101	52,244	53,391	56,261	59,141	62,031	67,698	73,385	79,092	84,255	89,436	94,636	822,673	103,345
Current Income Taxes	15,311,555	12,231,346	8,950,890	5,482,805	8,129,552	10,834,024	12,664,719	12,059,633	7,062,129	3,849,898	4,062,049	11,430,989	112,069,590	122,276,476
Property and Other Taxes	3,671,843	3,682,449	3,663,060	3,682,228	3,664,166	3,671,941	3,684,958	3,661,087	3,679,306	3,660,959	3,673,524	3,689,924	44,085,439	41,401,723
Amortization of Investment Tax Credit	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(92,253)	(1,107,030)	(1,208,863)
Total Operating Expenses	123,699,042	114,482,499	108,563,871	91,419,021	92,295,512	96,760,858	102,883,773	104,738,314	92,384,268	89,424,714	99,476,924	117,109,226	1,233,238,021	1,242,463,121
Net Operating Income	29,950,547	25,042,148	20,551,491	14,503,137	18,641,290	23,493,030	25,771,896	24,825,072	18,112,001	12,443,518	12,786,924	24,994,190	251,115,244	264,597,005
Other Income less deductions	(321,194)	(261,746)	(445,356)	(160,646)	(96,799)	(108,978)	(45,212)	(87,070)	(144,227)	(112,016)	(206,407)	(194,519)	(2,184,171)	(1,329,943)
Income before Interest Charges	29,629,353	24,780,401	20,106,135	14,342,490	18,544,491	23,384,053	25,726,683	24,738,002	17,967,774	12,331,502	12,580,517	24,799,671	248,931,073	263,267,062
														-
Interest Charges	5,800,306	5,729,972	5,778,942	5,790,855	5,771,777	5,762,654	5,779,025	5,782,606	6,306,118	6,296,035	6,306,215	6,326,165	71,430,671	70,854,500
Net Income	23,829,047	19,050,429	14,327,193	8,551,635	12,772,713	17,621,398	19,947,659	18,955,396	11,661,656	6,035,468	6,274,302	18,473,506	177,500,402	192,412,562

Budgeted Base Period[1] = The sum of March 2016 through December 2016 totals per the 2016 Budget plus January 2017 through February 2017 totals per the 2017 Budget excluding rate case activities.

2017 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Budgeted Base Period[1] 2/28/2017
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	98,974,333	89,703,265	89,081,730	81,556,030	92,962,209	106,098,249	115,475,859	116,478,182	96,922,988	85,526,662	84,873,769	98,928,568	1,156,581,843	1,176,298,223
Total Operating Revenues	98,974,333	89,703,265	89,081,730	81,556,030	92,962,209	106,098,249	115,475,859	116,478,182	96,922,988	85,526,662	84,873,769	98,928,568	1,156,581,843	1,176,298,223
Operating Expenses														
Fuel for Electric Generation	29,415,308	26,091,161	26,468,212	19,326,363	24,710,873	27,585,640	29,423,353	30,436,447	23,718,209	20,591,549	21,291,536	28,268,867	307,327,519	329,894,231
Power Purchased	4,342,058	4,059,631	4,048,833	5,582,417	4,777,430	5,835,712	5,838,211	5,655,530	4,685,885	4,781,801	4,354,422	4,297,481	58,259,411	61,174,955
Other Operation Expenses	15,836,624	15,512,983	16,261,660	14,878,935	16,063,848	17,467,875	17,476,209	18,233,667	17,451,799	16,840,172	15,739,299	17,104,666	198,867,737	198,863,754
Maintenance	5,927,254	6,082,099	7,242,140	11,021,699	7,424,019	6,558,957	6,526,421	6,667,458	7,927,769	10,488,697	14,617,549	6,738,586	97,222,648	97,751,131
Depreciation & Amortization Expense	11,950,214	11,964,333	11,980,233	12,002,872	12,035,576	12,066,141	15,345,268	15,390,930	15,454,340	15,504,710	15,588,678	15,717,437	165,000,731	144,206,517
Regulatory Debits	51,101	52,244	53,391	56,261	59,141	62,031	67,698	73,385	79,092	84,255	89,436	94,636	822,673	103,345
Current Income Taxes	9,284,284	7,159,266	5,792,460	4,318,282	7,911,327	11,043,705	12,922,390	12,627,636	7,397,542	3,598,497	2,017,885	7,037,299	91,110,573	99,055,654
Property and Other Taxes	2,760,869	2,771,057	2,752,456	2,770,495	2,753,549	2,761,262	2,772,999	2,749,815	2,767,358	2,749,536	2,761,727	2,777,795	33,148,919	31,186,647
Amortization of Investment Tax Credit	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(88,376)	(1,060,510)	(1,150,760)
Total Operating Expenses	79,479,336	73,604,399	74,511,010	69,868,947	75,647,387	83,292,948	90,284,173	91,746,493	79,393,619	74,550,842	76,372,157	81,948,392	950,699,702	961,085,474
Net Operating Income - Electric	19,494,997	16,098,866	14,570,720	11,687,083	17,314,822	22,805,301	25,191,686	24,731,689	17,529,369	10,975,820	8,501,612	16,980,177	205,882,142	215,212,749

2017 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Budgeted Base Period[1] 2/28/2017
INCOME STATEMENT														
Operating Revenues														
Gas Operating Revenues	54,675,256	49,821,382	40,033,632	24,366,128	17,974,593	14,155,640	13,179,810	13,085,204	13,573,281	16,341,570	27,390,079	43,174,847	327,771,422	330,761,903
Total Operating Revenues	54,675,256	49,821,382	40,033,632	24,366,128	17,974,593	14,155,640	13,179,810	13,085,204	13,573,281	16,341,570	27,390,079	43,174,847	327,771,422	330,761,903
Operating Expenses														
Gas Supply Expenses	28,065,204	25,886,831	20,449,070	10,494,859	5,976,729	3,212,583	2,514,383	2,259,616	2,561,506	3,457,559	10,335,428	20,283,093	135,496,860	140,151,972
Other Operation Expenses	4,741,100	4,680,806	5,023,555	4,518,666	4,878,410	5,018,877	4,859,607	5,266,542	5,094,950	5,286,979	5,006,620	4,887,073	59,263,187	56,529,441
Maintenance	1,443,347	1,284,640	1,456,537	1,392,120	1,582,626	1,440,735	1,436,445	1,954,916	1,546,264	1,724,989	1,547,278	1,399,856	18,209,753	17,228,589
Depreciation & Amortization	3,035,688	3,046,228	3,058,543	3,072,049	3,085,394	3,098,594	3,138,754	3,171,354	3,215,271	3,245,399	3,263,359	3,288,870	37,719,503	34,089,850
Regulatory Debits	-	-	-	-	-	-	-	-	-	-	-	-	-	
Current Income Taxes	6,027,271	5,072,080	3,158,430	1,164,523	218,226	(209,681)	(257,672)	(568,003)	(335,413)	251,400	2,044,164	4,393,690	20,959,017	23,220,822
Property and Other Taxes	910,974	911,392	910,604	911,733	910,616	910,679	911,958	911,271	911,948	911,422	911,796	912,128	10,936,520	10,215,076
Amortization of Investment Tax Credit	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(46,520)	(58,103)
Total Gas Operating Expenses and Taxes	44,219,706	40,878,100	34,052,862	21,550,074	16,648,125	13,467,910	12,599,600	12,991,821	12,990,648	14,873,872	23,104,768	35,160,834	282,538,320	281,377,647
Net Operating Income - Gas	10,455,550	8,943,281	5,980,771	2,816,054	1,326,467	687,729	580,210	93,384	582,632	1,467,698	4,285,312	8,014,014	45,233,102	49,384,256

Budgeted Base Period[1] = The sum of March 2016 through December 2016 totals per the 2016 Budget plus January 2017 through February 2017 totals per the 2017 Budget excluding rate case activities.

2018 Budget - Louisville Gas and Electric Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Test Year 6/30/2018
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	100,586,409	91,549,877	92,372,071	85,212,103	95,362,297	108,363,358	116,758,927	118,012,633	99,275,232	87,664,368	87,824,218	100,292,259	1,183,273,751	1,171,652,143
Gas Operating Revenues	54,967,052	50,255,793	40,393,365	24,526,835	18,205,553	14,454,577	13,620,229	13,517,117	13,992,124	16,697,584	27,611,224	43,073,614	331,315,068	329,547,967
Total Operating Revenues	155,553,462	141,805,670	132,765,436	109,738,938	113,567,850	122,817,934	130,379,156	131,529,750	113,267,356	104,361,952	115,435,442	143,365,873	1,514,588,820	1,501,200,109
Operating Expenses														
Fuel for Electric Generation	28,837,043	25,527,386	27,471,355	22,410,543	23,935,719	27,281,145	29,256,462	29,967,544	24,513,248	20,902,463	22,618,616	27,942,335	310,663,857	309,193,152
Power Purchased	4,238,969	4,177,583	4,249,934	3,945,041	5,271,245	5,495,749	5,712,012	5,722,181	4,477,982	4,830,055	4,411,119	4,299,775	56,831,642	56,991,850
Gas Supply Expenses	28,015,549	25,955,761	20,411,360	10,242,771	5,775,158	3,079,831	2,420,760	2,159,450	2,458,116	3,302,311	10,086,828	19,767,979	133,675,874	134,892,015
Other Operation Expenses	21,997,661	21,293,700	22,103,422	21,237,331	22,129,580	23,147,317	23,098,842	24,155,377	22,944,937	23,210,662	21,621,684	23,085,380	270,025,893	265,156,595
Maintenance	7,521,656	7,407,860	8,908,516	15,277,162	11,236,002	8,536,796	9,458,755	8,669,832	8,689,692	14,719,250	8,967,624	8,071,601	117,464,746	121,464,220
Depreciation & Amortization Expense	19,115,927	19,131,358	19,150,243	19,173,973	19,224,727	19,308,912	19,520,894	19,730,245	19,796,365	19,846,204	19,918,919	20,452,370	234,370,136	227,429,508
Regulatory Debits	96,498	98,367	100,242	103,550	106,869	110,200	115,251	120,321	125,410	131,973	138,561	145,173	1,392,415	1,104,229
Current Income Taxes	13,801,941	10,890,952	7,593,496	2,748,396	6,055,065	9,704,599	11,845,986	11,926,598	7,516,076	2,744,480	6,722,140	11,122,345	102,672,076	101,923,867
Property and Other Taxes	3,906,563	3,924,443	3,912,924	3,918,012	3,905,959	3,923,201	3,921,323	3,906,214	3,930,445	3,901,458	3,920,998	3,934,980	47,006,521	45,540,857
Amortization of Investment Tax Credit	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(80,815)	(969,780)	(1,038,405)
Total Operating Expenses	127,450,993	118,326,594	113,820,678	98,975,963	97,559,509	100,506,934	105,269,471	106,276,948	94,371,455	93,508,040	98,325,674	118,741,123	1,273,133,379	1,262,657,888
Net Operating Income	28,102,469	23,479,076	18,944,758	10,762,975	16,008,341	22,311,001	25,109,686	25,252,803	18,895,901	10,853,912	17,109,768	24,624,750	241,455,440	238,542,222
Other Income less deductions	(317,942)	(263,156)	(443,927)	(164,455)	(87,835)	(102,190)	(31,108)	(79,073)	(146,387)	(118,919)	(209,645)	(205,062)	(2,169,699)	(2,168,958)
Income before Interest Charges	27,784,527	23,215,920	18,500,831	10,598,520	15,920,506	22,208,811	25,078,578	25,173,730	18,749,514	10,734,993	16,900,123	24,419,689	239,285,741	236,373,264
Interest Charges	6,334,806	6,283,686	6,345,375	6,357,051	6,408,652	6,395,721	6,414,231	6,430,731	6,418,121	6,454,139	6,462,308	6,482,625	76,787,447	74,921,456
Net Income	21,449,720	16,932,233	12,155,456	4,241,468	9,511,855	15,813,090	18,664,347	18,742,999	12,331,393	4,280,854	10,437,815	17,937,064	162,498,294	161,451,808

2018 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Test Year 6/30/2018
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	100,586,409	91,549,877	92,372,071	85,212,103	95,362,297	108,363,358	116,758,927	118,012,633	99,275,232	87,664,368	87,824,218	100,292,259	1,183,273,751	1,171,652,143
Total Operating Revenues	100,586,409	91,549,877	92,372,071	85,212,103	95,362,297	108,363,358	116,758,927	118,012,633	99,275,232	87,664,368	87,824,218	100,292,259	1,183,273,751	1,171,652,143
Operating Expenses														
Fuel for Electric Generation	28,837,043	25,527,386	27,471,355	22,410,543	23,935,719	27,281,145	29,256,462	29,967,544	24,513,248	20,902,463	22,618,616	27,942,335	310,663,857	309,193,152
Power Purchased	4,238,969	4,177,583	4,249,934	3,945,041	5,271,245	5,495,749	5,712,012	5,722,181	4,477,982	4,830,055	4,411,119	4,299,775	56,831,642	56,991,850
Other Operation Expenses	16,923,680	16,350,705	16,912,160	16,325,128	16,993,995	17,983,725	18,037,192	18,779,219	17,850,457	17,607,267	16,463,349	18,028,942	208,255,818	204,335,204
Maintenance	6,007,138	6,067,842	7,466,397	13,736,468	9,512,121	7,069,893	7,066,934	7,034,475	7,157,518	12,772,229	7,365,247	6,638,291	97,894,552	102,826,340
Depreciation & Amortization Expense	15,803,572	15,813,778	15,825,744	15,840,660	15,880,972	15,945,948	16,140,807	16,334,452	16,382,083	16,419,637	16,480,808	16,936,856	193,805,317	188,112,036
Regulatory Debits	96,498	98,367	100,242	103,550	106,869	110,200	115,251	120,321	125,410	131,973	138,561	145,173	1,392,415	1,104,229
Current Income Taxes	7,965,566	5,966,102	4,501,507	1,796,807	5,989,864	9,978,109	12,505,697	12,359,841	7,748,108	2,608,268	4,677,769	6,765,523	82,863,161	81,799,203
Property and Other Taxes	2,934,989	2,952,138	2,941,171	2,945,723	2,934,491	2,951,177	2,948,538	2,933,968	2,957,070	2,929,152	2,948,095	2,961,809	35,338,321	34,238,920
Amortization of Investment Tax Credit	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(78,713)	(944,560)	(1,002,535)
Total Operating Expenses	82,728,742	76,875,186	79,389,797	77,025,207	80,546,562	86,737,231	91,704,180	93,173,287	81,133,162	78,122,330	75,024,849	83,639,990	986,100,521	977,598,400
Net Operating Income - Electric	17,857,667	14,674,691	12,982,274	8,186,897	14,815,735	21,626,127	25,054,747	24,839,346	18,142,070	9,542,038	12,799,370	16,652,268	197,173,230	194,053,743

2018 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Test Year 6/30/2018
INCOME STATEMENT														
Operating Revenues														
Gas Operating Revenues	54,967,052	50,255,793	40,393,365	24,526,835	18,205,553	14,454,577	13,620,229	13,517,117	13,992,124	16,697,584	27,611,224	43,073,614	331,315,068	329,547,967
Total Operating Revenues	54,967,052	50,255,793	40,393,365	24,526,835	18,205,553	14,454,577	13,620,229	13,517,117	13,992,124	16,697,584	27,611,224	43,073,614	331,315,068	329,547,967
Operating Expenses														
Gas Supply Expenses	28,015,549	25,955,761	20,411,360	10,242,771	5,775,158	3,079,831	2,420,760	2,159,450	2,458,116	3,302,311	10,086,828	19,767,979	133,675,874	134,892,015
Other Operation Expenses	5,073,981	4,942,995	5,191,262	4,912,203	5,135,585	5,163,592	5,061,650	5,376,158	5,094,480	5,603,395	5,158,335	5,056,438	61,770,075	60,821,390
Maintenance	1,514,518	1,340,018	1,442,119	1,540,694	1,723,881	1,466,903	2,391,821	1,635,357	1,532,174	1,947,021	1,602,377	1,433,311	19,570,194	18,637,880
Depreciation & Amortization	3,312,355	3,317,580	3,324,499	3,333,312	3,343,755	3,362,964	3,380,087	3,395,793	3,414,282	3,426,567	3,438,111	3,515,514	40,564,820	39,317,472
Regulatory Debits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current Income Taxes	5,836,375	4,924,851	3,091,989	951,589	65,201	(273,509)	(659,711)	(433,243)	(232,032)	136,211	2,044,371	4,356,822	19,808,915	20,124,664
Property and Other Taxes	971,574	972,305	971,753	972,289	971,469	972,024	972,785	972,246	973,375	972,306	972,903	973,171	11,668,200	11,301,937
Amortization of Investment Tax Credit	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(25,220)	(35,870)
Total Gas Operating Expenses and Taxes	44,722,251	41,451,408	34,430,881	21,950,756	17,012,947	13,769,703	13,565,291	13,103,661	13,238,294	15,385,710	23,300,825	35,101,132	287,032,858	285,059,489
Net Operating Income - Gas	10,244,802	8,804,385	5,962,484	2,576,078	1,192,606	684,874	54,938	413,457	753,830	1,311,874	4,310,399	7,972,482	44,282,210	44,488,479

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(e)
Sponsoring Witness: Victor A. Staffieri

Description of Filing Requirement:

A statement of attestation signed by the utility's chief officer in charge of Kentucky operations, which shall provide:

1. *That the forecast is reasonable, reliable, made in good faith, and that all basic assumptions used in the forecast have been identified and justified;*
2. *That the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for differences that exist, if applicable; and*
3. *That productivity and efficiency gains are included in the forecast.*

Response:

See attached.

STATEMENT OF ATTESTATION SIGNED BY THE UTILITY'S CHIEF OFFICER IN CHARGE OF KENTUCKY OPERATIONS

1. The forecast presented in this rate application is reasonable, reliable, made in good faith, and all basic assumptions used in the forecast have been identified and justified;

2. The forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, except for the differences that have been identified and explained in the filing requirements and schedules thereto; and

3. Productivity and efficiency gains are included in the forecast.

VICTOR A. STAFFIERI
Chairman of the Board, Chief Executive Officer and
President of Louisville Gas and Electric Company
and Kentucky Utilities Company

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15 day of November 2016.

NOTARY PUBLIC (SEAL)

My Commission Expires:

June 21, 2018

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(f)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

For each major construction project that constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast, the following information shall be filed:

1. *The date the project was started or estimated starting date;*
2. *The estimated completion date;*
3. *The total estimated cost of construction by year exclusive and inclusive of allowance for funds used during construction ("AFUDC") or interest during construction credit; and*
4. *The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit.*

Response:

See attached.

Louisville Gas and Electric Company
Case No. 2016-00371
Fully Forecasted Test Period
Summary of Electric Capital Construction Forecast which Constitute More than five (5%) of the Total and all other Projects

Year 2016

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	Mill Creek 3 - Environmental Air	3	$ 78,301,631	$ -	$ 78,301,631	$ 293,668,395	$ -	$ 293,668,395	$ 224,982,625	Jan-10	Jun-17
Trimble County	Trimble County CCRT - Landfill	N/A	$ 27,852,196	$ -	$ 27,852,196	$ 9,814,917	$ -	$ 9,814,917	$ -	Mar-16	Jul-18
	All Other Projects < 5%		$ 268,012,925	$ -	$ 268,012,925	$ 1,444,876,059	$ -	$ 1,444,876,059	$ 1,312,266,684		

Year 2017

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	Mill Creek Process Water Pond	N/A	$ 40,357,000	$ -	$ 40,357,000	$ 379,214	$ -	$ 379,214	$ -	Jun-16	Dec-19
Mill Creek	Mill Creek Gypsum Dewatering	N/A	$ 28,574,965	$ -	$ 28,574,965	$ -	$ -	$ -	$ -	Jun-16	Dec-18
	All Other Projects < 5%		$ 382,501,195	$ -	$ 382,501,195	$ 1,255,263,518	$ -	$ 1,255,263,518	$ 1,104,859,144		

Year 2018

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	Mill Creek Process Water Pond	N/A	$ 77,846,980	$ -	$ 77,846,980	$ 379,214	$ -	$ 379,214	$ -	Jun-16	Dec-19
Mill Creek	Mill Creek Gypsum Dewatering	N/A	$ 44,378,514	$ -	$ 44,378,514	$ -	$ -	$ -	$ -	Jun-16	Dec-18
NA	Advanced Metering Systems	N/A	$ 30,983,750	$ -	$ 30,983,750	$ -	$ -	$ -	$ -	Jan-17	Dec-19
	All Other Projects < 5%		$ 361,968,924	$ -	$ 361,968,924	$ 204,352,487	$ -	$ 204,352,487	$ 137,655,076		

Year 2019

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	Mill Creek Effluent Water	N/A	$ 31,495,976	$ -	$ 31,495,976	$ -	$ -	$ -	$ -	Jul-16	Dec-22
NA	Advanced Metering Systems	N/A	$ 33,488,000	$ -	$ 33,488,000	$ -	$ -	$ -	$ -	Jan-17	Dec-19
NA	TEP Trimble Co-Clfty Crk 345kV Line	N/A	$ 38,022,167	$ -	$ 38,022,167	$ -	$ -	$ -	$ -	Sep-18	Jun-21
	All Other Projects < 5%		$ 305,698,690	$ -	$ 305,698,690	$ 177,868,264	$ -	$ 177,868,264	$ 131,805,157		

Louisville Gas and Electric Company
Case No. 2016-00371
Fully Forecasted Test Period
Summary of Gas Capital Construction Forecast which Constitute More than five (5%) of the Total and all other Projects

Year 2016

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
NA	Gas Service Riser Replacement	NA	$ 23,758,928	-	$ 23,758,928	$ 61,884,402	$ -	$ 61,884,402	$ 46,641,391	Jan-13	Dec-17
NA	Downtown Main Replacement	NA	$ 8,827,538	-	$ 8,827,538	$ 33,807,389	$ -	$ 33,807,389	$ 28,740,546	Jan-04	Dec-19
NA	Large Scale Main Replacements	NA	$ 9,013,700	-	$ 9,013,700	$ 152,969,164	$ -	$ 152,969,164	$ 145,266,889	Jan-04	Dec-19
NA	Priority Main Replacement	NA	$ 5,780,302	-	$ 5,780,302	$ 33,169,443	$ -	$ 33,169,443	$ 30,483,247	Jan-04	Dec-18
	All Other Projects < 5%		$ 55,750,387	-	$ 55,750,387	$ 135,771,279	$ -	$ 135,771,279	$ 104,599,677		

Year 2017

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
NA	Gas Service Riser Replacement	NA	$ 24,001,385	-	$ 24,001,385	$ 61,884,402	$ -	$ 61,884,402	$ 46,641,391	Jan-13	Dec-17
NA	Large Scale Main Replacements	NA	$ 6,283,515	-	$ 6,283,515	$ 152,969,164	$ -	$ 152,969,164	$ 145,266,889	Jan-04	Dec-19
	All Other Projects < 5%		$ 77,951,523	-	$ 77,951,523	$ 165,039,085	$ -	$ 165,039,085	$ 138,362,190		

Year 2018

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
NA	Mt. Washington-Lebanon Junction	NA	$ 22,500,600	-	$ 22,500,600	$ 63,547	$ -	$ 63,547	$ 63,168	Jul-14	Mar-19
NA	Transmission Line Replacement	NA	$ 19,999,418	-	$ 19,999,418	$ -	$ -	$ -	$ -	Jan-17	Dec-25
NA	Advanced Metering Systems	NA	$ 13,278,750	-	$ 13,278,750	$ -	$ -	$ -	$ -	Jan-17	Dec-19
NA	Steel Service Line Replacements	NA	$ 9,415,455	-	$ 9,415,455	$ -	$ -	$ -	$ -	Jan-18	Dec-22
	All Other Projects < 5%		$ 82,052,034	-	$ 82,052,034	$ 314,378,796	$ -	$ 314,378,796	$ 282,997,367		

Year 2019

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/16 Without AFUDC	AFUDC	Inception-to-Date 8/31/16 With AFUDC	Inception-to-Date 12/31/15 With AFUDC	Expected Start Date	Expected Completion Date
NA	Transmission Line Replacement	NA	$ 37,499,853	-	$ 37,499,853	$ -	$ -	$ -	$ -	Jan-17	Dec-25
NA	Advanced Metering Systems	NA	$ 14,352,000	-	$ 14,352,000	$ -	$ -	$ -	$ -	Jan-17	Dec-19
NA	Booster Compressor Phase 2	NA	$ 10,001,313	-	$ 10,001,313	$ -	$ -	$ -	$ -	Jan-18	Dec-20
NA	Steel Service Line Replacements	NA	$ 9,705,750	-	$ 9,705,750	$ -	$ -	$ -	$ -	Jan-18	Dec-22
	All Other Projects <5%		$ 72,919,587	-	$ 72,919,587	$ 280,023,753	$ -	$ 280,023,753	$ 251,712,311		

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(g)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

For all construction projects that constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f)3 and 4 of this subsection.

Response:

See LG&E's response to Filing Requirement 807 KAR 5:001 Section 16(7)(f) [Tab No. 19].

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

Response:

See LG&E's responses to Tab Nos. 22-38.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(1)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

1. *Operating income statement (exclusive of dividends per share or earnings per share);*

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2016.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Income Statements 2016 - 2019
Base Period: Twelve Months Ended February 28, 2017
Forecasted Test Period: Twelve Months Ended June 30, 2018

Louisville Gas and Electric Company - Total Company	**Income Statements**			
	2016	**2017**	**2018**	**2019**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Electric Operating Revenues	1,129,502,831	1,156,581,843	1,183,273,751	1,193,796,101
Gas Operating Revenues	294,412,814	327,771,422	331,315,068	335,404,413
Total Operating Revenues	1,423,915,645	1,484,353,265	1,514,588,820	1,529,200,514
Operating Expenses				
Fuel for Electric Generation	308,040,399	307,327,519	310,663,857	306,962,476
Power Purchased	54,419,496	58,259,411	56,831,642	49,900,484
Gas Supply Expenses	110,580,650	135,496,860	133,675,874	131,226,696
Other Operation Expenses	248,210,291	258,130,924	270,025,893	271,262,029
Maintenance	105,075,962.86	115,432,401	117,464,746	128,673,136
Depreciation & Amortization Expense	170,305,723	202,720,234	234,370,136	260,278,945
Regulatory Debits	168,077	822,673	1,392,415	2,009,171
Current Income Taxes	118,900,596	112,069,590	102,672,076	95,409,879
Property and Other Taxes	41,051,450	44,085,439	47,006,521	50,148,167
Investment Tax Credit	3,000,000	-	-	-
Amortization of Investment Tax Credit	(1,229,231)	(1,107,030)	(969,780)	(1,007,761)
Gains/Losses on Disp of Allowances	(72)	-	-	-
Total Operating Expenses	1,158,523,342	1,233,238,021	1,273,133,379	1,294,863,221
Net Operating Income	265,392,303	251,115,244	241,455,440	234,337,293
Other Income less deductions	(2,605,641)	(2,184,171)	(2,169,699)	(2,212,530)
Income before Interest Charges	262,786,662	248,931,073	239,285,741	232,124,763
Interest Charges	69,708,993	71,430,671	76,787,447	82,368,572
Net Income	193,077,669	177,500,402	162,498,294	149,756,192

Louisville Gas and Electric Company - Electric

	Income Statements			
	2016	**2017**	**2018**	**2019**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Electric Operating Revenues	1,129,502,831	1,156,581,843	1,183,273,751	1,193,796,101
Total Operating Revenues	1,129,502,831	1,156,581,843	1,183,273,751	1,193,796,101
Operating Expenses				
Fuel for Electric Generation	308,040,399	307,327,519	310,663,857	306,962,476
Power Purchased	54,419,496	58,259,411	56,831,642	49,900,484
Other Operation Expenses	193,169,030	198,867,737	208,255,818	210,331,899
Maintenance	87,427,393.26	97,222,648	97,894,552	108,358,842
Depreciation & Amortization Expense	135,851,379	165,000,731	193,805,317	214,679,558
Regulatory Debits	168,077	822,673	1,392,415	2,009,171
Current Income Taxes	97,758,140	91,110,573	82,863,161	75,536,032
Property and Other Taxes	30,810,459	33,148,919	35,338,321	37,974,910
Investment Tax Credit	3,000,000			
Amortization of Investment Tax Credit	(1,168,811)	(1,060,510)	(944,560)	(1,001,241)
Gains/Losses on Disp of Allowances	(72)			
Total Operating Expenses	909,475,490	950,699,702	986,100,521	1,004,752,129
Net Operating Income - Electric	220,027,341	205,882,142	197,173,230	189,043,972

Louisville Gas and Electric Company - Gas

	Income Statements			
	2016	**2017**	**2018**	**2019**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Gas Operating Revenues	294,412,814	327,771,422	331,315,068	335,404,413
Total Operating Revenues	294,412,814	327,771,422	331,315,068	335,404,413
Operating Expenses				
Gas Supply Expenses	110,580,650	135,496,860	133,675,874	131,226,696
Other Operation Expenses	55,041,261	59,263,187	61,770,075	60,930,130
Maintenance	17,648,570	18,209,753	19,570,194	20,314,294
Depreciation & Amortization	34,454,344	37,719,503	40,564,820	45,599,387
Regulatory Debits	-	-	-	-
Current Income Taxes	21,142,456	20,959,017	19,808,915	19,873,848
Property and Other Taxes	10,240,991	10,936,520	11,668,200	12,173,257
Amortization of Investment Tax Credit	(60,420)	(46,520)	(25,220)	(6,520)
Total Gas Operating Expenses	249,047,852	282,538,320	287,032,858	290,111,092
Net Operating Income - Gas	45,364,962	45,233,102	44,282,210	45,293,321

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(2)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

2. Balance sheet;

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2016.

Louisville Gas and Electric Company
Case No. 2016-00371
Balance Sheet - Total Company
Calendar Years 2016 - 2019

	2016	2017	2018	2019
Louisville Gas and Electric Company - Total	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	6,839,099,619	7,295,490,525	7,855,221,816	8,259,244,132
Accumulated Provision for Depreciation and Amortization	(2,060,004,442)	(2,187,768,934)	(2,358,814,840)	(2,498,642,594)
Total Utility Net Plant	**4,779,095,177**	**5,107,721,590**	**5,496,406,976**	**5,760,601,538**
INVESTMENTS				
Investment in Subsidiaries	594,286	594,286	594,286	594,286
Net nonutility property	567,535	567,535	567,535	567,535
Special funds	8,722,690	8,722,690	8,722,690	8,722,690
Total other Property and Investments	**9,884,511**	**9,884,511**	**9,884,511**	**9,884,511**
CURRENT AND ACCRUED ASSETS				
Cash	5,019,790	5,019,790	5,019,790	5,019,790
Special Deposits and Temporary Cash Investments	7	2	2	5
Accounts Receivable - Less Reserves	196,907,664	196,464,557	197,180,783	197,803,201
Accounts Receivable from Associated Companies	22,797,717	25,714,669	26,440,406	27,231,274
Inventories	145,329,412	118,508,351	116,900,817	116,436,626
Prepayments	14,798,127	15,057,414	15,460,671	16,045,587
Other current and accrued assets	-	-	-	-
Total Current and Accrued Assets	**384,852,717**	**360,764,783**	**361,002,468**	**362,536,483**
DEFERRED DEBITS & OTHER				
Unamortized Debt Expenses	31,413,360	32,057,917	30,105,845	29,094,487
Accumulated Deferred Income Tax Asset	284,296,675	284,296,675	284,296,675	284,296,675
Regulatory Assets	511,973,946	499,217,745	495,632,790	480,604,710
Miscellaneous deferred debits	7,580,538	6,664,295	7,949,061	3,518,765
Total Deferred Debits & Other	**835,264,519**	**822,236,633**	**817,984,371**	**797,514,638**
TOTAL ASSETS	**6,009,096,923**	**6,300,607,517**	**6,685,278,327**	**6,930,537,169**

Louisville Gas and Electric Company
Case No. 2016-00371
Balance Sheet - Total Company
Calendar Years 2016 - 2019

	2016	2017	2018	2019
Louisville Gas and Electric Company - Total	$	$	$	$
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	425,170,424	425,170,424	425,170,424	425,170,424
Common Stock Expense	(835,889)	(835,889)	(835,889)	(835,889)
Paid-in-capital	550,977,499	604,999,005	721,335,390	773,544,991
Retained Earnings	1,165,013,143	1,223,759,408	1,281,850,908	1,329,956,551
Other Comprehensive Income	-	-	-	-
Total Proprietary Capital	**2,140,325,178**	**2,253,092,948**	**2,427,520,834**	**2,527,836,077**
Total Long-term Debt	1,629,912,999	1,880,096,013	1,880,279,026	2,130,462,040
TOTAL CAPITALIZATION	**3,770,238,177**	**4,133,188,961**	**4,307,799,860**	**4,658,298,117**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	269,180,168	118,373,219	273,076,473	109,885,801
Accounts Payable	145,598,828	139,979,991	139,766,059	138,632,838
Accounts Payable to Associated Companies	21,378,219	25,361,948	29,283,957	34,794,806
Customer Deposits	26,279,737	26,279,737	26,279,737	26,279,737
Taxes Accrued	3,052,874	3,052,875	3,052,874	3,052,874
Interest Accrued	11,433,509	13,851,254	13,259,664	18,635,506
Dividends Payable Affiliate	0	(0)	0	(0)
Miscellaneous Current Liabilities	58,751,900	52,774,231	46,260,279	39,904,062
Total Current and Accrued Liabilities	**535,675,235**	**379,673,255**	**530,979,042**	**371,185,623**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	1,227,924,584	1,336,860,390	1,436,071,863	1,528,739,471
Investment Tax Credits	36,414,239	35,307,209	34,337,429	33,329,668
Regulatory Liabilities	81,393,539	75,933,533	73,521,312	71,166,744
Customer Advances for Construction	6,777,844	6,777,844	6,777,844	6,777,844
Asset Retirement Obligations	181,623,478	176,025,726	168,763,075	160,993,585
Other Deferred Credits	5,249,411	5,249,411	5,249,411	5,249,411
Miscellaneous Long Term Liabilities	4,249,578	4,249,578	4,249,578	4,249,578
Accumulated Provision for Post Retirement Benefits	159,550,837	147,341,610	117,528,911	90,547,127
Electric/Gas Balancing Adjustment	0	0	0	0
Total Deferred Credits	**1,703,183,510**	**1,787,745,302**	**1,846,499,424**	**1,901,053,429**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**6,009,096,923**	**6,300,607,517**	**6,685,278,327**	**6,930,537,169**

Louisville Gas and Electric Company

Case No. 2016-00371

Balance Sheet - Electric Utility

Calendar Years 2016 - 2019

	2016	2017	2018	2019
Louisville Gas and Electric Company - Electric Only	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	5,624,361,166	5,984,809,151	6,407,548,138	6,691,736,958
Accumulated Provision for Depreciation and Amortization	(1,711,910,381)	(1,813,872,783)	(1,954,199,691)	(2,072,654,512)
Total Utility Net Plant	**3,912,450,785**	**4,170,936,368**	**4,453,348,447**	**4,619,082,446**
INVESTMENTS				
Investment in Subsidiary Companies	594,286	594,286	594,286	594,286
Net Nonutility property	397,275	397,275	397,275	397,275
Special Funds	7,231,395	7,204,159	7,131,064	7,040,145
Total other Property and Investments	**8,222,955**	**8,195,719**	**8,122,624**	**8,031,706**
CURRENT AND ACCRUED ASSETS				
Cash	4,161,570	4,145,896	4,103,831	4,051,508
Special Deposits and Temporary Cash Investments	6	1	1	4
Accounts Receivable - Less Reserves	158,437,332	158,054,144	158,556,763	158,966,238
Accounts Receivable from Associated Companies	18,900,052	21,238,009	21,615,835	21,978,555
Inventories	102,673,855	74,980,208	74,927,059	75,112,555
Prepayments	12,535,494	12,755,136	13,096,734	13,592,217
Other Current and Accrued Assets	-	-	-	-
Total Current and Accrued Assets	**296,708,308**	**271,173,394**	**272,300,224**	**273,701,077**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	26,042,702	26,476,962	24,612,443	23,482,368
Accumulated Deferred Income Tax Asset	255,837,393	255,837,393	255,837,393	255,837,393
Regulatory Assets	447,498,831	437,630,488	435,008,549	420,413,245
Miscellaneous deferred debits	7,737,611	6,812,797	8,074,561	3,615,654
Total Deferred Debits & Other	**737,116,536**	**726,757,639**	**723,532,946**	**703,348,659**
TOTAL ASSETS	**4,954,498,585**	**5,177,063,121**	**5,457,304,241**	**5,604,163,888**

Louisville Gas and Electric Company
Case No. 2016-00371
Balance Sheet - Electric Utility
Calendar Years 2016 - 2019

	2016	2017	2018	2019
Louisville Gas and Electric Company - Electric Only	$	$	$	$
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	352,480,173	351,152,607	347,589,740	343,158,075
Common Stock Expense	(692,979)	(690,369)	(683,364)	(674,652)
Paid-in-capital	456,778,349	499,674,873	589,713,599	624,333,667
Retained Earnings	965,833,960	1,010,715,426	1,047,952,066	1,073,417,397
Other Comprehensive Income	-	-	-	-
Total Proprietary Capital	**1,774,399,503**	**1,860,852,537**	**1,984,572,041**	**2,040,234,488**
Total Long-term Debt	1,351,251,131	1,552,790,549	1,537,185,235	1,719,511,074
TOTAL CAPITALIZATION	**3,125,650,634**	**3,413,643,087**	**3,521,757,276**	**3,759,745,562**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	223,159,154	97,765,654	223,248,314	88,689,612
Accounts Payable	126,016,218	120,960,796	119,845,055	117,550,055
Accounts Payable to Associated Companies	17,723,242	20,946,692	23,940,524	28,083,135
Customer Deposits	21,786,760	21,704,704	21,484,483	21,210,563
Taxes Accrued	2,530,933	2,521,400	2,495,818	2,463,997
Interest Accrued	9,478,753	11,439,892	10,840,178	15,040,849
Dividends Payable Affiliate	-	-	-	-
Miscellaneous Current Liabilities	48,707,245	43,586,778	37,819,184	32,206,852
Total Current and Accrued Liabilities	**449,402,305**	**318,925,917**	**439,673,555**	**305,245,063**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	989,160,698	1,078,459,363	1,157,853,464	1,233,141,664
Investment Tax Credits	36,332,333	35,271,823	34,327,263	33,326,022
Regulatory Liabilities	72,045,019	66,974,300	64,654,985	62,321,836
Customer Advances for Construction	6,724,404	6,724,404	6,724,404	6,724,404
Asset Retirement Obligations	142,926,671	138,761,310	133,357,076	127,575,697
Other Deferred Credits	4,351,934	4,335,543	4,291,553	4,236,837
Miscellaneous Long Term Liabilities	3,523,039	3,509,770	3,474,159	3,429,864
Accumulated Provision for Post Retirement Benefits	132,272,857	121,690,945	96,083,456	73,081,231
Electric/Gas Balancing Adjustment	(7,891,309)	(11,233,340)	(4,892,951)	(4,664,293)
Total Deferred Credits	**1,379,445,646**	**1,444,494,117**	**1,495,873,409**	**1,539,173,263**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**4,954,498,585**	**5,177,063,121**	**5,457,304,241**	**5,604,163,888**

Louisville Gas and Electric Company
Case No. 2016-00371
Balance Sheet - Gas Utility
Calendar Years 2016 - 2019

	2016	2017	2018	2019
Louisville Gas and Electric Company - Gas Only	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	1,214,738,453	1,310,681,374	1,447,673,679	1,567,507,174
Accumulated Provision for Depreciation and Amortization	(348,094,062)	(373,896,152)	(404,615,149)	(425,988,082)
Total Utility Net Plant	**866,644,391**	**936,785,222**	**1,043,058,530**	**1,141,519,091**
INVESTMENTS				
Investment in Subsidiary Companies	-	-	-	-
Net Nonutility property	170,261	170,261	170,261	170,261
Special Funds	1,491,295	1,518,531	1,591,626	1,682,545
Total other Property and Investments	**1,661,555**	**1,688,791**	**1,761,886**	**1,852,805**
CURRENT AND ACCRUED ASSETS				
Cash	858,220	873,894	915,959	968,282
Special Deposits and Temporary Cash Investments	1	1	1	1
Accounts Receivable - Less Reserves	38,470,332	38,410,413	38,624,020	38,836,963
Accounts Receivable from Associated Companies	3,897,665	4,476,661	4,824,571	5,252,719
Inventories	42,655,557	43,528,143	41,973,758	41,324,071
Prepayments	2,262,634	2,302,279	2,363,937	2,453,370
Other Current and Accrued Assets	-	-	-	-
Total Current and Accrued Assets	**88,144,408**	**89,591,390**	**88,702,245**	**88,835,405**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	5,370,658	5,580,955	5,493,402	5,612,120
Accumulated Deferred Income Tax Asset	28,459,283	28,459,283	28,459,283	28,459,283
Regulatory Assets	64,475,115	61,587,257	60,624,240	60,191,464
Miscellaneous deferred debits	(157,073)	(148,502)	(125,500)	(96,889)
Total Deferred Debits & Other	**98,147,983**	**95,478,993**	**94,451,425**	**94,165,978**
TOTAL ASSETS	**1,054,598,338**	**1,123,544,397**	**1,227,974,086**	**1,326,373,280**

Louisville Gas and Electric Company
Case No. 2016-00371
Balance Sheet - Gas Utility
Calendar Years 2016 - 2019

(000s)	2016	2017	2018	2019
Louisville Gas and Electric Company - Gas Only	$	$	$	$
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	72,690,251	74,017,817	77,580,684	82,012,349
Common Stock Expense	(142,910)	(145,520)	(152,524)	(161,237)
Paid-in-capital	94,199,150	105,324,132	131,621,791	149,211,324
Retained Earnings	199,179,183	213,043,982	233,898,842	256,539,154
Other Comprehensive Income	-	-	-	-
Total Proprietary Capital	**365,925,675**	**392,240,410**	**442,948,793**	**487,601,589**
Total Long-term Debt	278,661,869	327,305,464	343,093,791	410,950,966
TOTAL CAPITALIZATION	**644,587,543**	**719,545,874**	**786,042,584**	**898,552,555**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	46,021,014	20,607,565	49,828,159	21,196,189
Accounts Payable	19,582,610	19,019,195	19,921,004	21,082,782
Accounts Payable to Associated Companies	3,654,977	4,415,255	5,343,432	6,711,670
Customer Deposits	4,492,976	4,575,033	4,795,253	5,069,174
Taxes Accrued	521,942	531,474	557,057	588,878
Interest Accrued	1,954,756	2,411,361	2,419,486	3,594,656
Dividends Payable Affiliate	-	-	-	-
Miscellaneous Current Liabilities	10,044,655	9,187,453	8,441,095	7,697,209
Total Current and Accrued Liabilities	**86,272,931**	**60,747,338**	**91,305,487**	**65,940,560**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	238,763,878	258,401,027	278,218,401	295,597,809
Investment Tax Credits	81,906	35,386	10,166	3,646
Regulatory Liabilities	9,348,519	8,959,233	8,866,327	8,844,908
Customer Advances for Construction	53,441	53,441	53,441	53,441
Asset Retirement Obligations	38,696,807	37,264,416	35,405,999	33,417,888
Other Deferred Credits	897,478	913,869	957,858	1,012,574
Miscellaneous Long Term Liabilities	726,539	739,808	775,419	819,713
Accumulated Provision for Post Retirement Benefits	27,277,980	25,650,666	21,445,455	17,465,896
Electric/Gas Balancing Adjustment	7,891,316	11,233,339	4,892,950	4,664,289
Total Deferred Credits	**323,737,864**	**343,251,184**	**350,626,015**	**361,880,165**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**1,054,598,338**	**1,123,544,396**	**1,227,974,086**	**1,326,373,280**

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(3)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

3. Statement of cash flows;

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2016.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Cash Flow Statements 2016 - 2019
Base Period: Twelve Months Ended February 28, 2017
Forecasted Test Period: Twelve Months Ended June 30, 2018

Louisville Gas and Electric Company Cash Flow Statements	**2016**	**2017**	**2018**	**2019**
Cash Flows from Operating Activities				
Net Income	$ 193,077,669	$ 177,500,402	$ 162,498,294	$ 149,756,192
Items not requiring (providing) cash currently:				
Depreciation	170,324,487	202,720,234	234,370,136	260,278,945
Amortization	10,165,517	14,501,193	13,339,372	14,412,743
Deferred Income Taxes and Investment Tax Credits	116,718,214	106,854,582	97,436,706	90,912,512
Change in current assets and current liabilities:				
Change in Customer A/R	(36,775,113)	(2,473,845)	(1,441,963)	(1,413,285)
Change in Inventories	7,510,061	26,877,063	1,607,534	464,191
Change in Other Current Assets	(7,108,545)	466,480	(1,878,498)	3,654,904
Change in Regulatory Assets	5,864,611	(4,019,233)	(1,390,888)	(72,914)
Change in Accounts Payable	21,925,573	(3,790,722)	1,955,890	2,949,926
Change in Taxes Accrued	(16,938,268)	-	-	-
Change in Interest Accrued	567,556	2,417,745	(591,590)	5,375,842
Change in Price Risk Management	(13,068,248)			
Change in Other Current Liabilities	(1,723,179)	13,624,021	13,768,238	11,820,881
Other operating activities:				
ARO Expenditures	(20,610,618)	(12,821,330)	(13,901,710)	(14,150,760)
Pension Cash Payments	(47,326,329)	(7,096,253)	(23,881,655)	(19,952,476)
Other	3,918,903	-	-	-
Net Cash from Operating Activities	386,522,292	514,760,335	481,889,868	504,036,700
Cash Flows from Investing Activities				
Capital Expenditures for Property, Plant and Equipment	(508,714,244)	(546,848,253)	(648,522,713)	(539,032,576)
Net Cash from Investing Activities	(508,714,244)	(546,848,253)	(648,522,713)	(539,032,576)
Cash Flows from Financing Activities				
Issuance of Long-Term Debt	-	250,000,000	-	250,000,000.00
Net (Decrease) Increase in Short-Term Debt	127,195,962	(150,806,950)	154,703,253	(163,190,675)
Capital Contribution Received from Parent	133,896,000	54,021,506	116,336,385	52,209,600
Dividends on common stock	(126,918,989)	(118,754,138)	(104,406,793)	(101,650,549)
Retirement of Long-Term Debt	(25,000,000)	-	-	-
Cost of Issuing or Retiring Debt	(742,326)	(2,372,500)	-	(2,372,500)
Net Cash from Financing Activities	108,430,647	32,087,918	166,632,846	34,995,876
Net (Decrease) Increase in Cash and Cash Equivalents	(13,761,306)	-	-	-
Cash & Cash Equivalents - Beginning of Period	18,781,096	5,019,790	5,019,790	5,019,790
Cash & Cash Equivalents - End of Period	$ 5,019,790	$ 5,019,790	$ 5,019,790	$ 5,019,790

Note - The cash flow statements presented are at the Company level and not at a jurisdictional level.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(4)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

4. Revenue requirements necessary to support the forecasted rate of return;

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2016-00371
ELECTRIC - OVERALL FINANCIAL SUMMARY
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31,

		FORECASTED			
		2016	2017	2018	2019
LINE NO.	DESCRIPTION	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT
		$	$	$	$
1	CAPITALIZATION ALLOCATED TO ELECTRIC OPERATIONS (a)	2,205,763,158	2,339,676,393	2,461,569,451	2,620,120,234
2	ADJUSTED OPERATING INCOME	151,347,539	131,333,757	114,874,988	104,454,275
3	EARNED RATE OF RETURN (2 / 1)	6.86%	5.61%	4.67%	3.99%
4	REQUIRED RATE OF RETURN	7.30%	7.23%	7.21%	7.24%
5	REQUIRED OPERATING INCOME (1 x 4)	160,914,420	169,148,119	177,458,915	189,578,735
6	OPERATING INCOME DEFICIENCY (5 - 2)	9,566,881	37,814,362	62,583,927	85,124,460
7	GROSS REVENUE CONVERSION FACTOR	1.640935	1.640935	1.640935	1.640935
8	REVENUE DEFICIENCY (6 x 7) (b)	15,698,628	62,050,903	102,696,144	139,683,688
9	ADJUSTED OPERATING REVENUES	999,118,674	1,014,360,293	1,018,137,606	1,014,194,359
10	REVENUE REQUIREMENTS (8 + 9)	1,014,817,302	1,076,411,196	1,120,833,749	1,153,878,047

(a) 13 months average
(b) Held constant for all periods. See Section 16(8)(h) Schedule H-1

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

GAS - OVERALL FINANCIAL SUMMARY

FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31,

		FORECASTED			
		2016	2017	2018	2019
LINE NO.	DESCRIPTION	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT
		$	$	$	$
1	CAPITALIZATION ALLOCATED TO GAS OPERATIONS (a)	492,696,264	592,781,175	730,664,409	770,829,945
2	ADJUSTED OPERATING INCOME	35,170,147	37,590,884	40,725,465	38,977,868
3	EARNED RATE OF RETURN (2 / 1)	7.14%	6.34%	5.57%	5.06%
4	REQUIRED RATE OF RETURN	7.30%	7.23%	7.21%	7.24%
5	REQUIRED OPERATING INCOME (1 x 4)	35,943,085	42,855,423	52,674,895	55,773,382
6	OPERATING INCOME DEFICIENCY (5 - 2)	772,939	5,264,538	11,949,430	16,795,514
7	GROSS REVENUE CONVERSION FACTOR	1.640935	1.640935	1.640935	1.640935
8	REVENUE DEFICIENCY (6 x 7)	1,268,342	8,638,764	19,608,235	27,560,343
9	ADJUSTED OPERATING REVENUES	154,769,233	168,662,155	183,372,531	182,661,145
10	REVENUE REQUIREMENTS (8 + 9)	156,037,575	177,300,919	202,980,767	210,221,488

(a) 13 months average

(b) Held constant for all periods. See Section 16(8)(h) Schedule H-1

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

5. Load forecast including energy and demand (electric);

Response:

LG&E Energy (GWh)

Rate	2016 *	2017	2018	2019
PS-Pri	156	165	166	167
PS-Sec	1,880	1,883	1,866	1,852
TOD-Pri	1,822	1,844	1,854	1,873
TOD-Sec	1,071	1,074	1,076	1,077
Special Contract 1	122	110	110	110
GS	1,311	1,359	1,357	1,356
Special Contract 2	56	58	58	58
RS	4,060	4,179	4,181	4,191
RTS	1,100	1,147	1,147	1,147
Lighting	107	108	108	108
Total	11,684	11,929	11,922	11,941

*2016 includes 8 months of actual data and 4 months forecast

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(5)
Sponsoring Witness: David S. Sinclair

LG&E Demand (Sum of Monthly Billing Demands)

Rate	SubRate	Unit	2016 *	2017	2018	2019
PS-Pri	Base	MW	407	398	400	405
PS-Sec	Base	MW	5,072	4,986	4,939	4,903
TOD-Pri	Base	MVA	4,371	4,349	4,373	4,418
	Intermediate	MVA	4,146	4,134	4,156	4,199
	Peak	MVA	4,063	4,069	4,091	4,133
TOD-Sec	Base	MW	2,642	2,590	2,594	2,597
	Intermediate	MW	2,380	2,344	2,347	2,350
	Peak	MW	2,320	2,288	2,291	2,294
Special Contract 1	Base	MW	197	185	185	185
Special Contract 2	Base	MW	113	114	114	114
RTS	Base	MVA	2,341	2,424	2,424	2,424
	Intermediate	MVA	2,212	2,289	2,289	2,289
	Peak	MVA	2,146	2,201	2,201	2,201

*2016 includes 8 months of actual data and 4 months forecast

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(6)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

6. Access line forecast (telephone);

Response:

Not applicable to LG&E's Application**.**

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(7)
Sponsoring Witness: David S. Sinclair

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

7. Mix of generation (electric);

Response:

See attached.

GWh[1]	**2016**[2]	**2017**	**2018**	**2019**
Coal				
Brown 1	N/A	N/A	N/A	N/A
Brown 2	N/A	N/A	N/A	N/A
Brown 3	N/A	N/A	N/A	N/A
Ghent 1	N/A	N/A	N/A	N/A
Ghent 2	N/A	N/A	N/A	N/A
Ghent 3	N/A	N/A	N/A	N/A
Ghent 4	N/A	N/A	N/A	N/A
Mill Creek 1	1,766	1,737	1,894	1,644
Mill Creek 2	1,619	1,716	1,563	1,857
Mill Creek 3	1,877	2,175	2,439	2,054
Mill Creek 4	2,643	3,157	2,721	3,195
OVEC	571	493	463	465
Trimble County 1	2,642	2,028	2,505	2,302
Trimble County 2	545	676	642	705
SCCT				
Bluegrass/EKPC[3]	34	45	52	14
Brown 5	35	14	25	11
Brown 6	11	21	24	21
Brown 7	9	26	35	30
Brown 8	N/A	N/A	N/A	N/A
Brown 9	N/A	N/A	N/A	N/A
Brown 10	N/A	N/A	N/A	N/A
Brown 11	N/A	N/A	N/A	N/A
Cane Run 11	0	0	0	0
Haefling	N/A	N/A	N/A	N/A
Paddys Run 11	0	0	0	0
Paddys Run 12	0	0	0	0
Paddys Run 13	61	103	99	87
Trimble Co 05	88	92	119	90
Trimble Co 06	58	89	99	78
Trimble Co 07	97	84	85	83
Trimble Co 08	24	22	31	22
Trimble Co 09	72	61	78	52
Trimble Co 10	31	13	17	13
Zorn 1	0	0	0	0
NGCC				
Cane Run 7	1,087	1,077	1,087	984
Hydro				
Dix Dam	N/A	N/A	N/A	N/A
Ohio Falls	295	263	287	287
Solar				
Brown Solar	5	8	8	8
Total Coal	11,663	11,982	12,226	12,222
Total SCCT	522	572	666	500
Total NGCC	1,087	1,077	1,087	984
Total Hydro	295	263	287	287
Total Solar	5	8	8	8
Grand Total	13,571	13,902	14,274	14,001

[1] Generation volumes reflect LG&E's ownership share of the unit. "N/A" is shown for units with no LG&E ownership share.
[2] 2016 generation volumes reflect actual generation for January-August and forecast generation for September-December.
[3] Capacity Purchase and Tolling Agreement with Bluegrass Generation/EKPC

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(8)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

8. Mix of gas supply (gas);

Response:

LOUISVILLE GAS AND ELECTRIC COMPANY				
MIX OF GAS SUPPLY				
CALENDAR YEARS 2016, 2017, 2018, 2019				
MMcf	**2016 ***	**2017**	**2018**	**2019**
Total Pipeline Purchases	29,991	33,271	33,044	32,837

*2016: 8 months actual, 4 months forecast

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(9)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

9. Employee level;

Response:

See attached.

Louisville Gas and Electric Company
Case No. 2016-00371
Employee Level
Years 2016-2019

	Estimated Number of Full-Time LG&E Employees at 12/31
2016	1033
2017	1033
2018	1053
2019	1045

	Estimated Number of Total LG&E Employees at 12/31 [A]
2016	1063
2017	1057
2018	1077
2019	1069

	Estimated Number of Full-Time LG&E and KU Services Company (LKS) Employees at 12/31*
2016	1603
2017	1622
2018	1614
2019	1611

	Estimated Number of Total LG&E and KU Services Company (LKS) Employees at 12/31* [A]
2016	1670
2017	1687
2018	1678
2019	1673

*LGE and KU Services employees serve LGE, KU, and LGE & KU Energy LLC. Number of LGE and KU Services employees is not allocated; however, labor dollars are allocated via the Cost Allocation Manual (CAM).

[A] Totals include part-time employees, cooperatives and interns.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(10)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

10. Labor cost changes;

Response:

See attached.

Louisville Gas and Electric Company
Case No. 2016-00371
Labor Cost
Years 2016-2019

Forecast Year	Total Wages	Amount Over Previous Year	Percentage Over Previous Year
2016	$ 160,609,231		
2017	$ 164,057,067	$ 3,447,836	2.15%
2018	$ 167,590,458	$ 3,533,391	2.15%
2019	$ 171,600,831	$ 4,010,374	2.39%

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(11)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

11. Capital structure requirements;

Response:

See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2016-00371
ELECTRIC - CAPITAL STRUCTURE REQUIREMENT
AS OF
DECEMBER 31

		FORECASTED							
		2016		2017		2018		2019	
LINE NO.	CLASS OF CAPITAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		$		$		$		$	
	ELECTRIC:								
1	DEBT	158,517,913	6.72%	68,366,805	2.81%	155,639,179	6.00%	62,793,664	2.32%
2	DEBT	941,342,854	39.88%	1,067,339,895	43.80%	1,054,501,079	40.66%	1,200,815,446	44.34%
3	EQUITY	1,260,419,309	53.40%	1,301,280,528	53.40%	1,383,558,774	53.34%	1,444,518,644	53.34%
4	TOTAL CAPITAL	2,360,280,076	100.00%	2,436,987,228	100.00%	2,593,699,031	100.00%	2,708,127,754	100.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2016-00371
GAS - CAPITAL STRUCTURE REQUIREMENT
AS OF
DECEMBER 31

		FORECASTED							
		2016		2017		2018		2019	
LINE NO.	CLASS OF CAPITAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		$		$		$		$	
	GAS:								
1	DEBT	34,009,329	6.72%	20,469,313	2.81%	46,975,138	6.00%	18,782,494	2.32%
2	DEBT	201,961,015	39.88%	319,566,112	43.80%	318,270,334	40.66%	359,181,284	44.34%
3	EQUITY	270,417,481	53.40%	389,608,934	53.40%	417,586,782	53.34%	432,076,438	53.34%
4	TOTAL CAPITAL	506,387,825	100.00%	729,644,359	100.00%	782,832,254	100.00%	810,040,216	100.00%

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(12)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

12. Rate base;

Response:

See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Electric - Net Original Cost Rate Base as of December 31,

Title of Account (1)	Forecasted 2016 (2)	2017 (3)	2018 (3)	2019 (4)
1. Utility Plant at Original Cost	$ 4,244,042,287	$ 4,465,165,852	$ 4,699,114,562	$ 4,916,694,633
2. Deduct:				
3. Reserve for Depreciation	1,644,159,515	1,694,340,148	1,769,637,468	1,815,271,379
4. Net Utility Plant	2,599,882,773	2,770,825,704	2,929,477,094	3,101,423,255
5. Deduct:				
6. Customer Advances for Construction	7,037,690	6,724,404	6,724,404	6,724,404
7. Accumulated Deferred Income Taxes	496,244,179	556,423,841	564,612,200	608,919,819
8. Total Deductions	503,281,869	563,148,245	571,336,604	615,644,223
9. Net Plant Deductions	2,096,600,903	2,207,677,459	2,358,140,490	2,485,779,032
10. Add:				
11. Material and Supplies	99,112,165	82,762,454	69,821,131	69,210,566
12. Gas Stored Underground	-	0	0	0
13. Prepayments	10,362,187	13,288,993	13,958,540	14,367,993
14. Cash Working Capital (page 2)	72,379,766	74,307,377	75,711,244	76,699,374
15. Total Additions	181,854,118	170,358,824	159,490,915	160,277,933
16. Total Net Original Cost Rate Base	$ 2,278,455,021	$ 2,378,036,283	$ 2,517,631,405	$ 2,646,056,965

LOUISVILLE GAS AND ELECTRIC COMPANY

Electric - Calculation of Cash Working Capital
As of December 31,

Title of Account (1)	Forecasted 2016 (2)	2017 (3)	2018 (3)	2019 (4)
1. Operating and maintenance expense for the 12 months ended December 31	$ 633,457,620	$ 652,718,428	$ 662,521,598	$ 663,495,476
2. Deduct:				
3. Electric Power Purchased	54,419,496	58,259,411	56,831,642	49,900,484
4. Gas Supply Expenses				
5. Total Deductions	$ 54,419,496	$ 58,259,411	$ 56,831,642	$ 49,900,484
6. Remainder (Line 1 - Line 5)	$ 579,038,124	$ 594,459,018	$ 605,689,956	$ 613,594,992
7. Cash Working Capital (12 1/2% of Line 6)	$ 72,379,765	$ 74,307,377	$ 75,711,244	$ 76,699,374

LOUISVILLE GAS AND ELECTRIC COMPANY
Case No. 2016-00371
Gas - Net Original Cost Rate Base as of December 31

Title of Account (1)	2016 (2)	Forecasted 2017 (3)	2018 (4)	2019 (5)
1. Utility Plant at Original Cost	$ 972,718,806	$ 1,266,504,265	$ 1,356,588,331	$ 1,414,617,845
2. Deduct:				
3. Reserve for Depreciation	333,656,699	371,308,527	401,592,351	421,640,353
4. Net Utility Plant	639,062,107	895,195,738	954,995,979	992,977,491
5. Deduct:				
6. Customer Advances for Construction	(53,093)	53,441	53,441	53,441
7. Accumulated Deferred Income Taxes	177,069,107	223,596,869	235,969,210	245,563,534
8. Total Deductions	177,016,014	223,650,309	236,022,651	245,616,974
9. Net Plant Deductions	462,046,093	671,545,428	718,973,329	747,360,517
10. Add:				
11. Material and Supplies	288,095	326,073	321,293	316,667
12. Gas Stored Underground	29,218,463	27,310,839	26,742,973	25,927,060
13. Prepayments	1,805,454	2,398,639	2,519,491	2,593,396
14. Cash Working Capital (page 2)	9,086,229	9,684,117	10,167,534	10,155,553
15. Total Additions	40,398,241	39,719,668	39,751,292	38,992,676
16. Total Net Original Cost Rate Base	$ 502,444,334	$ 711,265,096	$ 758,724,620	$ 786,353,193

LOUISVILLE GAS AND ELECTRIC COMPANY

Gas - Calculation of Cash Working Capital
As of December 31

	Forecasted			
Title of Account (1)	2,016 (2)	2,017 (3)	2,018 (4)	2,019 (5)
1. Operating and maintenance expense for the 12 months ended December 31	$ 183,270,481	$ 212,969,800	$ 215,016,144	$ 212,471,121
2. Deduct:				
3. Electric Power Purchased				
4. Gas Supply Expenses	110,580,650	135,496,860	133,675,874	131,226,696
5. Total Deductions	$ 110,580,650	$ 135,496,860	$ 133,675,874	$ 131,226,696
6. Remainder (Line 1 - Line 5)	$ 72,689,830	$ 77,472,940	$ 81,340,270	$ 81,244,424
7. Cash Working Capital (12 1/2% of Line 6)	$ 9,086,229	$ 9,684,117	$ 10,167,534	$ 10,155,553

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(13)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

13. Gallons of water projected to be sold (water);

Response:

Not applicable to LG&E's Application.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(14)
Sponsoring Witness: David S. Sinclair

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

14. Customer forecast (gas, water);

Response:

LG&E Natural Gas Average Number of Customers

Rate	2016 *	2017	2018	2019
As-Available Gas Service, Commercial	2	2	2	2
As-Available Gas Service, Industrial	2	2	2	2
Firm Commercial Gas Service	25,094	24,980	24,918	24,870
Firm Industrial Gas Service	249	259	265	271
Gas Special Contracts - LG&E	1	1	1	1
Gas Transport Service, FT Commercial	10	10	10	10
Gas Transport Service, FT Industrial	67	63	63	63
Gas Transport Service, Paddy's Run	1	-	-	-
Residential Gas Service	295,731	296,120	296,652	297,256
TS-2: Gas Trans/Firm Balancing (AAGS In)	2	2	2	2
TS-2: Gas Transport/Firm Balancing (IGS)	6	5	5	5
Grand Total	321,164	321,444	321,920	322,482

*2016 includes 8 months of actual data and 4 months forecast

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(15)
Sponsoring Witness: David S. Sinclair

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

15. Sales volume forecasts – cubic feet (gas);

Response:

LG&E Natural Gas Volumes Forecast (Mcf)

Rate	2016 *	2017	2018	2019
As-Available Gas Service, Commercial	58,669	57,313	57,577	57,577
As-Available Gas Service, Industrial	72,985	70,797	70,797	70,797
Firm Commercial Gas Service	10,056,342	10,166,752	10,108,470	10,010,001
Firm Industrial Gas Service	1,318,327	1,465,706	1,514,612	1,570,906
Gas Special Contracts - LG&E	263,503	158,488	153,590	147,222
Gas Transport Service, FT Commercial	721,324	687,286	687,286	687,286
Gas Transport Service, FT Industrial	12,143,217	11,594,715	11,643,270	11,705,426
Gas Transport Service, Paddy's Run	845,171	-	-	-
Residential Gas Service	19,334,212	19,650,188	19,438,040	19,279,491
TS-2: Gas Trans/Firm Balancing (AAGS In)	273,524	255,327	255,327	255,327
TS-2: Gas Transport/Firm Balancing (IGS)	495,272	459,452	459,452	459,452
Grand Total	45,582,547	44,566,024	44,388,420	44,243,483

*2016 includes 8 months of actual data and 4 months forecast

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(16)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

16. Toll and access forecast of number of calls and number of minutes (telephone); and

Response:

Not applicable to LG&E's Application.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(17)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

17. A detailed explanation of other information provided, if applicable.

Response:

Not applicable to LG&E's Application.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(i)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communications Commission audit reports.

Response:

The most recent Federal Energy Regulatory Commission ("FERC") audit report relating to LG&E is attached. The Federal Communications Commission has not conducted an audit of LG&E, and, therefore, no such audit reports exist.

In Reply Refer To:
Office of Enforcement
Docket No. FA12-12-000
October 9, 2014

PPL Corporation
Attention: Robert J. Grey
Executive Vice President, General Counsel and Secretary
Two North Ninth St.
Allentown, PA 18101

Dear Mr. Grey:

1. The Division of Audits and Accounting within the Office of Enforcement (OE) has completed an audit of PPL Corporation (PPL), including its service companies and associated companies. The purpose of the audit was to evaluate the companies' compliance with Federal Energy Regulatory Commission (Commission): (1) cross-subsidization restrictions on affiliate transactions under 18 C.F.R. pt. 35; (2) accounting, recordkeeping, and reporting requirements under 18 C.F.R. pt. 366; (3) Uniform System of Accounts (USofA) for centralized service companies under 18 C.F.R. pt. 367; (4) preservation of records requirements for holding and service companies under 18 C.F.R. pt. 368; and (5) FERC Form No. 60 annual report requirements under 18 C.F.R. pt. 369.

The audit evaluated PPL's associated public utilities' compliance with Commission accounting requirements for transactions with associated companies under 18 C.F.R. pt. 101 and the applicable reporting requirements in the FERC Form No. 1. The audit also evaluated compliance with the conditions upon which the Commission granted merger and acquisition of jurisdictional facilities authorization in Docket No. EC10-77-000.

Moreover, the audit evaluated Kentucky Utilities Company (KU) and Louisville Gas and Electric Company's (LG&E) compliance with their transmission cost-of-service formula rate schedule included as Attachment O of KU and LG&E's Open Access Transmission Tariff (OATT) and PPL Electric Utilities Corporation's compliance with its transmission cost of service formula rate schedule included as Attachment H-8-G of PJM Interconnection, L.L.C.'s OATT. The audit covered the period from January 1, 2010 through December 31, 2011. The enclosed audit report explains our audit findings and recommendations.

2. On September 26, 2014, PPL agreed with the findings and accepted the recommendations contained in the audit report. PPL stated it has already undertaken some corrective actions, as observed in the audit report.

3. In addition, PPL also provided descriptions of the planned corrective actions it will take to comply with the audit report recommendations and provided target completion dates. The appendix to the audit report includes a copy of PPL's response. I hereby approve the audit report.

4. PPL should submit its implementation plan within 30 days of this letter and make quarterly submissions to DAA describing the progress made to comply with the recommendations. As indicated in the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all corrective actions are completed.

5. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. section 375.311 (2013). This letter order constitutes final agency action. PPL may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. section 385.713 (2013).

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of non-compliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8741.

Sincerely,

Larry D. Gasteiger
Acting Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission

Audit of

PPL Corporation's Affiliate Transactions, and Compliance with:

- Cross-subsidization Restrictions on Affiliated Transactions;

- Regulations under the Public Utility Holding Company Act of 2005;

- Uniform System of Accounts for Public Utilities and Accounting for Service Company Billings;

- Merger Conditions under Docket No. EC10-77-000; and

- Transmission Formula Rates

Docket No. FA12-12-000
October 9, 2014

Office of Enforcement
Division of Audits and Accounting

TABLE OF CONTENTS

I. Executive Summary

A. Overview

The Division of Audits and Accounting (DAA) within the Office of Enforcement has completed an audit of PPL Corporation (PPL), including its service and associated companies. The audit was commenced to evaluate compliance with the Federal Energy Regulatory Commission's (FERC or the Commission): (1) cross-subsidization restrictions on affiliate transactions;[1] (2) accounting, recordkeeping, and reporting requirements;[2] (3) Uniform System of Accounts (USofA) for centralized service companies;[3] (4) preservation of records requirements for holding and service companies;[4] and (5) FERC Form No. 60 annual report requirements.[5]

The audit evaluated PPL's associated public utilities' compliance with Commission accounting requirements for transactions with associated companies under 18 C.F.R. pt. 101 and applicable reporting requirements in the FERC Form No. 1. The audit also evaluated compliance with the conditions upon which the Commission granted merger and acquisition of jurisdictional facilities authorization in Docket No. EC10-77-000. Lastly, the audit evaluated Kentucky Utilities Company (KU) and Louisville Gas and Electric Company's (LG&E) compliance with their transmission cost-of-service formula rate schedule included as Attachment O of KU and LG&E's Open Access Transmission Tariff (OATT) and PPL Electric Utilities Corporation's (PPL Electric) compliance with its transmission cost-of-service formula rate schedule included as Attachment H-8-G of PJM Interconnection, L.L.C.'s (PJM) OATT. The audit covered the period from January 1, 2010 through December 31, 2011.

Based on audit staff examination of KU, LG&E, and PPL Electric's accounting and formula rate calculations, audit staff identified numerous areas of substantial non-compliance with various Commission requirements. The level of non-compliance and the seriousness of these matters uncovered during the audit resulted in excessive formula rate billings to wholesale transmission customers. Audit staff is very concerned that the lack of sufficient oversight of PPL's accounting and formula rate policies that impact rate recovery have contributed to erroneous and excessive formula rate billings to wholesale

[1] 18 C.F.R. pt. 35.

[2] *Id.* pt. 366.

[3] *Id.* pt. 367.

[4] *Id.* pt. 368.

[5] *Id.* pt. 369.

transmission customers. Audit staff is also concerned that wholesale transmission customers would have continued to pay excessive amounts through formula rate billings had these areas of non-compliance gone undetected by audit staff. However, audit staff is encouraged by PPL's: (1) cooperation throughout the entire audit process and (2) swift and comprehensive implementation plan to correct these serious breaches of compliance with Commission requirements during and after the audit fieldwork. These areas of non-compliance are reflected in the compliance findings summarized in section C below and in full in section IV.

B. Transmission Formula Rate

KU and LG&E

KU and LG&E operate their system as a single, integrated, and coordinated transmission system and provide transmission service under the terms of their shared joint OATT. KU and LG&E adopted a formula rate for transmission service under schedule 7 (covering long-term firm and short-term firm point-to-point transmission service), schedule 8 (covering non-firm point-to-point transmission service), and schedule 9 (covering network integration service). The formula rate also provides for recovery of their Independent Transmission Organization and Reliability Coordinator costs.

The formula rate is in Attachment O to KU and LG&E's OATT. KU and LG&E are not required to file an annual informational or compliance filing for their wholesale transmission cost-of-service formula rate. Rather, KU and LG&E post the formula rate on OASIS by May 1, effective June 1, each year. All amounts in the formula rate are based on actual amounts. There are no over/under-collections, refunds, additional billings, projections, or estimates in the formula rate.

The transmission formula rate calculation is prepared in an Excel spreadsheet that primarily uses FERC Form No. 1 data. Each input item is identified within the spreadsheet, KU and LG&E's FERC Form No. 1 data are entered in the input section of the spreadsheet, and they are combined to calculate the final combined OATT rates. Sources of the data used to prepare the transmission formula rate are the KU and LG&E FERC Form No. 1s for the calendar year. Specific pages and line numbers are in the data entry section of the formula spreadsheet to help identify correct data points. After initial data entry is completed, separate teams in the accounting and transmission groups review the formula inputs and results to ensure data accuracy. The Rates and Regulatory (Rates) group maintains the spreadsheet where the formula rate is calculated. The Rates group enters data from the FERC Form No. 1, which allows formula rates to be calculated in the spreadsheet.

PPL Electric

PPL Electric is a member of PJM. PJM directs the operation of PPL Electric's transmission facilities, and transmission service over these facilities is provided under the PJM OATT. PPL Electric's annual transmission revenue requirement (ATRR) and annual transmission rates are set forth in Attachment H-8G to PJM's OATT, and the formula rate implementation protocols (Protocols) for the ATRR and rates are set forth in Attachment H-8H to PJM's OATT. The Protocols describe the process in which PPL Electric will account for certain inputs, updates to the formula, annual review procedures, and formal challenge procedures.

PPL Electric's ATRR established point-to-point transmission rates to the PPL Group Zone and Network Integration Transmission Service (NITS) rates in the PPL Group Zone. PPL Electric's ATRR is based on actual costs for transmission service for the preceding calendar year and based on associated FERC Form No. 1 data. PPL Electric is allowed to include the cost of weighted, capital additions projected for the current year, as well as projected CWIP for its transmission incentive project, Susquehanna-Roseland. PPL Electric also has a true-up mechanism through which deviations from actual costs will be addressed.

The ATRR produced by PPL Electric's approved formula rate is the sum of return on rate base, operation and maintenance expense, administrative and general expense, depreciation expense, taxes other than income tax, and income taxes, less any applicable revenue credits. PPL Electric's formula rate components are based on FERC Form No. 1 data and/or supporting documentation for data not otherwise available in the FERC Form No. 1. PPL Electric's Regulatory Compliance group manages the formula rate filing process, while other groups such as Transmission Expansion, Office of General Counsel, and Taxes provide data and various exhibits supporting some components. PPL Electric's formula rate filing is submitted to the Commission as an informational filing, due annually on or before May 15 of each year.

C. Summary of Compliance Findings

Audit staff's compliance findings are summarized below. Details are in section IV of this report. Audit staff identified the following areas of noncompliance:

- PPL Electric improperly accounted for its investment in PPL Receivables Corporation under the consolidated method of accounting instead of using the equity method of accounting, as required by the Commission. As a result of using the consolidated method instead of the equity method of accounting, PPL Electric erroneously included certain amounts in its formula rate billings to wholesale transmission customers.

- PPL Electric improperly accounted for overpayments of its current year's estimated Federal and state income taxes in Account 165, Prepayments.

- PPL Electric improperly accounted for manufactured gas plant remediation expenses in Account 930.2, Miscellaneous General Expenses. These expenses should have been accounted for so that no amounts would be recovered from wholesale transmission customers since these costs were not associated with obligations related to wholesale transmission customers. As a result of the incorrect accounting, these expenses were improperly included in the formula rate computation.

- KU and LG&E neither sought nor received Commission approval to recover asset retirement obligation costs in their transmission formula rate.

- KU did not remove all amounts from its formula rate calculations associated with its Virginia distribution utility plant facilities, as required by the Commission.

- KU and LG&E improperly accounted for cost of removal on physical assets related to asset retirement obligations.

- PPL's three franchised public utilities (KU, LG&E, and PPL Electric) incorrectly included some transaction-related costs related to PPL's merger with E.ON U.S. in formula rate billings to wholesale power and transmission customers.

- KU's method of computing Allowance for Funds Used During Construction (AFUDC) on Construction Work In Progress (CWIP) was deficient by compounding AFUDC monthly instead of semi-annually, including unrealized losses in its common equity balance used to calculate AFUDC, and using an incorrect balance for the common equity component.

- KU and LG&E's formula rate Attachment O included multiple inaccurate line references.

- FERC Form No. 60 filings that PPL Services Corporation (PPL Services) and LG&E and KU Services Company (LKS) made contained several reporting errors relating to account misclassifications, supporting schedule discrepancies, and the reporting of convenience payments.

D. Summary of Recommendations

Audit staff's recommendations to remedy the findings are summarized below. Detailed recommendations are in section IV. To address the areas of noncompliance, audit staff recommends the following:

1. PPL Electric should provide notice of its material accounting changes to its wholesale transmission customers as required by section III.B of Attachment H-8H, Formula Rate Implementation Protocols, of its Open Access Transmission Tariff.

2. PPL Electric should implement procedures to ensure that it follows the equity method of accounting for all investments in subsidiaries and ensure no deviation between accounting practices and Commission accounting regulations.

3. PPL Electric should adopt controls that will ensure all costs related to PPL Receivables' operating activities are excluded from all components in PPL Electric's formula rate calculation.

4. PPL Electric should refund all costs incorrectly included in and recovered through the formula rate since its inception, with interest, calculated in accordance with the formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

5. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

6. PPL Electric should reclassify Federal and state income taxes recorded in Account 165, Prepayments, applicable to those years in which PPL Electric chose to receive a refund of those amounts to Account 146, Accounts Receivable from Associated Companies, or Account 143, Other Accounts Receivable, as appropriate.

7. PPL Electric should submit correcting entries to the Division of Audits and Accounting within 30 days of this report.

8. PPL Electric should revise procedures to ensure its income tax transactions recorded to Account 165 represent actual prepayments.

9. PPL Electric should revise procedures to appropriately determine its tax accrual amount.

10. PPL Electric should record the necessary correcting entries as of December 31 to reflect the proper accounting for Federal and state estimated tax overpayment.

11. For each year these amounts were included in the formula rate calculations, PPL Electric should refund all costs incorrectly included in and recovered through the formula rate, with interest, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

12. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

13. PPL Electric should amend its accounting policies to ensure manufactured gas plant remediation expenses are accounted for consistent with the Commission's accounting regulations.

14. PPL Electric should refrain from including manufactured gas plant remediation expenses in the formula rate determinations, since such costs were not incurred in providing service to wholesale transmission customers.

15. PPL Electric should determine the amount of manufactured gas plant remediation costs recovered through its formula rate.

16. For each year affected, PPL Electric should refund the manufactured gas plant remediation expense amounts improperly included and recovered through the formula rate, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

17. PPL Electric should file a refund report with the Commission that reflects amounts refunded to its wholesale transmission customers.

18. LG&E and KU should submit a filing with the Commission under FPA section 205 to address their recovery of asset retirement obligation costs.

19. LG&E and KU should calculate the rate impact of recovering these ARO costs in the formula rate, and provide these calculations to the Division of Audits and Accounting.

20. For each year affected since the inception of their stand-alone formula rate, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to recovering asset retirement obligation costs, calculated with interest under section 35.19a of the Commission's regulations.

21. LG&E and KU should calculate the rate impact of recovering these costs in their stand-alone formula rate, and provide these calculations to the Division of Audits and Accounting.

22. For each year these Virginia distribution utility costs were included in their stand alone formula rate calculation, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate, calculated with interest under section 35.19a of the Commission's regulations.

23. LG&E and KU should provide to the Division of Audits and Accounting correcting entries that show the reversal of amounts from Account 254.

24. For each year these amounts were included in their stand-alone formula rate, LG&E and KU should refund all costs, calculated with interest under section 35.19a of Commission regulations.

25. LG&E and KU should file a refund report with the Commission that reflects amounts refunded to their customers.

26. PPL Electric, LG&E, and KU should strengthen existing procedures so that no transaction-related costs flow through an FPU's formula rates.

27. PPL Electric, LG&E, and KU should calculate the rate impact of recovering transaction-related costs in their respective formula rates, and provide these calculations to the Division of Audits and Accounting.

28. PPL Electric, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to the incorrect allocation of transaction-related costs, calculated with interest in accordance to the Commission-approved formula rate protocols for PPL Electric and under section 35.19a of the Commission's regulations for LG&E and KU.

29. KU should revise and implement procedures going forward to ensure its AFUDC base and rate calculation is consistent with Electric Plant Instruction 3(17) and other applicable Commission requirements.

30. LG&E and KU should develop and implement controls to ensure accurate and complete line references.

31. LG&E and KU should submit a filing with the Commission under FPA section 205 to address the incorrect formula rate line references.

32. LKS and PPL Services should develop and implement procedures to ensure proper account classification, consistent reporting, and completion of all supporting schedules of the FERC Form No. 60. As part of these procedures, incorporate an annual review to ensure the FERC Form No. 60 filed with the Commission is complete and accurate.

33. LKS and PPL Services should refile 2010 FERC Form No. 60, correcting all reporting errors within 90 days after this report is issued.

E. Compliance and Implementation of Recommendations

Audit staff further recommends that PPL:

- Submit its plans for implementing audit staff's recommendations for audit staff's review. PPL should submit these plans to audit staff within 30 days after this final audit report is issued.

- Submit all correcting entries to the Division of Audits and Accounting within 30 days after this final audit report is issued, including all correcting entries affecting the books for its associated franchised public utilities.

- Submit quarterly reports to the Division of Audits and Accounting describing PPL's progress in completing each corrective action recommended in this final audit report. PPL should make quarterly filings no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report in this docket is issued, and continuing until PPL completes all recommended corrective actions.

- Submit copies of any written policies and procedures developed in response to recommendations in the final audit report. These policies and procedures should be submitted for audit staff review in the first quarterly filing after PPL completes these products.

II. Background Information

A. Description of PPL Corporation System

Headquartered in Allentown, PA, PPL is a public utility holding company with public utility and nonutility subsidiaries in the United States. PPL controls or owns approximately 19,000 megawatts of generating capacity in the United States, sells energy in U.S. markets, and delivers electricity and natural gas to about 10 million customers in the United States. PPL also owns a regulated distribution company in the United Kingdom that serves 7.8 million customers in Wales, and southwest and central England. During the audit period, PPL was the parent of three Commission-jurisdictional franchised public utilities (FPUs): PPL Electric, LG&E, and KU.[6]

PPL Electric delivers electricity to 1.4 million customers in eastern and central Pennsylvania, and owns transmission facilities within PJM's balancing authority area. PPL Electric does not have captive wholesale or retail customers, but is the default supplier for retail customers within its service area. LG&E is a public utility that owns and operates electric generation, transmission, and distribution facilities, as well as natural gas distribution, transmission, and storage facilities, in Kentucky and Indiana. LG&E serves 397,000 electric customers. KU is a public utility that owns and operates electric generation, transmission, and distribution facilities in Kentucky, with limited operations in Tennessee and Virginia. KU serves 516,000 electric customers in Kentucky and 30,000 electric customers in Virginia.

PPL's two centralized service company subsidiaries (LKS and PPL Services) provide a variety of services to PPL, affiliated FPUs, and other affiliates.

LKS provides a variety of administrative, management, engineering, construction, environmental, and support services to affiliated entities, including KU and LG&E, at cost. LKS was formed as a Kentucky corporation on June 2, 2000 and commenced operations as a service company on January 1, 2001. Following the repeal of the Public Utility Holding Company Act (PUHCA) of 1935 and the enactment of PUHCA 2005, LKS transitioned, effective January 1, 2008, to the Commission's USofA for centralized service companies under part 367. LKS is a wholly owned subsidiary of LG&E and KU Energy LLC (LKE), which in turn is a wholly owned subsidiary of PPL. LKS became an indirect, wholly owned subsidiary of PPL when PPL acquired all of the limited liability company's interest of LKE from E.ON U.S. LLC (E.ON U.S.) on November 1, 2010.

[6] The term franchised public utility means a public utility with a franchised service obligation under state law.

PPL Services, a Delaware corporation, is a wholly owned subsidiary of PPL. PPL Services also provides various administrative services at cost to affiliated entities, including LKS and PPL Electric. PPL Services was formed as a corporate entity on February 14, 2000 as a PPL subsidiary. When PPL Services was formed, PPL was a single state exempt holding company under PUHCA 1935, so PPL Services was not subject to regulation as a centralized service company. PPL remained a single state exempt holding company after PUHCA 2005 was passed. On October 26, 2010, the Commission issued an order under section 203 of the Federal Power Act (FPA), authorizing PPL's acquisition of E.ON U.S. As a result of the acquisition of E.ON U.S., PPL derived more than 13 percent of its public utility company revenues from outside of a single state. After the acquisition, PPL notified the Commission that it no longer qualified for the waiver from applicable accounting, record retention, and reporting requirements under part 366 of the Commission's regulations as a single state holding company and notified the Commission it no longer sought to maintain its waiver as a single state holding company. Due to the acquisition of E.ON U.S. and PPL's change in status under PUHCA 2005, PPL Services fell under regulation as a centralized service company under PUHCA 2005 on November 1, 2010. The basic organizational structure of PPL Services has not changed significantly since it was formed in 2000.

B. Non-Power Goods and Services

LKS and PPL Services are the centralized service companies within PPL's holding company system that provide business support services to PPL, affiliated FPUs, and other subsidiaries. During the audit period, the service companies had service agreements between themselves and the FPUs. Under these agreements, the service companies provided administrative and professional services to PPL, its associated public utilities, and other PPL nonregulated operating companies "at-cost." Specifically, these administrative and professional services included, among others, corporate audit services, environmental management services, facilities management, financial accounting and reporting services, human resources, IT support, tax services, and legal services. Also, affiliated companies provided PPL's FPUs with other non-power goods and services. Such services were provided under agreements for mutual assistance, gas transportation services, insurance services, third-party services, data hosting, and intercompany billing support.

C. Service Company Accounting Systems

Cost accumulation and tracking at PPL Services is accomplished using two systems: PeopleSoft Project Costing (Project Costing) and PowerPlant. Project Costing is the system where projects are created and serves as the repository for amounts from various subsystems, such as payroll, accounts payable, and inventory. PPL Services tracks expenses by project. These can either be expense or capital projects. The Commission account for applicable costs is assigned as part of this Project Costing. PowerPlant contains plant records for PPL Services and serves as the database for its property records. PowerPlant data fields are updated by a nightly interface with PeopleSoft. Any capital projects established in PowerPlant are reviewed for proper accounting set up by the Asset Management group, which is part of the Controller's department. PowerPlant calculates depreciation expense as well as any capitalized interest. At month end, PowerPlant creates journal entries that are interfaced back to the PeopleSoft general ledger. PowerPlant is used exclusively for accumulating costs for capital projects.

Classification of accounts is maintained by the Corporate Accounting department in the Shared Accounting Services group and conforms to the requirements of the USofA. The classification also establishes accounting requirements as applicable to transactions occurring under normal circumstances in the ordinary course of business. The general ledger records and maintains activity and balances for direct and indirect costs. The general ledger also runs a monthly process to allocate indirect service company costs recorded, by category, from the service company to various PPL business lines as defined by the Financial Planning group. Also, the Financial Planning group created manual journal entries, and reviewed and approved direct cost allocations from the service company to the various business lines.

LKS cost accumulation and tracking is accomplished using Oracle products. Transactions affecting LKS post to the Oracle general ledger and originate from spreadsheet journal entries and mass allocations generated within the Oracle general ledger module, and from the subsidiary systems' Oracle Project Accounting, Oracle Payables, Oracle Purchasing, PowerPlant, the VOLTS timekeeping system, and the Transportation Resource Management System.

LKS uses the Oracle Project Accounting (Project Accounting) module to capture and accumulate direct and indirect costs. Projects have been created for each associated company, which receives charges with tasks designated to record income statement charges for direct and indirect labor, and for direct and indirect nonlabor. Charges from LKS to projects with tasks set up to balance sheet accounts on associated companies are designated as direct. Labor burdens are designated as indirect, consistent with the treatment on the FERC Form No. 1. LKS employees record their time through the timekeeping system to the appropriate direct or indirect labor tasks, and the labor is interfaced to Project Accounting and the general ledger. Nonlabor charges are recorded to appropriate direct or indirect nonlabor tasks via coding on purchase orders, disbursement requests, purchasing cards, or expense reports. After employees' labor charged to associated companies is interfaced from Project Accounting and posted to the general ledger, an Oracle process calculates burden components on this labor. This process debits direct burden accounts for all labor, including indirect labor. Another Oracle process then moves burden amounts from direct burden accounts to indirect burden accounts.

D. Cost Allocation Methods

The service companies directly and indirectly charge costs to affiliates. Directly charged costs are identifiable and charged entirely to the appropriate affiliate, while indirectly charged costs require application of different cost allocation methodologies to determine charges. These methodologies are based on several factors such as number of employees, number of transactions, number of customers, or occupied square footage. In general, the service companies charge costs to affiliates in one of three ways:

- Costs for services performed for an affiliate are directly charged to the affiliate.
- Costs for services performed for two or more affiliates are distributed among and charged to the affiliates, using methods determined on a cost-causation basis consistent with the type of work performed and based on an allocation method.
- Costs for general services, which are applicable to all affiliates or a class or classes of affiliates, are allocated among or charged to such affiliates by application of one or more cost allocation methods.

LKS reported approximately $296 million in service costs for 2011. Moreover, LKS directly charged some 47 percent and allocated 53 percent of costs to affiliates with respect to non-power goods and services it provided. KU and LG&E received about 88 percent of the service company's charges during 2011. LKS neither directly charged nor allocated any costs to PPL Electric during 2011. LKS directly charged or allocated costs to affiliates using 18 different allocation methods.

PPL Services reported approximately $400 million in service costs for 2011. Moreover, it directly charged some 59 percent and allocated 41 percent of costs to affiliates with respect to non-power goods and services it provided. PPL Electric received about 36 percent of the service company's charges during 2011. PPL Services neither directly charged nor allocated any costs to KU or LG&E during 2011. PPL Services directly charged or allocated costs to affiliates using 11 different allocation methods.

E. Internal Audit Role and Reporting

PPL's Internal Audit department is divided into three branches: PPL Audit Services, Special Projects, and LKE Audit Services. The executive director of the Internal Audit department reports functionally to the Audit Committee of the Board of Directors and reports administratively to the Chairman/President/CEO. Most of these staffers have Certified Public Accountant and/or Certified Internal Auditor professional certifications.

The Internal Audit department uses and complies with the Institute of Internal Auditors' International Standards for the Professional Practice of Internal Auditing. Each quarter, the Internal Audit department prepares a report for the PPL Audit Committee that addresses key risk areas assessed during the quarter, a summary of audit results, a summary of significant or material control deficiencies, audit performance measures, and a summary of select in-progress audits. Each year, the Internal Audit department also reports to the PPL Audit Committee on overall control environment, Sarbanes-Oxley section 404 compliance, audit organization and qualifications, budget and expenditures, annual audit plans, and the Internal Audit department's charter. The Internal Audit department did not perform any work that directly related to the scope areas in this audit.

F. Acquisition of E.ON U.S.

On November 1, 2010, PPL purchased E.ON U.S., the parent company of Kentucky's two major utilities, KU and LG&E, for $7.625 billion from German utility firm E.ON AG. On October 25, 2010, the Commission issued an order approving this acquisition of all issued and outstanding limited liability company interests of E.ON U.S.[7] As a result of the transaction, E.ON U.S. became a direct, wholly owned subsidiary of PPL, and E.ON U.S.'s subsidiaries, including KU and LG&E, became indirect, wholly owned subsidiaries of PPL. In its Merger Order approving the transaction, the Commission required that transmission and wholesale customers be held harmless from costs related to the transaction for five years to the extent that such costs would exceed savings related to the transaction.

[7] *PPL Corporation*, 133 FERC ¶ 61,083 (2010) (Merger Order).

III. Introduction

A. Objectives

The audit's objectives were to determine whether PPL and its associated companies complied with: (1) Commission cross-subsidization restrictions on affiliate transactions; (2) accounting, recordkeeping, and reporting requirements; (3) the USofA for centralized service companies; (4) Commission preservation of records requirements for holding companies and service companies; and (5) FERC Form No. 60 Annual Report requirements. The audit evaluated PPL's associated public utilities' compliance with Commission accounting requirements for transactions with associated companies and applicable reporting requirements in the FERC Form No. 1. The audit also evaluated compliance with the conditions upon which the Commission granted merger and acquisition of jurisdictional facilities authorizations in Docket No. EC10-77-000. Lastly, audit staff examined KU, LG&E, and PPL Electric's compliance with their transmission cost-of-service formula rate schedules within the respective OATTs. The audit covered January 1, 2010 through December 31, 2011.

B. Scope and Methodology

To address overall audit objectives, audit staff:

- Identified standards and criteria used to evaluate compliance with each audit scope area. They included Commission rules, regulations, letter orders, and other requirements for holding and service companies, and Commission accounting regulations for jurisdictional public utilities.

- Reviewed FERC-65, Notification of Holding Company Status, and FERC Form No. 60 Annual Reports to ensure filed information was reliable, accurate, and complete.

- Reviewed publicly available materials to understand PPL's operations, including select filings to the SEC (Forms 10-K and 10-Q), FERC Form Nos. 1 and 60 filings, prior audits, and other filings with the Commission.

- Conferred with officials from the Pennsylvania, Kentucky, Virginia, and Tennessee public utility commissions, which have jurisdiction over PPL's FPUs.

- Conducted site visits to corporate headquarters in Allentown, PA, and Louisville, KY. The visits enabled audit staff to understand PPL's structure, activities, functions, systems, and the processes used in its operations. While on site, audit staff reviewed and tested supporting details for PPL's allocation methods; interviewed PPL staff responsible for accounting, financial reporting, record retention, cost allocations, and PPL's compliance program; sampled select supporting documents to ensure the service companies' accounting complied with Commission accounting regulations; sampled select supporting documents to ensure that billings and associated public utilities' accounting for these billings complied with Commission accounting regulations; and tested compliance with preservation of records requirements.

- Conducted interviews, teleconferences, and met with PPL employees to discuss processes, procedures, operations, and observations.

- Discussed data responses with PPL employees, and clarified and supplemented data responses with more information on areas of specific concern.

- Reviewed relevant audit reports and working papers of the Internal Audit department and external audit firm Ernst & Young LLP.

- Conferred with other Commission staff on various compliance issues to ensure audit findings would be consistent with Commission precedent and policy. For example, audit staff spoke with staff from other divisions within the Office of Enforcement, and with technical and legal staff from other Commission offices, including the Office of Energy Market Regulation and the Office of General Counsel.

Audit staff performed several specific actions to evaluate compliance with all relevant requirements relating to audit objectives. A summary of these actions includes:

Cross-subsidization Restrictions

To evaluate compliance with Commission cross-subsidization restrictions on affiliate transactions, audit staff:

- Reviewed policies, procedures, and practices related to the sale of non-power goods and services.

- Interviewed PPL employees, particularly those who account and report transfers of non-power goods and services.

- Reviewed and tested pricing mechanisms for non-power goods and services the FPUs provided to and received from each other, service companies, and other nonutility affiliates.

- Sampled charges and payments to determine accurate pricing for the sale of goods and services.

Accounting, Recordkeeping, and Financial Reporting

To evaluate compliance with Commission accounting, recordkeeping, and financial reporting regulations, audit staff:

- Reviewed FERC Form No. 60 Annual Report filings, Notification of Holding Company Status – FERC-65 filings, and the public utilities' FERC Form No. 1 reports. Audit staff also verified select, electronically filed information reported on the FERC Form No. 60 filings with supporting books and records to ensure reported information was accurate and complete.

- Compared select information in the FERC Form No. 1s with the FERC Form No. 60s to ensure information was reported accurately and consistently. Also, audit staff reviewed page 429 of the FERC Form No. 1s, which included non-power goods and services transactions for each FPU.

- Reviewed, sampled, analyzed, and tested select centralized service company accounting data.

- Sampled FPUs' accounting for select costs received from the centralized service companies.

Cost Allocation and Billings

To evaluate service company cost allocation methodologies and billings, audit staff:

- Identified cost allocation methods used, and identified and reviewed new allocation methods to facilitate our review of the service companies' cost allocation methods and costs the service companies billed to PPL's FPUs. Also, audit staff reviewed and tested billings and supporting details behind select allocation methods.

Preservation of Records

To evaluate compliance with Commission preservation of records requirements, audit staff:

- Interviewed PPL employees responsible for retaining records for the service companies.

- Requested and tested select records to ensure their retention.

Merger and Acquisition Authorizations Compliance Review

To evaluate compliance with conditions of the Commission's Merger Order, audit staff:

- Reviewed PPL's applications and related Commission filings and orders to understand the terms, conditions, and context of the merger and acquisition request, and identify commitments made in applicable orders.

- Examined procedures and controls for compliance with "hold harmless" provisions the Commission established in its merger and acquisition order. This included a review of accounting filings for recovery of transaction-related costs, controls for compliance oversight, and rates to ensure cost recoveries were appropriate.

- Discussed the merger with state public utility commissions that regulate PPL to understand their merger oversight and any concerns related to the post-merger company.

- Evaluated PPL's implementation process to ensure compliance with the merger's hold harmless provisions, requiring PPL to hold wholesale power and transmission customers harmless for five years from merger costs that may exceed merger-related savings.

- Interviewed employees involved in merger costs and synergy savings tracking.

- Tested certain amounts recorded as merger costs and synergy savings to determine appropriate classification and the level of support maintained.

Transmission Formula Rate

To evaluate each FPU's compliance with its respective formula rates, audit staff:

- Evaluated PPL Electric's compliance with its transmission cost-of-service formula rate in Attachment H-8G and the related Protocols set forth in Attachment H-8H to PJM's OATT, and KU and LG&E's compliance with their transmission cost-of-service formula rate in Attachment O to their joint OATT, including filings containing inputs to the formula rate.

- Reviewed initial and all subsequent Commission orders accepting the formula rate, including orders approving related settlements and PPL filings. Determined the level of functionalization, derivation of allocation factors, return on equity, rate base, accumulated depreciation, and other expenses. Reviewed background information about specific cost treatment, deferrals, cost caps, disallowances, and other matters disclosed as part of approving the derivation of the formula rate.

- Evaluated processes, procedures, and controls used to prepare and review the formula rate and annual updates, true-ups, or informational filings associated with the formula rate.

- Reviewed formula rate mechanics (forward-looking, historical, true-up, and informational filings), including a comprehensive overview of the formula rate mechanism the company provided.

- Evaluated the FERC Form No. 1 reporting processes and procedures to ensure accurate and complete reporting. As part of this evaluation, audit staff reconciled FERC Form No. 1 data with formula rate calculations and reviewed all discrepancies.

- Reviewed the FERC Form Nos. 1 and 3-Q, including related notes to financial statements to identify major accounting matters. Audit staff highlighted significant notes to understand financial statement and formula rate implications, and identified underlying accounting entries for these significant accounting matters.

- Determined whether the FPUs' accounting for significant matters impacted the formula rate calculation.

- Evaluated whether PPL's FPUs applied formula rate inputs in compliance with rate approval orders.

- Reconciled formula rate inputs derived from the FERC Form No. 1 to FPU books and records. Evaluated compliance with the USofA for the inputs under review, including all related guidance and accounting releases and accounting treatment of input items.

- Evaluated various accounts incorporated into cost-of-service formula rates and compliance with relevant accounting regulations in the UsofA.

Besides these actions, audit staff reviewed PPL's regulatory compliance program. Audit staff assessed the program for audit scope areas consistent with prior Commission orders and policy statements. Specifically, audit staff:

- Reviewed PPL's regulatory compliance program structure, including its authority and responsibilities for overseeing corporate compliance and the delegation of compliance responsibilities.

- Reviewed the Internal Audit department structure, including its chain-of-command and access to the Board of Directors through its Audit Committee to assess the effectiveness and independence of the audit function.

- Interviewed PPL executives, managers, and operational employees to evaluate their knowledge and application of the compliance program.

IV. Findings and Recommendations

1. Long-Term Investment in Subsidiary

PPL Electric improperly accounted for its investment in PPL Receivables under the consolidated method of accounting instead of using the equity method of accounting, as required by the Commission. As a result of using the consolidated method instead of the equity method of accounting, PPL Electric erroneously included certain amounts in its formula rate billings to wholesale transmission customers.

Pertinent Guidance

On February 1, 1973, the Commission issued Order No. 469 to amend the requirements of the Uniform System of Accounts to adopt the equity method of accounting for long-term investments in subsidiaries.[8]

18 C.F.R. pt. 101, Account 123.1, Investment in Subsidiary Companies, states:

> A. This account shall include the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.

18 C.F.R. pt. 101, Account 418.1, Equity in Earnings of Subsidiary Companies, states:

> This account shall include the utility's equity in the earnings or losses of subsidiary companies for the year.

Instructions to the schedule on page 224 of the FERC Form No. 1, Investments in Subsidiary Companies (Account 123.1), require in part:

> 1. Report below investments in Accounts 123.1, Investments in Subsidiary Companies.

[8] *Revisions in the Uniform System of Accounts, and Annual Report Forms No. 1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326 (1973), *rehearing denied*, 49 FPC 1028 (1973).

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

PJM Interconnection L.L.C., FERC Electric Tariff, Attachment H-8H, sections I, III.B states, in part:

> I.H "Material Accounting Change" means any (i) change in PPL Electric's accounting policies and practices, or (ii) change in PPL Electric's inter-corporate cost allocation policies or practices from those policies and/or practices in effect for the Rate Year upon which the immediately preceding Annual Update was based, which change causes a result under the Formula Rate difference than the result under the Formula Rate as calculated without such change.
>
> III.B. (2) The Annual Transmission Revenue Requirement shall be based on PPL Electric's books and records which reflect data properly recorded in: PPL Electric's FERC Form No. 1 to the extent the Formula Rate specifies the FERC Form No. 1 data as the input source; and The Commission's Uniform System of Accounts, as each exists as of the last day of the preceding calendar year.
>
> III.B. (3)(b) The Annual Update shall provide notice of Material Accounting Changes, which may incorporate by reference applicable disclosure statements filed with the SEC.

Background

Since 1973, the Commission has adopted the equity method of accounting for long-term investments in subsidiaries. Under the equity method of accounting, the investment in subsidiaries is recorded in Account 123.1, Investment in Subsidiary Companies (Major Only).[9] This account is increased or decreased based on a utility's proportionate share of subsidiary earnings regardless of whether such earnings were paid out as dividends to that utility. Although the Commission adopted the equity method of accounting for long-term investment in subsidiaries, it maintained its policy for ratemaking purposes that undistributed earnings of the subsidiary are to be excluded from the equity portion of the jurisdictional company capital structure in determining the rate of return.

[9] *Id*.

PPL Electric has three investments in the following subsidiary companies: CEP Commerce, LLC (CEP Commerce), CEP Lending, Inc. (CEP Lending), and PPL Receivables Corporation (PPL Receivables). PPL Electric has full control of these entities through 100 percent ownership of direct voting rights. CEP Commerce is the parent of CEP Lending, a company formed to make intercompany loans to all of PPL affiliates. PPL informed audit staff that PPL Receivables was formed to serve only the financing needs of PPL Electric. PPL Receivables is a special purpose entity whose sole purpose is to buy eligible accounts receivable and unbilled revenue from PPL Electric to secure asset-backed commercial paper from a third party.

Audit staff examined PPL Electric's accounting for its long-term investment in subsidiaries and found that it used the equity method of accounting to account for its long-term investment in CEP Commerce and CEP Lending. Conversely, it used the consolidated method of accounting to account for its long-term investment in PPL Receivables since its inception in 2004.

PPL Electric used various income statement and balance sheet accounts to record its long-term investment in PPL Receivables under the consolidated method of accounting. During the course of the audit fieldwork, PPL Electric filed its 2012 FERC Form No. 1 as required by Commission regulations.[10] On page 450.1 of the refiled 2012 FERC Form No. 1, PPL Electric disclosed the accounting impact if it had followed the Commission's approved method of accounting for subsidiary investments, which was the equity method of accounting. In addition, audit staff noted that some of these accounts and associated amounts flowed through the formula rate billings to transmission customers.

Audit staff determined that PPL Electric appropriately accounted for its long-term investment in CEP Commerce and CEP Lending using the equity method of accounting. However, PPL Electric did not properly account for its long-term investment in PPL Receivables based on the equity method of accounting, as required by Commission accounting regulations. The Commission's accounting regulations require that long-term investments in subsidiaries be recorded in Accounts 123.1 and 418.1, Equity in Earnings of Subsidiary Companies. Also, PPL Electric should not have included certain amounts in formula rate billings to wholesale transmission customers associated with using the consolidated method of accounting for PPL Receivables. Lastly, audit staff did not find sufficient evidence demonstrating that PPL Electric provided notification to its customers that it was using an accounting method not prescribed by the Commission to account for its long-term investment in PPL Receivables using the consolidated versus the equity method of accounting.

[10] 18 C.F.R. section 141.1.

Since PPL Electric neither sought nor received retroactive relief to use the consolidated method of accounting for its subsidiary investment in PPL Receivables, it must refund amounts erroneously included in formula rate billings to transmission customers since 2004.

Recommendations

We recommend that:

1. PPL Electric should provide notice of its material accounting changes to its wholesale transmission customers as required by section III.B of Attachment H-8H, Formula Rate Implementation Protocols, of its Open Access Transmission Tariff.

2. PPL Electric should implement procedures to ensure that it follows the equity method of accounting for all investments in subsidiaries and ensure no deviation between accounting practices and Commission accounting regulations.

3. PPL Electric should adopt controls that will ensure all costs related to PPL Receivables' operating activities are excluded from all components in PPL Electric's formula rate calculation.

4. PPL Electric should refund all costs incorrectly included in and recovered through the formula rate since its inception, with interest, calculated in accordance with the formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

5. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

2. Tax Overpayments

PPL Electric improperly accounted for overpayments of its 2010 and 2011 estimated Federal and state income tax liability in Account 165, Prepayments.

Pertinent Guidance

18 C.F.R. pt. 101, Account 236(A) (B), Taxes Accrued, states:

> A. This account shall be credited with the amount of taxes accrued during the accounting period, corresponding debits being made to the appropriate accounts for tax charges. Such credits may be based upon estimates, but from time to time during the year as the facts become known, the amount of the periodic credits shall be adjusted so as to include as nearly as can be determined in each year the taxes applicable thereto. Any amount representing a prepayment of taxes applicable to the period subsequent to the date of the balance sheet, shall be shown under account 165, Prepayments.
>
> B. If accruals for taxes are found to be insufficient or excessive, correction therefore shall be made through current tax accruals.

Background

Audit staff reviewed PPL Electric's taxes and related procedures to understand why PPL Electric characterized taxes as prepaid. Specifically, audit staff asked PPL Electric to explain: (1) the calculation of its estimated Federal and state income tax liability each year; (2) the procedures for determining its estimated and actual Federal and state income tax liability; and (3) the documentation supporting its estimated and actual Federal and state income tax liability and Federal and state income tax prepayment determinations for 2010 and 2011.

PPL Electric determined its estimated Federal and state income tax liability each month by applying the applicable Federal and state income tax rates to its estimated taxable income. When quarterly income tax payments exceeded the estimated income tax liability, PPL Electric considered the income tax overpayment as a prepayment and then recorded this amount in Account 165. PPL Electric paid estimated Federal and state income taxes in four quarterly installments based on its estimated annualized taxable income.

Based on the examination of tax information, audit staff found that PPL Electric recorded Federal and state income tax overpayment amounts in Account 165 that were refunded to PPL Electric for tax years ending 2010 and 2011. Specifically, PPL Electric received refunds amounting to $59,843,908 and $17,272,745 for tax years 2010 and 2011, respectively. Thus, PPL Electric did not reduce any future year's tax liability by the 2010 and 2011 income tax overpayments.

While Account 165 of the Commission's accounting regulations allows the prepayment of income taxes to be recorded therein, Account 236 requires that such prepayments must be applicable to periods subsequent to the date of the balance sheet. Further, the Commission has defined prepayments included in Account 165 as expenses for a service or a supply paid in advance that will be consumed or used in future accounting periods, such as rent and insurance.[11] Audit staff believes PPL Electric's treatment of income tax overpayments as a prepayment is not consistent with the requirements of Account 165 or other Commission requirements because these monies were refunded and not used to pay PPL Electric's income tax obligations in advance.

PPL Electric included the income tax overpayments recorded in Account 165 in its formula rate as a component of rate base. Under the PJM OATT, PPL Electric is allowed to include prepaid amounts recorded to Account 165, Prepayments, as an item in the derivation of its rate base calculated in its formula rates. Prepayments, which represent amounts paid in advance for a good or service, are included as an adjustment to rate base and serve as an added benefit to transmission owners for costs essential to their operations but are prepaid, like insurance premiums. PPL Electric's prepayment input was the product of its applicable prepayment balance and its wages and salaries allocation factor. In conformance with notes to PPL Electric's formula rate, it can only include prepayments for its electric operations.

Because PPL Electric elected not to apply the income tax overpayments to future tax obligations, it should not have been reclassifying excess tax payments in Account 236 to Account 165. Audit staff is aware that PPL Electric engaged in this accounting practice during and prior to the audit period. Also, PPL Electric should not have recovered amounts for its overpayment of income taxes through its formula rate. For amounts determined to be potential refunds and not used to pay PPL Electric's tax obligations in advance, PPL Electric should reclassify state income tax prepayments to Account 143, Other Accounts Receivable, and Federal income tax prepayments to Account 146, Accounts Receivable from Associated Companies.

[11] *Entergy Services, Inc.*, Opinion No. 505, 130 FERC ¶ 61,023, at P 190 (2010).

Recommendations

We recommend that:

6. PPL Electric should reclassify Federal and state income taxes recorded in Account 165, Prepayments, applicable to those years in which PPL Electric chose to receive a refund of those amounts to Account146, Accounts Receivable from Associated Companies or Account 143, Other Accounts Receivable, as appropriate.

7. PPL Electric should submit correcting entries to the Division of Audits and Accounting within 30 days of this report.

8. PPL Electric should revise procedures to ensure its income tax transactions recorded to Account 165 represent actual prepayments.

9. PPL Electric should revise procedures to appropriately determine its tax accrual amount.

10. PPL Electric should record the necessary correcting entries as of December 31 to reflect the proper accounting for Federal and state estimated tax overpayment.

11. For each year these amounts were included in the formula rate calculations, PPL Electric should refund all costs incorrectly included in and recovered through the formula rate, with interest, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

12. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric’s wholesale transmission customers.

3. Manufactured Gas Plant Obligations

PPL Electric improperly accounted for manufactured gas plant remediation expenses in Account 930.2, Miscellaneous General Expenses. As a result of the incorrect accounting, these expenses were improperly included in the formula rate computation. These expenses should have been treated such that no amounts would be recovered from wholesale transmission customers since these costs were not associated with providing service to wholesale transmission customers.

Pertinent Guidance

18 C.F.R. pt. 101, Account 242, Miscellaneous Current and Accrued Liabilities, states:

> This account shall include the amount of all other current and accrued liabilities not provided for elsewhere appropriately designated and supported so as to show the nature of each liability.

18 C.F.R. pt. 101, Account 253, Other Deferred Credits, states:

> This account shall include advance billings and receipts and other deferred credit items, not provided for elsewhere, including amounts which cannot be entirely cleared or disposed of until additional information has been received.

18 C.F.R. pt. 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

18 C.F.R. pt. 101, Account 930.2, Miscellaneous General Expense, states:

> This account shall include the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere.

Background

PPL Electric incurred manufactured gas plant (MGP) environmental obligations to clean up contaminated sites in conjunction with the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. This act imposed joint and several liability for cleaning up contamination caused by hazardous substances. PPL Electric estimated its liability for MGP environmental remediation to be $3,874,758 and $696,010 in 2010 and 2011, respectively. PPL Electric accounted for the MGP environmental remediation contingencies by debiting Account 930.2, and crediting Account 242 or Account 253, as appropriate.

PPL Electric represented that it included the environmental remediation obligations related to the MGPs in Account 930.2 because the environmental costs could not be identified with a specific business line. Consistent with PPL Electric's accounting policy, when a specific business line cannot be identified, either due to contamination that related to the purchase of property or related to former operation of facilities no longer in service, the costs are recorded in Account 930.2.

Audit staff believes that PPL Electric's accounting for its MGP environmental obligations was not consistent with the Commission's accounting regulations because such obligations should not have been included in Accounts 930.2. Audit staff also noted that these costs were not related to providing service to wholesale transmission customers. Therefore, under the Commission's accounting regulations, PPL Electric should have accounted for the MGP environmental obligations by debiting the appropriate nonutility expense account, not a transmission or administrative and general expense account tied to the transmission formula rate, and crediting Account 242 or Account 253, as appropriate.

For ratemaking purposes, PPL Electric included amounts in Account 930.2 in formula rate determinations. The formula rate template permits PPL Electric to recover costs recorded in this account through the application of the transmission wages and salaries allocator. The transmission wages and salaries allocator is the ratio of transmission wages expense to total wages expense less administrative and general wages expense. The application of this allocation factor allowed PPL Electric to recover transmission-related costs recorded in Account 930.2.

As part of the examination of Account 930.2, audit staff determined that in 2010 and 2011 PPL Electric recorded $3,874,758 and $696,010, respectively, of MGP environmental remediation costs in this account and subsequently included these amounts in formula rate determinations. In addition, audit staff noted that PPL Electric recorded these MGP environmental obligations in Account 930.2 for years prior to the audit period. PPL Electric represented to audit staff that these amounts were related to its former MGPs, which include Brodhead Creek, Columbia Gas Plant, Milton Gas Plant, Mt. Joy Gas Plant, and Shamokin Gas Plant. These MGPs were owned by Pennsylvania Power and Light Company, to which PPL Electric is the successor. However, these MGPs are no longer reflected on PPL Electric's books. The MGPs were not used in PPL Electric's wholesale transmission operations. Rather, they were historically used to produce a low Btu gas that was distributed to the Pennsylvania Power and Light Company's retail gas utility customers during the earlier years of the company's operations, when it was both a natural gas and electric utility.

PPL Electric should amend its accounting policy for MGP environmental obligations to record such contingencies by debiting the appropriate nonoperating expense account and crediting Account 242 or Account 253, as appropriate. PPL Electric should also refrain from including these costs in formula rate determinations, since these costs were not associated with providing service to wholesale transmission customers.

Recommendations

We recommend that:

13. PPL Electric should amend its accounting policies to ensure manufactured gas plant remediation expenses are accounted for consistent with the Commission's accounting regulations.

14. PPL Electric should refrain from including manufactured gas plant remediation expenses in the formula rate determinations, since such costs were not incurred in providing service to wholesale transmission customers.

15. PPL Electric should determine the amount of manufactured gas plant remediation expenses recovered through its formula rate.

16. For each year affected, PPL Electric should refund the manufactured gas plant remediation expense amounts improperly included and recovered through the formula rate, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

17. PPL Electric should file a refund report with the Commission that reflects amounts refunded to its wholesale transmission customers.

4. Asset Retirement Obligation

KU and LG&E neither sought nor received Commission approval to recover asset retirement obligation costs in their transmission formula rate.

Pertinent Guidance

Order No. 631 states:

> However, public utilities, licensees, and natural gas companies with formula rate tariffs must not include any cost components related to asset retirement obligations in their formula rate billing tariffs for automatic recovery in their billing determinations without obtaining Commission approval. [12]

Order No. 631 goes on to say:

> The Commission finds that the issue of whether, and to what extent, a particular asset retirement cost must be recovered through jurisdictional rates should be addressed on a case-by-case basis in the individual rate change filed by public utilities, licensees, and natural gas companies. To ensure that all rate base amounts related to asset retirement obligations can be identified and excluded from the rate base calculation in a rate change filing, the Commission adds sections 35.18 and 154.315 to its rate change filing requirements. These new regulations require that public utilities, licensees, and natural gas companies who have recorded an asset retirement obligation on their books in accordance with this rule must, as part of any initial rate filing or general rate change filing, provide a schedule identifying all cost components related to the asset retirement obligation that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. In addition, the regulations require that all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment. If the public utility, licensee, or natural gas company is seeking recovery of an asset retirement obligation in rates, it must also provide a detailed study supporting the amounts proposed to be collected in rates. If the public utility, licensee, or natural gas company is not seeking

[12] *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, 103 FERC ¶ 61,021, at P 60 (2003).

> recovery of the asset retirement obligation in rates, then it must remove all asset retirement obligation related cost components from its cost of service.[13]

Section 35.18 of the Commission's regulations specifically states:

> (a) A public utility that files a rate schedule, tariff or service agreement under section 35.12 or section 35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.
>
> (b) A public utility seeking to recover nonrate base costs related to asset retirement costs in rates must provide, with its filing under section 35.12 or section 35.13, a detailed study supporting the amounts proposed to be collected in rates.
>
> (c) A public utility that has recorded asset retirement obligations on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.[14]

18 C.F.R. pt. 101, Account 182.3, Other Regulatory Assets, states, in part:

> When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, account 407.4, Regulatory credits, shall be credited.

[13] *Id.* P 62.

[14] 18 C.F.R. section 35.18 (2012).

Background

KU and LG&E recorded liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with a separate asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased to reflect changes in the obligation due to the passage of time through the recognition of accretion expense.

General Instruction 25 of part 101 of the USofA defines an asset retirement obligation (ARO) as:

> A liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.[15]

KU and LG&E initially recorded the ARO by debiting Account 101, Electric Plant in Service, and crediting Account 230, Asset Retirement Obligation. These AROs were for obligations associated with ash ponds, chemical storage, asbestos, coal storage, environmental ponds, and other operational matters.

To record the depreciation on the ARO assets, KU and LG&E debited Account 403.1, Depreciation Expense for Asset Retirement Costs, and credited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. This depreciation is calculated on a straight line basis over a life dictated by the settlement date of the ARO liability.

For accretion expense, KU and LG&E debited Account 411.10, Accretion Expense, and credited Account 230. The accretion expense recognizes the increase in the cost of removing an asset over its useful life.

Lastly, to defer the total depreciation on ARO costs and accretion on ARO liabilities, KU and LG&E debited Account 182.3, Other Regulatory Assets, and credited Account 407.4, Regulatory Credits. Account instructions to Account 182.3 would require KU and LG&E to credit Account 407.4, Regulatory Credits, when "specific identification of the particular source of a regulatory asset cannot be made." However, in this case, the particular source of the regulatory asset can be specifically identified as the depreciation initially recorded in Account 403.1 and the accretion initially recorded in Account 411.10. Therefore, KU and LG&E should have credited Accounts 403.1 and

[15] 18 C.F.R. pt. 101, General Instruction 25.

411.10 rather than Account 407.4. Audit staff understands that amounts deferred in Account 182.3 may have been included in depreciation expense recorded in Account 403.1 and previously collected from wholesale power and transmission customers. Due to these being previously collected, KU and LG&E overstated the regulatory asset recorded in Account 182.3. However, audit staff will not require KU and LG&E to reduce the regulatory asset to the extent KU and LG&E make refunds for the amounts previously collected.

Although KU and LG&E recorded the ARO assets and liability in Accounts 101 and 230, respectively, it included in rate base only the amounts recorded in Account 101 resulting in an increase in rate base. By not decreasing rate base by the amount recorded in Account 230, KU and LG&E overstated amounts included in rate base. Also, KU and LG&E flowed through the effects of the depreciation of the ARO assets recorded in Accounts 403.1 and 108 in the formula rate.

It is audit staff's understanding that ARO costs were included in LG&E and KU's formula rate calculation since inception of the formula rate. Based on Commission requirements, audit staff believes no aspect of the ARO should have been included in formula rate billings to wholesale power and transmission customers, absent KU and LG&E seeking approval from the Commission to include ARO amounts in formula rate determinations. This would have afforded the Commission the opportunity to request further information regarding KU and LG&E's accounting and the impacts of including ARO amounts to determine the annual revenue requirement. KU and LG&E should refund amounts previously collected from wholesale power and transmission customers related to their ARO obligations.

Recommendation

We recommend that:

18. LG&E and KU should submit a filing with the Commission under FPA section 205 to address their recovery of asset retirement obligation costs.

19. LG&E and KU should calculate the rate impact of recovering these ARO costs in the formula rate, and provide these calculations to the Division of Audits and Accounting.

20. For each year affected since the inception of their stand-alone formula rate, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to recovering asset retirement obligation costs, calculated with interest under section 35.19a of the Commission's regulations.

5. Virginia Distribution Utility Plant Costs

KU did not remove all amounts from its formula rate calculations associated with its Virginia distribution utility plant facilities, as required by the Commission.

Pertinent Guidance

The March 17, 2006 Commission order accepting KU and LG&E's attachment O formula rate stated:

> We accept the attachment O rate formula for use in Applicants' stand-alone OATT, subject to revision. We agree with Applicants that the proposed rate formula represents an appropriate rate methodology for inclusion in Applicants' stand-alone OATT. However, Applicants must exclude the cost of certain facilities in Virginia that the Commission has found to serve a distribution function and not a transmission function. [16]

Note M of Attachment O requires KU to remove transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until FERC Form No. 1 balances are adjusted to reflect application of seven-factor test).[17]

[16] *Louisville Gas and Electric Company, et al.*, 114 FERC ¶ 61,282 at P198, (2006) (Citing *Louisville Gas & Electric Co*., 109 FERC ¶ 61,330 at P 8-9 (2004) (order affirming Presiding Judge's finding that certain facilities in Virginia that perform a distribution function must be excluded from the formula rates used in an interconnection agreement and transmission service agreement between Applicants and East Kentucky Coop.), *order denying reh'g*, 111 FERC ¶ 61,323 at P 50 (2005)).

[17] FERC uses a seven-factor test to determine whether an electric facility is distribution or transmission. FERC will give deference to state commission determinations, but that is limited by the expectation that the state follows the seven-factor test: (1) Local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems; it rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported onto some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographic area; (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) local distribution systems will be of reduced voltage. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,771, 31,981 (1996).

Background

KU's transmission facilities in southwestern Virginia consist of 22 miles of 500-kV lines, 44 miles of 161-kV lines, 8 miles of 138-kV lines, 114 miles of 69-kV lines, and 5 transmission substations.

In a March 2004 initial decision, an administrative law judge determined that these Virginia transmission facilities serve a distribution function and not a transmission function, and, therefore, KU must eliminate the cost of these facilities from the transmission rates it charges.[18] In December 2004, the Commission affirmed the administrative law judge's finding that these Virginia transmission facilities serve a distribution function and not a transmission function and stated that the costs of these facilities must be eliminated from the rates charged.[19] In the March 2006 order that conditionally approved KU's withdrawal from Midwest Independent Transmission System Operator, Inc. (MISO), the Commission again required KU to "exclude the cost of certain facilities in Virginia that the Commission has found to serve a distribution function and not a transmission function."[20]

During a review of the transmission formula rate calculation, audit staff determined that KU did not comply with Note M of Attachment O, which requires KU to remove transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test. KU acknowledged that its Virginia transmission facilities were state-jurisdictional, and KU should have removed the Gross Plant in Service cost of its Virginia transmission facilities and associated depreciation in the calculation of the Transmission Plant Allocator of Attachment O, in conformity with Note M of Attachment O.

Audit staff determined that, by not complying with Note M, KU did not remove certain expenses related to these Virginia distribution plant facilities from formula rate determinations. This includes not only amounts included in the calculation of rate base, return, depreciation, and income taxes that are allocated directly using the transmission plant allocator, but also amounts or expenses, such as accumulated deferred income taxes, operation and maintenance expenses, administrative and general expenses, or taxes other than income taxes that are allocated using other allocators (based on net or gross plant balances, wages and salaries, transmission operation and maintenance expenses,

[18] *Louisville Gas & Electric Co*., 106 FERC ¶ 63,039, at P 64 (2004), *aff'd*. 109 FERC ¶ 61,330 at P 8 (2004), reh'g denied, 111 FERC ¶ 61,323.

[19] *Louisville Gas & Electric Co.*, 109 FERC ¶ 61,330 (2004).

[20] *Louisville Gas & Electric Co*., 114 FERC ¶ 61,282, at P 197 (2006).

etc.) that indirectly incorporate the transmission plant allocator. This resulted in KU erroneously collecting amounts from wholesale power and transmission customers since it did not remove all costs associated with the Virginia distribution plant facilities from formula rate determinations.

Recommendations

We recommend that:

21. LG&E and KU should calculate the rate impact of recovering these costs in their stand-alone formula rate, and provide these calculations to the Division of Audits and Accounting.

22. For each year these Virginia distribution utility costs were included in their stand alone formula rate calculation, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate, calculated with interest under section 35.19a of the Commission's regulations.

6. Accounting for Cost of Removal

KU and LG&E improperly accounted for cost of removal on physical assets with legal asset retirement obligations.

Pertinent Guidance

18 C.F.R. pt. 101, Account 108, Accumulated Provision for Depreciation of Electric Utility plant (Major Only), states, in part:

> A. This account shall be credited with the following:
>
> (1) Amounts charged to account 403, Depreciation expense, or to clearing accounts for current depreciation expense for electric plant in service.
>
> (2) Amounts charged to account 403.1, Depreciation expense for asset retirement costs, for current depreciation expense related to asset retirement costs in electric plant in service in a separate subaccount.

E. The utility is restricted in its use of the accumulated provision of depreciation to the purposes set forth above. It shall not transfer any portion of this account … or make any other use thereof without authorization by the Commission.

Background

Audit staff examined KU and LG&E's cost of removal accounting for physical assets with legal asset retirement obligations, such as ash ponds, landfills, and coal storage facilities. KU and LG&E booked the cost of removal related to these assets by debiting Account 403, Depreciation Expense, and crediting Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. KU and LG&E then reclassified these amounts to a regulatory liability account by debiting Account 108 and crediting Account 254, Other Regulatory Liabilities. Once KU and LG&E retired the asset and settled the ARO, KU and LG&E debited Account 254 and credited Account 108.

While KU and LG&E received state commission guidance from the Kentucky Public Service Commission that approved this accounting treatment, such approval does not dictate how this transaction should be accounted for under the Commission's accounting regulations. Under the Commission's accounting regulations, cost of removal is typically factored in the depreciation rate, and depreciation expense is accounted for in Accounts 403 and 108. According to the instructions to Account 108, amounts recorded herein must not be transferred to any other account absent of approval from the Commission. KU and LG&E did not seek nor receive approval from the Commission to transfer any amounts from Account 108. By transferring amounts initially recorded in Account 108 to Account 254, KU and LG&E did not follow the instructions for Account 108. For rate purposes, Account 108 is typically used to reduce rate base while amounts recorded in Account 254 are typically not used in the formula rate calculations. Since KU and LG&E removed these amounts from Account 108, it erroneously overstated rate base used to determine formula rate billings to transmission customers. Audit staff is aware that this accounting practice was used for years prior to the audit period.

Recommendations

We recommend that:

23. LG&E and KU should provide to the Division of Audits and Accounting correcting entries that show the reversal of amounts from Account 254.

24. For each year these amounts were included in their stand-alone formula rate, LG&E and KU should refund all costs, calculated with interest under section 35.19a of Commission regulations.

25. LG&E and KU should file a refund report with the Commission that reflects amounts refunded to their customers.

7. Merger Costs

PPL's three franchised public utilities (KU, LG&E, and PPL Electric) incorrectly included some transaction-related costs related to PPL's merger with E.ON U.S. in formula rate billings to wholesale power and transmission customers.[21]

Pertinent Guidance

The October 25, 2010 Commission order approving the merger of PPL and E.ON U.S., LLC stated:

> With respect to transaction-related costs, we accept Applicants' commitment to hold transmission and wholesale customers harmless from costs related to the transaction for a period of five years to the extent that such costs exceed savings related to the transaction, which we interpret to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. We also note that, if Applicants seek to recover transaction-related costs in a filing whereby they are proposing a new rate (either a new formula rate or a new stated rate), then that filing must be made in a new section 205 docket as well as in the instant section 203 docket. The Commission will notice such filings for public comment. In such filings, Applicants must: specifically identify the transaction-related costs they are seeking to recover, and (2) demonstrate that those costs are exceeded by the savings produced by the transaction, in addition to any requirements associated with filings made under section 205. Such a hold

[21] KU sells wholesale power to certain municipal utilities under long-term agreements that established cost-based wholesale power rates based on a formula rate. Moreover, PPL Electric, LG&E, and KU provide transmission service at formula rates.

> harmless commitment will protect customers' wholesale power and transmission rates from being adversely affected by the proposed transaction. [22]

Background

On June 28, 2010, PPL filed an application seeking authorization under sections 203(a)(1)(A), 203(a)(1)(B), and 203(a)(2) of the FPA for a proposed transaction in which PPL would acquire all of the issued and outstanding limited liability company interests of E.ON U.S. from E.ON AG's indirect, wholly owned subsidiary, E.ON U.S. Investments Corp. PPL sought to acquire E.ON U.S. for a purchase price of $7.625 billion, comprised of $2.062 billion in cash (subject to adjustment), the repayment of outstanding debt of E.ON U.S., LG&E, and KU estimated at $4.638 billion, and the assumption of $925 million in tax-exempt bonds of LG&E and KU. On October 25, 2010, the Commission issued an order approving the transaction under Docket No. EC10-77-000. [23] Audit staff evaluated PPL and its FPU subsidiaries for compliance with the conditions of this order. Besides reviewing Commission orders and company filings, understanding processes and procedures, and interviewing company staff, audit staff reviewed and tested compliance with the order's various provisions, such as verifying that the transaction did not result in any: (1) transfer of jurisdictional facilities between affiliated entities; (2) any securities issued for the benefit of any affiliated entity or in any new pledge or encumbrance of assets of an affiliated entity; or (3) any new affiliate contracts between affiliated entities. Audit staff also verified that all purchase accounting adjustment amounts were removed from account balances reported in the FERC Form No. 1.

Audit staff also evaluated compliance with the order's hold harmless provision, which required PPL to "hold transmission and wholesale customers harmless from costs related to the transaction for a period of five years to the extent that such costs exceed savings related to the transaction, which we interpret to include all transaction-related costs, not only costs related to consummating the transaction."

PPL properly excluded most of its transaction-related costs from formula rate billings to wholesale power and transmission customers, which included legal fees, consulting expenses, third-party costs, and internal labor costs. PPL had controls and procedures in place to hold harmless wholesale power and transmission customers, such as: payroll and time-reporting controls, communications from appropriate groups on how to charge certain costs, and supervisory review and approval of nonpayroll charges.

[22] *PPL Corporation*, 133 FERC ¶ 61,083, at PP 26-27 (2010).

[23] *Id.* P 1.

However, audit staff identified a small amount of transaction-related costs that flowed through to the formula rate billings.

In our review of transaction-related costs, audit staff determined that PPL's two service companies (PPL Services and LKS) allocated the most transaction-related costs to PPL ($113 million), LG&E & KU Capital ($32 million), and PPL Strategic Development ($1 million). These three entities held $146 million of the approximately $150 million in total transaction-related costs incurred during the audit period. The remaining $4 million of transaction-related costs were allocated to 12 other PPL entities, including PPL's 3 franchised public utilities, KU, LG&E, and PPL Electric, which are in bold in the table below. This table shows transaction costs allocated to each entity:

PPL Entity	Total Transaction Costs
1. PPL Corporation	$113,164,077
2. LG&E and KU Capital	$32,133,630
3. PPL Strategic Development	$1,262,186
4. PPL Global, LLC	$734,575
5. PPL Susquehanna LLC	$573,396
6. PPL Energy Services Holdings, LLC	$301,957
7. PPL Energy Plus, LLC	$298,902
8. PPL Generation LLC	$257,975
9. PPL Brunner Island, LLC	$222,337
10. PPL Montour LLC	$194,040
11. PPL Electric	**$163,329**
12. Louisville Gas & Electric	**$108,981**
13. Kentucky Utilities	**$95,060**
14. PPL Martins Creek, LLC	$58,814
15. PPL University Park, LLC	$24,408
Total	**$149,593,668**

In summary, PPL's three FPUs, KU, LG&E, and PPL Electric, were allocated approximately $367,000 in transaction-related costs, and they included approximately $329,229 of these costs in their wholesale power and transmission formula rate calculations. These costs consisted primarily of legal fees, consulting fees, wages of PPL staff in different departments, office supplies, and general and administrative expenses. These transaction-related costs included costs that were incurred before PPL filed its merger application with the Commission, during the transaction, and after the transaction was consummated. The Merger Order defines costs related to the transaction as "all transaction-related costs, not only costs related to consummating the transaction." The Merger Order also states, "If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket." PPL made no such filing to seek recovery for these costs.

Recommendations

We recommend that:

26. PPL Electric, LG&E, and KU should strengthen existing procedures so that no transaction-related costs flow through an FPU's formula rates.

27. PPL Electric, LG&E, and KU should calculate the rate impact of recovering transaction-related costs in their respective formula rates, and provide these calculations to the Division of Audits and Accounting.

28. PPL Electric, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to the incorrect allocation of transaction-related costs, calculated with interest in accordance to the Commission-approved formula rate protocols for PPL Electric and under section 35.19a of the Commission's regulations for LG&E and KU.

8. Allowance for Funds Used During Construction

KU's method of computing AFUDC on CWIP was deficient by compounding AFUDC monthly instead of semi-annually, including unrealized losses in its common equity balance used to calculate AFUDC, and using an incorrect balance for the common equity component.

Pertinent Guidance

AFUDC allows a company to recover its debt and equity costs used for funding construction. In Federal Power Commission's (FPC) Order No. 561, the Commission's predecessor agency, the FPC established a uniform formula for determining maximum rates to use for computing AFUDC.[24] The order states:

> The balances of long-term debt, preferred stock, and common equity for use in the formula for the current year will be the balances in such accounts at the end of the prior year; the cost rates for long-term debt and preferred stock will be the effective weighted average cost of such capital. The average short-term debt balances and related cost and the average construction work in progress balance will be estimated for the current year. We shall require, however, that public utilities and natural gas companies monitor their actual experience and adjust to actual at year-end if a significant deviation from the estimate should occur. For this purpose we shall consider a significant deviation to exist if the gross AFUDC rate exceeds by more than one-quarter of a percentage point (25 basis points) the rate that is derived from the formula by use of actual 13 monthly balances of construction work in progress and the actual weighted average cost and balances for short-term debt outstanding during the year.

On frequency of compounding of the AFUDC base, Order No. 561 states:

> We believe that a monthly compounding of AFUDC may result in excessive amounts capitalized since cash outlays for interest and dividends are not normally made on a monthly basis. We shall

[24] *Order Adopting Amendment to Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies*, Order No. 561, 57 FPC 608 (1977), *Order On Reh'g and Clarification*, Order 561-A, 59 FPC 1340 (1977), *further clarified*, 2 FERC ¶ 61,050 (1978).

> therefore permit compounding but no more frequently than semiannually.

18 C.F.R. pt. 101, Electric Plant Instruction 3 (17), Allowance for Funds Used During Construction, states in part:

> (a) Includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds.
>
> (b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year … the short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

18 C.F.R. pt. 101, General Instruction 23 (C), Accounting for Other Comprehensive Income, states:

> (c) When it is probable that an item of other comprehensive income will be included in the development of cost-of-service rates in subsequent periods, that amount of unrealized losses or gains will be recorded in Accounts 182.3 or 254 as appropriate.

Background

AFUDC includes the net cost for the period borrowed funds were used for construction and a reasonable rate on other funds. KU recorded the balances below in Account 419.1, Allowance for Other Funds Used During Construction, and Account 432, Allowance for Borrowed Funds Used During Construction – Credit, during the audit period:

Year	Account 419.1	Account 432
2010	$521,152	$968,597
2011	$42,662	$12,955

Audit staff evaluated KU's AFUDC base and rate calculations, and the application of these calculations, to determine the accrual of AFUDC on CWIP for select construction projects. This evaluation identified several deficiencies with KU's AFUDC calculation methodology.

1. *AFUDC Compounded Monthly* – KU improperly compounded its AFUDC on a monthly basis. The Commission allows for compounding of AFUDC no more frequently than semi-annually.

2. *Unrealized Losses* – KU incorrectly included unrealized losses from Account 219, Accumulated Other Comprehensive Income (AOCI), in the common equity component of the AFUDC rate calculation. Specifically, KU recorded unrealized losses for its 20 percent ownership of Electric Energy, Inc.'s AOCI, which consisted of the unfunded portion of its pension and postretirement obligations. KU recorded Account 219 balances of ($2,854) and ($467,077) in 2010 and 2011, respectively. Accounting treatment for these unrealized losses was a debit to Account 219 and a credit to Account 123, Investment in Associated Companies (Major Only). Since these losses are unrealized and not used in determining KU's retained earnings, these amounts should not impact the amount of retained earnings used to calculate the AFUDC rate. Therefore, Account 219 should not be in the common equity component of the AFUDC calculation. However, it is appropriate for KU to include losses in determining the AFUDC rate once these amounts are realized, and enter retained earnings.

3. *Common Equity Balance* – KU input the wrong balance as the common equity component to its AFUDC calculation. For its 2010 AFUDC calculation, KU input the long-term debt amount of $1,648,779,405, instead of the common equity amount of $1,951,966,344, as found in the 2009 KU FERC Form No. 1 on line 16(c).

During the 2010 and 2011 years, KU accrued an aggregate amount of $1,545,366 in total AFUDC. Due to the above errors, this amount understated the correct actual amount, which was $1,550,647. The errors included overstatement effects of $290 and $305, due to the monthly compounding and inclusion of AOCI balance errors, respectively, offset by an understatement effect of $5,876 due to the common equity input error.

Recommendations

We recommend that:

29. KU should revise and implement procedures going forward to ensure its AFUDC base and rate calculation is consistent with Electric Plant Instruction 3(17) and other applicable Commission requirements.

9. Formula Rate Line References

KU and LG&E's formula rate Attachment O included multiple inaccurate line references.

Pertinent Guidance

Attachment O (Transmission Formula Rate) of KU and LG&E's OATT required formula rate inputs derived from FERC Form No. 1 amounts.

Background

During our review, audit staff determined that KU and LG&E's formula rate Attachment O included multiple inaccurate line references. Specifically, audit staff identified these incorrect line references:

Formula Rate Component	Att. O Reference	FERC Form No. 1 Line Item
Gross Plant in Service - Production	206.46g	205.46g
Gross Plant in Service - Transmission	206.58g	207.58g
Gross Plant in Service - Distribution	206.75g	207.75g
Gross Plant in Service - General & Intangible	206.5g and 206.90g	205.5g and 207.99g
Accumulated Depreciation - General & Intangible	219.27c	219.28c and 200.21c
Land Held For Future Use	214xd	Must specify line number
Materials & Supplies	227.8c and 227.15c	227.8c and 227.16c
O&M - Transmission	321.100b	321.112
O&M - Account 565	321.88b	321.96b
Depreciation Expense - General	336.10f	336.1f and 336.10f
Payroll Taxes	263i	Must specify line number
Highway and Vehicle Taxes	263i	Must specify line number
Property Taxes	263i	Must specify line number
Gross Receipts Taxes	263i	Must specify line number
Other Taxes	263i	Must specify line number
Wages & Salaries - Production	354.18b	354.20b
Wages & Salaries - Transmission	354.19b	354.21b
Wages & Salaries - Distribution	354.20b	354.23b
Wages & Salaries - Other	354.21, 22, 23b	354.24, 25, 27b
Proprietary Capital	112.15d	112.16d
Long term debt	112.18c-21c	112.18c-23c
Preferred Stock	112.3d	112.3c
Sales for Resale	311xh	Must specify page/line/column

Also, audit staff determined that KU and LG&E can improve the transparency of their formula rate calculations by better presenting all manual adjustments and purchase accounting adjustments that impact balances reported within Attachment O.

Recommendations

We recommend that:

30. LG&E and KU should develop and implement controls to ensure accurate and complete line references.

31. LG&E and KU should submit a filing with the Commission under FPA section 205 to address the incorrect formula rate line references.

10. FERC Form No. 60 Reporting

FERC Form No. 60 filings that PPL Services and LKS made contained several reporting errors relating to account misclassifications, supporting schedule discrepancies, and the reporting of convenience payments.

Pertinent Guidance

In 2006, centralized service companies became subject to the requirements of PUHCA 2005, which are incorporated into the Commission regulations in 18 C.F.R. pts. 366-369. The FERC Form No. 60 has specific reporting instructions for preparation of individual schedules and pages of the report. Regulations applicable to FERC Form No. 60 reporting by centralized service companies are:

18 C.F.R. section 366.23(a)(1), FERC Form No. 60, annual reports of centralized service companies, states, in part, "Every report must be submitted on the FERC Form No. 60 then in effect and must be prepared in accordance with the instructions incorporated into that form."

18 C.F.R. section 369(2)(ii), FERC Form No. 60, annual report of centralized service company, states in part, "The annual report in effect must be filed with the Commission as prescribed in Section 385.2011 of this chapter and as indicated in the General Instructions set out in the form, and must be properly completed and verified."

Background

Audit staff analyzed the FERC Form No. 60 filings made by PPL's two service companies – PPL Services and LKS. This analysis identified these reporting errors:

<u>900 Series Account Misclassifications</u>

PPL Services misclassified amounts reported on its 2010 FERC Form No. 60 for Accounts 920, Administrative and General Salaries, 921, Office Supplies and Expenses, and 923, Outside Services Employed. Specifically, PPL Services over-reported Account 920 by approximately $7 million, over-reported Account 921 by approximately $5 million, and under-reported Account 923 by approximately $12 million.

<u>Accounts 457.1, Regional Transmission Service Revenues, and 457.2, Miscellaneous Revenues, Reporting</u>

In its 2010 FERC Form No. 60, which reported only November and December 2010, PPL Services reported total billings of $67,368,843 on Schedule XVII – Analysis of Billing-Associate Companies. PPL Services then provided supporting documentation for total billings for November and December 2010 that totaled $68,300,671. This resulted in a variance of $931,828.

LKS identified adjustments in February 2010 for $138,642.20 and September 2010 for $1,426,588.45 in Account 457.1. For both months, both revenue and expenses were understated.

These errors occurred for various reasons, including administrative oversight, limited review procedures, and the absence of appropriate verification procedures.

<u>Convenience Payments</u>

Service companies report convenience payments on Schedule V of its FERC Form No. 60. Specifically, instruction 2 of Schedule V states:

> *If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.*

Audit staff reviewed convenience payment data from LKS. During this review, audit staff learned that some convenience payments, amounting to $252,448, were reflected on the 2010 income statement. These payments were recorded in Account 923, and were identified as having convenience payment expenditure types in error. Also, additional expenses, amounting to $1,570, were reflected as 2010 convenience payments and should not have been. Convenience payments should be charged only to balance sheet accounts and not income statement accounts. Therefore, these amounts were recorded in error. These errors caused no financial impact as they were included in both revenue and expense on the service company's income statement.

These errors were due to human error involving misclassification and improper recording of expenses. To address them, LKS developed and implemented a procedure to determine if convenience payments had been modified to use a more detailed review of transactions to be disclosed.

Recommendations

We recommend that:

32. LKS and PPL Services should develop and implement procedures to ensure proper account classification, consistent reporting, and completion of all supporting schedules of the FERC Form No. 60. As part of these procedures, incorporate an annual review to ensure the FERC Form No. 60 filed with the Commission is complete and accurate.

33. LKS and PPL Services should refile 2010 FERC Form No. 60, correcting all reporting errors within 90 days after this report is issued.

V. Other Matters

Formula Rate Recovery of Intangible Plant

KU and LG&E's formula rate under Attachment O of its joint OATT included templates for calculating rate base and cost-of-service components used to determine transmission formula rate billings. As relevant here, the Attachment O formula rate included a FERC Form No. 1 line reference for gross intangible plant in service. However, the Attachment O formula rate did not include a FERC Form No. 1 line reference for accumulated amortization related to intangible plant. Also, the Attachment O formula rate did not include a FERC Form No. 1 line reference for amortization expense of intangible plant. When KU and LG&E withdrew from MISO and began recovering their transmission revenue requirement under their joint OATT in March 2006, they adopted a formula rate that is substantially the same formula rate template in Attachment O to the MISO OATT, and carried over the same omissions related to intangible plant.

In October 2011, MISO and its transmission owners filed revisions to portions of the Attachment O formula rate, under FPA section 205**,** to clarify inclusion of intangible plant in the calculation of Attachment O revenue requirements under Docket No. ER12-297-000. The filing parties proposed to clarify the inclusion of intangible plant by adding the appropriate FERC Form No. 1 reference to intangible plant for the line item that contains accumulated depreciation on general and intangible plant. The filing parties also proposed to add the language "and Amortization" to the column heading for "Depreciation Expense" and add the language "and Intangible" to the line item for "General" depreciation and amortization expense. Finally, the filing parties proposed to add the appropriate FERC Form No. 1 reference for amortization expense of intangible plant. On December 21, 2011, the Commission accepted MISO's submittal for filing.

During audit fieldwork, audit staff pointed out that KU and LG&E's formula rate under its joint OATT continues to have omissions related to intangible plant that were identified and corrected in Docket No. ER12-297-000. Since KU and LG&E now recover their cost of service based on a formula rate substantially the same as the MISO formula rate, they should have made a filing with the Commission under FPA section 205, similar to what MISO and its transmission owners did in ER12-297-000, to address the proper recovery of intangible plant.

Specifically, in calculating the revenue requirement for the transmission formula rate, KU and LG&E included intangible plant assets recorded in Accounts 301, Organization, 302, Franchise and Consents, and 303, Miscellaneous Intangible Plant, as components of its rate base. However, KU and LG&E did not reduce any of these amounts by any related corresponding amortization recorded in Account 111, Accumulated Provision for Amortization of Electric Plant.

Recommendation

We recommend that:

LG&E and KU submit a filing with the Commission under FPA section 205 to adopt the revisions for intangible plant MISO proposed in Docket No. ER12-297-000 and incorporate them into KU and LG&E's formula rate template under their joint OATT.

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September 26, 2014

Bryan K. Craig
Director and Chief Accountant, Division of Audits and Accounting
Federal Energy Regulatory Commission
888 First Street N.E. - Room 5K-13
Washington, DC 20425

Re: PPL Corporation, Docket No. FA12-12-000
Comments on Draft Audit Report

Dear Mr. Craig:

PPL Corporation ("PPL") appreciates this opportunity to comment on the September 11, 2014 Draft Audit Report provided to PPL by the Division of Audits and Accounting of the Office of Enforcement of the Federal Energy Regulatory Commission ("DAA") relating to an audit conducted in the above-referenced docket (the "Draft Audit Report"). PPL agrees with the findings and accepts the recommendations contained in the Draft Audit Report.

In many cases, PPL already has completed implementation or begun implementation of corrective measures related to the audit findings. Attachment A to this letter explains the corrective actions taken or planned, and provides actual or target completion dates for these actions.

PPL wishes to thank DAA personnel involved in the audit for their professionalism and courtesy.

Sincerely,

Vincent Sorgi

Attachment

Attachment A

I. Draft Audit Report Section IV. Findings and Recommendation

1. ***Long-Term Investment in Subsidiary***

Recommendation 1 - PPL Electric should provide notice of its material accounting changes to its wholesale transmission customers as required by section III.B of Attachment H-8H, Formula Rate Implementation Protocols, of its Open Access Transmission Tariff.

Corrective Action: On May 15, 2014, PPL Electric filed its 2014 Annual Update with the Federal Energy Regulatory Commission ("Commission") in Docket No. ER09-1148 pursuant to the Formula Rate Implementation Protocols of its Open Access Transmission Tariff. The Commission publicly posted the filing on its eLibrary system the same day. Therein, PPL Electric explained that it changed its method of accounting for the activities of its subsidiary PPL Receivables Corporation from the consolidated method of accounting to the equity method of accounting in accordance with the Commission's regulations and that the changes affected PPL Electric's 2009 through 2013 Rate Years, given that the formula rate was first implemented on November 1, 2008. PPL Electric served the 2014 Annual Update on all parties to the docket on May 15, 2014, and provided a copy to its Regional Transmission Organization, PJM Interconnection, L.L.C. ("PJM") for posting on the PJM website. This action is completed.

Recommendation 2 - PPL Electric should implement procedures to ensure that it follows the equity method of accounting for all investments in subsidiaries and ensure no deviation between accounting practices and Commission accounting regulations.

Corrective Action 1: By November 30, 2014, PPL Electric will finalize its policy related to the differences in FERC and Securities and Exchange Commission ("SEC") reporting. Included in this policy will be a discussion of the accounting for investments in subsidiaries using the equity method of accounting and recording those investments in Account 123.1, Investment in Subsidiary Companies, for FERC reporting purposes, consistent with the FERC's accounting guidelines.

Corrective Action 2: In December 2013, PPL Electric implemented a new methodology that involves reviewing and cataloging electric industry-wide FERC Audit Report findings to ensure that PPL Electric appropriately reflects the accounting for similar transactions identified in such audit findings. The associated database is updated quarterly.

Corrective Action 3: On November 8, 2013, PPL Corporation modified its Journal Entry policy and procedures to specifically state that the impact on rate making mechanisms be considered for all journal entries affecting the domestic regulated utilities within the PPL family of companies.

Corrective Action 4: PPL Electric, together with PPL Services, will establish enhanced senior management-level procedures for on-going communication and oversight of company analysis and implementation of FERC developments related to accounting procedures and transmission formula rate calculations. This is expected to be completed within 90 days of the issuance of a final audit report.

Recommendation 3 - PPL Electric should adopt controls that will ensure all costs related to PPL Receivables' operating activities are excluded from all components in PPL Electric's formula rate calculation.

Corrective Action 1: By November 30, 2014, PPL Electric will finalize its policy related to the differences in FERC and SEC reporting. Included in this policy will be a discussion of the accounting for investments in subsidiaries using the equity method of accounting and recording those investments in Account 123.1, Investment in Subsidiary Companies, for FERC reporting purposes, consistent with the FERC's accounting guidelines.

Corrective Action 2: PPL Electric has modified its reporting of PPL Receivables in FERC Form 1 to use the equity method of accounting. PPL Electric utilizes the FERC Form 1 as the basis for its formula rate inputs. By reporting PPL Receivables using the equity method, PPL Electric will no longer include PPL Receivables' operating activities in the formula rate calculation.

Recommendation 4 - PPL Electric should refund all costs incorrectly included in and recovered through the formula rate since its inception, with interest, calculated in accordance with the formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

Corrective Action: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the costs to properly account for PPL Receivables Corporation using the equity versus consolidated method of accounting recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

Recommendation 5 - PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

Corrective Action: PPL Electric expects to file a refund report within 90 days of the issuance of a final audit report.

2. ***Tax Overpayments***

Recommendation 6 - PPL Electric should reclassify federal and state income taxes recorded in Account 165, Prepayments, applicable to those years in which PPL Electric chose to receive a refund of those amounts to Account 146, Accounts Receivable from Associated Companies or Account 143, Other Accounts Receivable, as appropriate.

Corrective Action: PPL Electric reclassified federal and state income tax overpayments to the appropriate receivable accounts for the 2011 and 2012 balance sheets and for supporting pages of the 2012 FERC Form I Restatement filed on October 29, 2013. PPL Electric also reclassified federal and state income tax overpayments to the appropriate receivable accounts for rate years 2009-2013 and refunded the reduction in the revenue requirement, with interest, that resulted from including overpayments as receivables rather than prepayments as explained in the 2014 Annual Update filed with the Commission in May 15, 2014.

Recommendation 7 - PPL Electric should submit correcting entries to the Division of Audits and Accounting within 30 days of this report.

Corrective Action: PPL Electric will submit correcting entries to DAA within 30 days of the date of the issuance of the final audit report.

Recommendation 8 - PPL Electric should revise procedures to ensure its income tax transactions recorded to Account 165 represent actual prepayments.

Corrective Action 1: PPL Electric revised procedural documentation to explain the accounting of federal and state income tax overpayments on November 25, 2013. PPL Electric also implemented an automated process that will no longer reclassify federal and state income tax overpayments to Account 165, which began with the December 31, 2013 accounting close.

Corrective Action 2: In addition, as this is an area where FERC accounting differs from SEC accounting, the policy relating to differences in FERC and SEC reporting that is referenced in Corrective Action 1 of Recommendation 2 will make reference to this issue. That policy will be completed by November 30, 2014.

Recommendation 9 - PPL Electric should revise procedures to appropriately determine its tax accrual amount.

Corrective Action: PPL Electric has revised its procedures to properly reclassify income tax overpayments, determined through its accrual and payment process, recorded in Account 236 to either Account 143 or Account 146. See corrective action to Recommendation 8.

Recommendation 10 - PPL Electric should record the necessary correcting entries as of December 31 to reflect the proper accounting for Federal and state estimated tax overpayment.

Corrective Action: PPL Electric has completed this as part of the corrective actions discussed in response to Recommendation 6 above.

Recommendation 11 - For each year these amounts were included in the formula rate calculations, PPL Electric should refund all costs incorrectly included in and recovered through the formula rate, with interest, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

Corrective Action: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the costs incorrectly included in and recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

Recommendation 12 - PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

Corrective Action: PPL Electric expects to file a refund report within 90 days of the issuance of a final audit report.

3. *Manufactured Gas Plant Obligations*

Recommendation 13 - PPL Electric should amend its accounting policies to ensure manufactured gas plant remediation expenses are accounted for consistent with the Commission's accounting regulations.

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Corrective Action: As referenced in Corrective Action 1 of Recommendation 2, PPL Electric will finalize its policy related to the differences in FERC and SEC reporting by November 30, 2014. Included in this policy is a discussion of the recording of manufactured gas site remediation expenses to Account 426.5, Other Deductions, for FERC reporting purposes, consistent with the FERC's accounting guidelines.

Recommendation 14 - PPL Electric should refrain from including manufactured gas plant remediation expenses in the formula rate determinations, since such costs were not incurred in providing service to wholesale transmission customers.

Corrective Action: PPL Electric provided notice of its accounting change relating to Manufactured Gas Plant costs in its 2014 Annual Update filed with the Commission on May 15, 2014 and will refrain on an ongoing basis from including these costs in its formula rate determinations based on the Division of Audits and Accounting's view that such costs were not incurred in providing service to wholesale transmission customers.

Recommendation 15 - PPL Electric should determine the amount of manufactured gas plant remediation expenses recovered through its formula rate.

Corrective Action: In September 2014, PPL Electric provided to DAA as Attachment 19 the amount of MGP environmental remediation expenses recovered through PPL Electric's transmission formula rate.

Recommendation 16 - For each year affected, PPL Electric should refund the manufactured gas plant remediation expense amounts improperly included and recovered through the formula rate, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

Corrective Action: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the manufactured gas plant remediation expenses improperly included in and recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

Recommendation 17 - PPL Electric should file a refund report with the Commission that reflects amounts refunded to its wholesale transmission customers.

Corrective Action: PPL Electric expects to file a refund report within 90 days of the issuance of a final audit report.

4. *Asset Retirement Obligation*

Recommendation 18 - LG&E and KU should submit a filing with the Commission under FPA section 205 to address their recovery of asset retirement obligation costs.

Corrective Action: LG&E and KU anticipate that they will submit the recommended FPA Section 205 filing relating to the recovery of asset retirement obligations within 90 days of the issuance of a final audit report.

Recommendation 19 - LG&E and KU should calculate the rate impact of recovering these ARO costs in the formula rate, and provide these calculations to the Division of Audits and Accounting.

Corrective Action: In September 2014, LG&E and KU provided estimated rate impact calculations (interest through June 2014) regarding the consolidated anticipated audit findings, including ARO costs, and certain rate under-billings to the Division of Audits and Accounting. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations, including ARO costs, (through a then-current date) within 60 days following issuance of a final audit report. Thereafter, LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing rate impacts for any final or remaining period of ARO cost recovery within 60 days following effectiveness of new rates pursuant to the FPA section 205 proceeding.

Recommendation 20 - For each year affected since the inception of their stand-alone formula rate, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to recovering asset retirement obligation costs, calculated with interest under § 35.19a of the Commission's regulations.

Corrective Action: LG&E and KU will refund or credit to ratepayers amounts inappropriately recovered through the transmission formula rate during such period due to recovering asset retirement obligation costs with interest, and anticipate that they will do so within 30 days of each applicable final Commission order accepting the respective refund reports filed in response to Recommendation 19.

5. *Virginia Distribution Utility Plant Costs*

Recommendation 21 - LG&E and KU should calculate the rate impact of recovering these costs in their stand-alone formula rate, and provide these calculations to the Division of Audits and Accounting.

Corrective Action: In September 2014, LG&E and KU provided estimated rate impact calculations (with interest through June 2014) regarding the consolidated anticipated audit findings, including Virginia distribution plant costs, and certain rate under-billings to the Division of Audits and Accounting. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations, including Virginia distribution plant costs, (through a then-current date) within 60 days following issuance of a final audit report.

Recommendation 22 - For each year these Virginia distribution utility costs were included in their stand alone formula rate calculation, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate, calculated with interest under § 35.19a of the Commission's regulations.

Corrective Action: In connection with LG&E and KU's 2012 Annual Update for rates effective in the 2012 rate year which began on June 1, 2013 and ended on May 31, 2014, LG&E and KU corrected the inputs for Virginia plant so that costs associated with Virginia distribution utility plant no longer would flow through the formula rate. LG&E and KU will refund or credit to ratepayers amounts recovered through the transmission formula rate during such period associated with Virginia plant distribution costs with interest and anticipate that they will do so within 30 days of each applicable final Commission order accepting the refund report filed in response to Recommendation 21.

6. *Accounting for Cost of Removal*

Recommendation 23 - LG&E and KU should provide to the Division of Audits and Accounting correcting entries that show the reversal of amounts from Account 254.

Corrective Action: As part of the August 2013 accounting close, LG&E and KU corrected their accounting entries for cost of removal. Effective with

LG&E and KU's 2013 Annual Update for rates effective in the 2013 rate year which began on June 1, 2014 and ends on May 31, 2015, LG&E and KU's formula rate no longer included rate impacts from such cost of removal accounting. LG&E and KU will file such correcting entries showing the reversal of amounts from Account 254 within 30 days of the issuance of the final audit report.

Recommendation 24 - For each year these amounts were included in their stand-alone formula rate, LG&E and KU should refund all costs, calculated with interest under section 35.19a of Commission regulations.

Corrective Action: LG&E and KU will refund or credit to ratepayers amounts recovered through the transmission formula rate during such period due to cost of removal with interest and anticipate that they will do so within 30 days of each applicable final Commission order accepting the refund report filed in response to Recommendation 25.

Recommendation 25 - LG&E and KU should file a refund report with the Commission that reflects amounts refunded to their customers.

Corrective Action: In September 2014, LG&E and KU provided estimated rate impact calculations (interest through June 2014) regarding the consolidated anticipated audit findings, including cost of removal, and certain rate under-billings to the Division of Audits and Accounting. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations including cost of removal (through a then-current date) within 60 days following issuance of a final audit report.

7. ***Merger Costs***

Recommendation 26 - PPL Electric, LG&E and KU should strengthen existing procedures so that no transaction-related costs flow through an FPU's formula rates.

Corrective Action 1: PPL Corporation made organizational changes in 2011 to create PPL Strategic Development, LLC for the Strategic Development group, the group that coordinates merger and acquisition ("M&A") activities and bears the costs of these activities. This organizational change has made it easier to direct M&A charges to the proper business unit and thereby exclude them from the regulated entities.

Corrective Action 2: PPL Services has improved communications among the Strategic Development group, Office of General Counsel, the Financial

Department and other appropriate groups within PPL Corporation in an effort to establish proper accounting for M&A projects at the onset of such projects by:

a) Reviewing the FERC audit with budget coordinators and reemphasizing the need for stronger controls and accurate accounting for costs associated with Strategic Development acquisition and divesture activities. (completed December 2012).
b) Drafting and reviewing with budget coordinators the proposed Accounting Policy and Procedures for Costs Associated with Acquisitions and Divestures. (completed April 2014).
c) Issuing an email communication to budget coordinators instructing them how to charge transaction and transition costs related to the spinoff of PPL Corporation Supply Segment. (completed June 2014).
d) Conducting meetings with key individuals for the purpose of discussing and reviewing issues related to proper charging of PPL Corporation Supply Segment spinoff costs. (completed July and August, 2014).
e) Issuing the Accounting Policy and Procedures for Costs Associated with Acquisitions and Divestures and communicating said issuance to all budget coordinators. (completed August 2014).
f) Developing and issuing a message to all PPL Corporation supervisors to emphasize the importance of properly capturing all costs related to the spinoff of PPL Corporation Supply Segment. (completed September 2014).

Corrective Action 3: As of August 2014, PPL Services' Financial and Accounting Departments developed an accounting policy/procedure related to M&A activities and included it with other accounting policies and procedures on the Controller's Department Accounting Policies and Procedures intranet web site.

Corrective Action 4: PPL Services will include a summary of the M&A accounting policy in the Cost Allocation Manual during the next update by December 31, 2014.

Corrective Action 5: Commencing with LG&E and KU's 2013 Annual Update for rates effective in the 2013 rate year which began on June 1, 2014 and ends on May 31, 2015, LG&E and KU no longer included rate impacts from such transaction-related costs.

Corrective Action 6: During September 2013, LG&E and KU modified their Regulatory Compliance accounting policy to provide additional guidance on merger costs. Examples of merger transaction and transition costs were included in this accounting policy.

Corrective Action 7: During September 2013, LG&E and KU updated its "Merger Transaction and Transition Cost" accounting treatment guidance on the Company's intranet site with information regarding how merger transaction and transition costs are to be handled.

Recommendation 27 - PPL Electric, LG&E and KU should calculate the rate impact of recovering transaction-related costs in their respective formula rates, and provide these calculations to the Division of Audits and Accounting.

Corrective Action 1: In September 2014, LG&E and KU provided estimated rate impact calculations (interest through June 2014) regarding the consolidated anticipated audit findings, including transaction-related costs, and certain rate under-billings to DAA. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations regarding transaction-related costs (through a then-current date) within 60 days following issuance of a final audit report.

Corrective Action 2: In September 2014, PPL Electric provided DAA with Attachment 1 that identifies the rate impact of recovering transaction-related costs through PPL Electric's transmission formula rate.

Recommendation 28 - PPL Electric, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to the incorrect allocation of transaction-related costs, calculated with interest in accordance to the Commission-approved formula rate protocols for PPL Electric and under § 35.19a of the Commission's regulations for LG&E and KU.

Corrective Action 1: LG&E and KU will refund or credit to ratepayers amounts recovered through the transmission formula rate due to such transaction-related costs, with interest, and anticipate that they will do so within 30 days of each applicable final Commission order accepting the respective refund report filed in response to Recommendation 27.

Corrective Action 2: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the transaction-related costs improperly included in and recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

8. ***Allowance for Funds Used During Construction***

Recommendation 29 - KU should revise and implement procedures going forward to ensure its AFUDC base and rate calculation is consistent with Electric Plant Instruction 3(17) and other applicable Commission requirements.

Corrective Action 1: Beginning with the February 2012 accounting close, KU modified its PowerPlant fixed asset accounting system to properly account for AFUDC. The PowerPlant automated AFUDC calculation was updated to compound interest semiannually rather than monthly.

Corrective Action 2:
During August 2012, KU finalized modifications to its AFUDC accounting policy and procedures to record AFUDC in accordance with Electric Plant Instruction 3(17) and Federal Power Commission Order 561.

9. ***Formula Rate Line References***

Recommendation 30 - LG&E and KU should develop and implement controls to ensure accurate and complete line references.

Corrective Action: During 2012 and 2013, LG&E and KU developed and implemented, enhanced controls and procedures for the transmission formula rate template to ensure appropriate references going forward, similar to Sarbanes-Oxley–level controls. LG&E and KU strengthened spreadsheet controls on the formula rate template, such as password protection, increased automation and protection for calculations, clearly labeled input data entry, and increased internal cross-check features. LG&E and KU implemented written process documentation and a narrative for the controls describing the specific procedures and responsibilities for calculating and reviewing the transmission formula rate relating to calculation performed by its Rates Department, reviews performed by its Rates, Accounting, and Transmission Departments and sign-off at the senior management level prior to posting.

Recommendation 31 - LG&E and KU should submit a filing with the Commission under FPA section 205 to address the incorrect formula rate line references.

Corrective Action: LG&E and KU anticipate that they will submit the recommended FPA Section 205 filing(s) relating to incorrect formula rate line references within 90 days of the issuance of a final audit report.

10. FERC Form No. 60 Reporting

Recommendation 32 - LKS and PPL Services should develop and implement procedures to ensure proper account classification, consistent reporting, and completion of all supporting schedules of the FERC Form No. 60. As part of these procedures, incorporate an annual review to ensure the FERC Form No. 60 filed with the Commission is complete and accurate.

Corrective Action 1: In March 2012, during preparation for the 2012 Form 60 filing, LG&E and KU developed a query within its Oracle financial system to better identify and capture LKS intercompany transactions that should be distinguished as convenience payments. Further enhancements were made to this query throughout 2013 to improve the efficiency of the query and to reduce manual adjustments to identify the convenience payments. In January and February 2013 LG&E and KU set up additional expenditure types within Oracle to also aid in identifying convenience payments.

Corrective Action 2: In November 2012, LG&E and KU developed a document to further educate employees on the identification of convenience payments. This document, along with a decision tree, has been shared with all employees via their intranet site.

Corrective Action 3: PPL Services implemented an automated process in 2012, using delivered allocation functionality in its general ledger software. The automated process performs the reclassification among Accounts 920, 921 and 923 based on cost type. The automated process mirrors the manual reclassification journal entries reflected in the 2011 FERC Form 60. As an additional control for PPL Services, beginning in 2012, the cost types in accounts 920, 921, and 923 are reviewed on a monthly basis to ensure that amounts are appropriately classified in these accounts.

Corrective Action 4: PPL Services developed written procedures for the preparation of Form 60. Prior to the filing of the 2013 Form 60 which occurred on April 30, 2014, Corporate Audit Services reviewed the process for preparing PPL Services' Form 60, the procedures used to allocate cost in the 2013 Form 60, and the completeness and accuracy of the 2013 Form 60. Management has requested Corporate Audit Services to include a review of the Form 60 in its audit plan.

Recommendation 33 - LKS and PPL Services should refile 2010 FERC Form No. 60, correcting all reporting errors within 90 days after this report is issued.

Corrective Action 1: LKS will refile the 2010 FERC Form No. 60 within 90 days of the date the final audit report is issued.

Corrective Action 2: PPL Services will refile the 2010 FERC Form No. 60 within 90 days of the date the final audit report is issued.

II. **Draft Audit Report Section V. Other Matters**

Formula Rate Recovery of Intangible Plant

Recommendation - LG&E and KU submit a filing with the Commission under FPA section 205 to adopt the revisions for intangible plant MISO proposed in Docket No. ER12-297-000 and incorporate them into KU and LG&E's formula rate template under their joint OATT.

Corrective Action: LG&E and KU anticipate that they will submit the recommended FPA Section 205 filing(s) adopting revisions for intangible plant as proposed by MISO and incorporating those changes into the formula rate template under their joint OATT within 90 days of the issuance of a final audit report.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(j)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

The prospectuses of the most recent stock or bond offerings.

Response:

See attached.

NEW ISSUE

Subject to the conditions and exceptions set forth under the heading "Tax Treatment," Bond Counsel is of the opinion that, under current law, interest on the Bonds offered hereby will be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel is further of the opinion that interest on the Bonds will be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under current law, the principal of the Bonds will be exempt from ad valorem taxes in Kentucky. Issuance of the Bonds is subject to receipt of a favorable tax opinion of Bond Counsel as of the date of delivery of the Bonds. See "Tax Treatment" herein.

$125,000,000
County of Trimble, Kentucky
Pollution Control Revenue Refunding Bonds, 2016 Series A, Due September 1, 2044 (Louisville Gas and Electric Company Project)

Dated: Date of Original Issuance

The County of Trimble, Kentucky, Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project) (the "Bonds") will be special and limited obligations of the County of Trimble, Kentucky (the "Issuer"), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to a Loan Agreement with Louisville Gas and Electric Company (the "Company"), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds will not constitute general obligations of the Issuer or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky.

Principal of, and interest on, the Bonds are further secured by the delivery to U.S. Bank National Association, as Trustee, of First Mortgage Bonds of

LOUISVILLE GAS AND ELECTRIC COMPANY

From and after the date of the issuance and delivery of the Bonds, the Bonds will bear interest at a Weekly Rate, determined by the Remarketing Agent, J.P. Morgan Securities LLC, in accordance with the Indenture, payable on the first Business Day of each calendar month. The interest rate period, interest rate and interest rate mode will be subject to change under certain conditions, as described in this Official Statement. The Bonds will be subject to optional redemption, extraordinary optional redemption and mandatory redemption following a determination of taxability prior to maturity, as described in this Official Statement. The Bonds are subject to optional purchase on the demand of the owner and to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode, in each case as described in this Official Statement.

PRICE: 100%

The Bonds, when issued, will be registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company ("DTC"), New York, New York. DTC will act as securities depository. Purchases of beneficial ownership interests in the Bonds will be made in book-entry only form in denominations of $100,000 and multiples thereof. Purchasers will not receive certificates representing their beneficial interests in the Bonds. See the information contained under the heading "Summary of the Bonds — Book-Entry-Only System" in this Official Statement. The principal or redemption price of and interest on the Bonds will be paid by U.S. Bank National Association, as Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC's Direct and Indirect Participants, as more fully described herein.

Liquidity to pay the purchase price of the Bonds that are tendered and not remarketed will be provided by the Company. It is not anticipated that a liquidity or credit facility will be provided by any other party. Prospective purchasers of the Bonds should rely solely on the ability of the Company to provide for the purchase of the Bonds that are tendered and not remarketed. The failure of the Company to pay the purchase price of any Bond tendered by the holder thereof and not remarketed is an Event of Default under the Indenture.

The Bonds are offered when, as and if issued and received by the Underwriter, subject to prior sale, withdrawal or modification of the offer without notice, and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois and Gerald A. Reynolds, General Counsel, Chief Compliance Officer and Corporate Secretary of the Company, for the Issuer by its County Attorney, and for the Underwriter by its counsel, McGuireWoods LLP, Chicago, Illinois. It is expected that the Bonds will be available for delivery to DTC in New York, New York on or about September 15, 2016.

J.P. Morgan

September 7, 2016

The Bonds are exempt from registration under the Securities Act of 1933, as amended.

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Underwriter to give any information or to make any representation with respect to the Bonds, other than those contained in this Official Statement, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Underwriter has provided the following sentence for inclusion in this Official Statement. The Underwriter has reviewed the information in this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the completeness of such information. The information and expressions of opinion in this Official Statement are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof.

In connection with the offering of the Bonds, the Underwriter may over-allot or effect transactions which stabilize or maintain the market prices of such Bonds at levels above those which might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE OFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

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OFFICIAL STATEMENT

$125,000,000
County of Trimble, Kentucky
Pollution Control Revenue Refunding Bonds,
2016 Series A, Due September 1, 2044
(Louisville Gas and Electric
Company Project)

Introductory Statement

This Official Statement, including the cover page and Appendices, is provided to furnish information in connection with the offer and sale by the County of Trimble, Kentucky (the "Issuer") of its Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project), in the aggregate principal amount of $125,000,000 (the "Bonds") to be issued pursuant to an Indenture of Trust dated as of September 1, 2016 (the "Indenture") between the Issuer and U.S. Bank National Association (the "Trustee"), as Trustee, Paying Agent and Bond Registrar.

Pursuant to a Loan Agreement by and between Louisville Gas and Electric Company (the "Company") and the Issuer, dated as of September 1, 2016, (the "Loan Agreement"), proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, will be loaned by the Issuer to the Company.

The proceeds of the Bonds (other than any accrued interest) will be applied in full, together with other moneys made available by the Company, to pay and discharge (i) $83,335,000 in outstanding principal amount of "County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2000 Series A (Louisville Gas and Electric Company Project)," dated August 9, 2000 (the "2000 Bonds") and (ii) $41,665,000 in outstanding principal amount of "County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2002 Series A (Louisville Gas and Electric Company Project)," dated October 23, 2002 (the "2002 Bonds" and, collectively with the 2000 Bonds, the "Prior Bonds"), previously issued by the Issuer to refinance certain pollution control facilities (the "Project") owned by the Company. For information regarding the pollution control facilities, see "The Project."

It is a condition to the Underwriter's obligation to purchase the Bonds that the Company irrevocably instruct the trustees in respect of the Prior Bonds, on or prior to the date of issuance of the Bonds, to call the Prior Bonds for redemption.

The Company will repay the loan under the Loan Agreement by making payments to the Trustee in sufficient amounts to pay the principal or redemption price of and interest on the Bonds and will further agree under the Loan Agreement to make payments of the purchase price of the Bonds tendered for purchase to the extent funds are not otherwise available under the Indenture. See "Summary of the Loan Agreement — General." Pursuant to the Indenture, the Issuer's rights under the Loan Agreement (other than with respect to certain rights to indemnification, reimbursement, notice and payment of expenses) will be assigned to the Trustee as security for the Bonds.

For the purpose of further securing the Bonds, the Company will issue and deliver to the Trustee a series of the Company's First Mortgage Bonds, Collateral Series 2016TCA (the "First Mortgage Bonds"). The principal amount, maturity date and interest rate (or method of determining interest rates) of such First Mortgage Bonds will correspond to the principal amount, maturity date and interest rate (or method of determining interest rates) of the Bonds. The First Mortgage Bonds will only be payable, and interest thereon will only accrue, as described herein. See "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of the First Mortgage Bonds and the First Mortgage Indenture." The First Mortgage Bonds will not provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture.

The First Mortgage Bonds will be issued under, and will be secured by, the Company's Indenture, dated as of October 1, 2010, as previously supplemented and as to be supplemented by a supplemental indenture to be dated as of September 1, 2016 relating to the Bonds (the "First Mortgage Supplemental Indenture" and the Indenture, as so supplemented, the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee").

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of PPL Corporation or the Company's other affiliates will be obligated to make any payments due under the Loan Agreement or First Mortgage Bonds or any other payments of principal, interest, redemption price or purchase price of the Bonds.

The Bonds will be special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal or redemption price of and interest on, and purchase price of, the Bonds will be limited solely to the revenues and other amounts received by the Trustee under the Indenture pursuant to the Loan Agreement, including amounts payable on the First Mortgage Bonds. The Bonds will not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof.

J.P. Morgan Securities LLC will be appointed in accordance with the Indenture to serve as Remarketing Agent for the Bonds. The Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreement, the Indenture, the First Mortgage Bonds and the First Mortgage Indenture are included in this Official Statement. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of completeness. All references in this Official Statement to the documents are qualified in their entirety by reference to such documents, and references in this Official Statement to the Bonds are qualified in their entirety by reference to the definitive form of the Bonds included in the Indenture. Copies of the Loan Agreement and the Indenture will be available for inspection at the principal corporate trust office of the Trustee and, until the issuance of the Bonds, may be obtained from the Underwriter. The First Mortgage Indenture (including the form of the First Mortgage Bonds) is available for inspection at the office of the Company in Louisville, Kentucky, and at the corporate trust office of the First Mortgage Trustee, in Pittsburgh, Pennsylvania. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. Appendix A to this Official Statement and all information contained under the headings "The Project" and "Use of Proceeds" has been furnished by the Company. The Issuer, Bond Counsel and the Remarketing Agent assume no responsibility for the accuracy or completeness of such Appendix A or such information. The Underwriter has reviewed the information in Appendix A to this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the completeness of such Appendix A or such information. Appendix B to this Official Statement contains the proposed form of opinion of Bond Counsel to be delivered in connection with the issuance and delivery of the Bonds.

This Official Statement only describes the terms and provisions applicable to the Bonds while accruing interest at the Weekly Rate. In the event of a remarketing of the Bonds on or after a Conversion, a supplement to this Official Statement or a new reoffering circular will be prepared describing the new terms and provisions then applicable to such Bonds.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) issue the Bonds to pay and discharge the Prior Bonds, (b) lend the proceeds from the sale of the Bonds to the Company for such purpose and (c) enter into and perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS WILL BE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY OR ON BEHALF OF THE ISSUER UNDER THE LOAN AGREEMENT, INCLUDING AMOUNTS PAYABLE ON THE FIRST MORTGAGE BONDS. THE BONDS WILL NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND WILL NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

The Project

The Project being refinanced with the Bonds has been completed and is the property of the Company, subject to the lien of the First Mortgage Indenture. The Project consists of certain air and water pollution control facilities of the Company at the Company's Trimble County Generating Station located in Trimble County, Kentucky (the "Generating Station"), which facilities are an integral component of the comprehensive system of air and water pollution control and solid waste disposal facilities at the Generating Station (the "Project").

The Department for Natural Resources and Environmental Protection of the Commonwealth of Kentucky (now the Energy and Environment Cabinet), the agency exercising jurisdiction with respect to the Project, has certified that the Project, as designed (which includes the facilities constituting the Project), is in furtherance of the purposes of abating and controlling atmospheric and water pollutants or contaminants, as applicable.

Use of Proceeds

The proceeds from the sale of the Bonds (other than any accrued interest) will be used, together with funds to be provided by the Company, to pay and discharge at a redemption price of 100% of the principal amount thereof, plus accrued interest, all of the outstanding Prior Bonds, on the date of the issuance of the Bonds. The Prior Bonds currently bear interest at an auction rate and mature on August 1, 2030 and October 1, 2032. For the twelve months ended June 30, 2016, the weighted average interest rate on the Prior Bonds was 0.486%.

Summary of the Bonds

General

The Bonds will be issued in the aggregate principal amount set forth on the cover page of this Official Statement. The Bonds will mature as to principal on September 1, 2044. The Bonds are also subject to redemption prior to maturity as described in this Official Statement.

The Bonds will bear interest at a Weekly Rate, and interest will be payable on the first Business Day of each calendar month, until a Conversion to another Interest Rate Mode is specified by the Company or until the redemption or maturity of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the Flexible Rate, (ii) the Daily Rate, (iii) the Weekly Rate, (iv) the Semi-Annual Rate, (v) the Annual Rate, (vi) the Long Term Rate, (vii) the LIBOR Index Rate and (viii) the SIFMA-Based Term Rate.

This Official Statement only describes the terms and provisions applicable to the Bonds while accruing interest at the Weekly Rate. In the event of a remarketing of the Bonds on or after a Conversion to another Interest Rate Mode, a supplement to this Official Statement or a new reoffering circular will be prepared describing the new terms and provisions then applicable to such Bonds.

During each Weekly Rate Period, the interest rate for the Bonds will be the rate established by the Remarketing Agent no later than 4:00 p.m. (New York City time) on the day preceding such Weekly Rate Period or, if such day is not a Business Day, on the next preceding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions (as defined below), and assuming that all Bonds are then available for sale, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 12% per annum. If for any reason the interest rate for the Bonds is not determined by the Remarketing Agent, except as described below under "Conversion of Interest Rate Modes — Cancellation of Conversion of Interest Rate Mode," the interest rate for the next succeeding interest rate period will be the interest rate in effect for the Bonds for the preceding interest rate period.

Interest on the Bonds will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment. The Record Date will be the close of business on the Business Day immediately preceding each Interest Payment Date.

The Bonds initially will be issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Official Statement. See "Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in denominations of $100,000 and multiples thereof.

So long as the Bonds are held in book-entry-only form, the principal or redemption price of and interest on, and purchase price of, the Bonds will be payable by the Trustee, as paying agent (the "Paying Agent"), through the facilities of DTC (or a successor depository).

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the designated office of the Trustee, as bond registrar (the "Bond Registrar"), accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "Purchases of Bonds — Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "Purchases of Bonds — Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated:

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such by the respective systems of DTC and each Participant (as defined herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than (i) a Saturday or Sunday or legal holiday or a day on which banking institutions in the city in which the designated office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Company or the Remarketing Agent is located are authorized by law or executive order to close or (ii) a day on which the New York Stock Exchange is closed.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means initially the date of original issuance of the Bonds, and thereafter means the date on which any Conversion becomes effective.

"*Interest Payment Date*" means the first Business Day of each calendar month and any Conversion Date (including the date of a failed Conversion). In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate, the Long Term Rate, the LIBOR Index Rate and the SIFMA-Based Term Rate.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Weekly Rate Period*" means the period beginning on, and including, the date of issuance of the Bonds, and ending on, and including, the next Wednesday, and thereafter the period beginning on, and including, each Thursday and ending on, and including, the earliest of the next Wednesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Conversion of Interest Rate Modes

The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, other than a Conversion from the Weekly Rate Period to the Daily Rate Period.

Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "Redemptions — Optional Redemption" below); provided that any Conversion from the Weekly Rate Period to the Daily Rate Period must be on a Thursday; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; and (iii) after a determination is made requiring mandatory redemption of all Bonds pursuant to the Indenture (see "Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

The Bond Registrar will notify each registered owner of the Conversion by first class mail at least 15 days before each Conversion Date. The notice will state those matters required to be set forth therein under the Indenture.

Notwithstanding the foregoing, no Conversion will occur if (A) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (B) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent, or (C) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, the Bonds will remain in the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Wednesday) at the rate determined by the Remarketing Agent on the failed Conversion Date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds

Purchases of Bonds on Demand of Owner. Any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its designated office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing.

Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 12:00 noon (New York City time) on such Purchase Date.

If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant (as defined under the heading "Book-Entry-Only System"). If the Bonds are in certificated form, demands for purchase may be made only by registered owners.

Mandatory Purchase of Bonds. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof on each Conversion Date. Such tender and purchase will be required even if the Conversion is canceled pursuant to the Indenture.

Notice to owners of a mandatory purchase of Bonds on a Conversion Date will be given by the Bond Registrar, together with the notice of such Conversion, by first class mail at least 15 days before each Conversion Date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture.

Remarketing and Purchase of Bonds. The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its commercially reasonable best efforts to remarket Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

The purchase price of Bonds tendered for purchase will be paid by the Tender Agent from moneys derived from the remarketing of such Bonds by the Remarketing Agent and, if such remarketing proceeds are insufficient, from moneys made available by the Company.

The Company is obligated to purchase any Bonds tendered for purchase to the extent such Bonds have not been remarketed. Any such purchases by the Company will not result in the extinguishment of the purchased Bonds. The Company currently maintains lines of credit or other liquidity facilities in amounts determined by it to be sufficient to meet its current needs and expects to continue to maintain such lines of credit or other liquidity facilities from time to time to the extent determined by it to be necessary to meet its then-current needs. The Trustee, any Paying Agent, the Tender Agent and the owners of the Bonds have no right to draw under any line of credit or other liquidity facility maintained by the Company. There is no provision in the Indenture or the Loan Agreement requiring the Company to maintain such financing arrangements which may be discontinued at any time without notice. The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase pursuant to the Indenture.

Any deficiency in purchase price payments resulting from the Remarketing Agent's failure to deliver remarketing proceeds of all Bonds with respect to which the Remarketing Agent notified the Tender Agent were remarketed will not result in an Event of Default under the Indenture until the opening of business on the next succeeding Business Day unless the Company fails to provide sufficient funds to pay such purchase price by the opening of business on such next succeeding Business Day. If sufficient funds are not available for the purchase of all tendered Bonds, no purchase of Bonds will be consummated, but failure to consummate such purchase will not be deemed to be an Event of Default under the Indenture if sufficient funds have been provided in a timely manner by the Company to the Tender Agent for such purpose.

Payment of Purchase Price. Payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent at or prior to 12:00 noon (New York City time). If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day. When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

Special Considerations Relating to the Purchase and Remarketing of the Bonds

The Remarketing Agent is Paid by the Company. The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described in this Official Statement. The Remarketing Agent has been appointed by the Company and is paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent Routinely Purchases Bonds for its Own Account. The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds May be Offered at Different Prices on Any Date Including an Interest Rate Determination Date. Pursuant to the Indenture, the Remarketing Agent is required to determine the applicable rate of interest that, in its judgment, is the minimum rate necessary, based on Prevailing Market Conditions, and assuming that all Bonds are then available for sale, for the Remarketing Agent to sell the Bonds on the day the rate is set at their principal amount (without regard to accrued interest). The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). The Indenture requires that the Remarketing Agent use its commercially reasonable best efforts to sell tendered Bonds at par, plus accrued interest, if any. There may or may not be Bonds tendered and remarketed on a day that the interest rate on the Bonds is set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third-party buyers for all of the Bonds at the remarketing price.

Secondary Market Transactions. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the interest rate on the Bonds is set, at a discount to par to some investors.

The Ability to Sell the Bonds other than through the Tender Process May Be Limited. The Remarketing Agent may buy and sell Bonds other than in connection with the tender and remarketing process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process set forth in the Indenture.

Under Certain Circumstances, the Remarketing Agent May Be Removed, Resign or Cease Remarketing the Bonds, Without a Successor Being Named. Under certain circumstances, the Remarketing Agent may be removed or have the ability to resign or cease its remarketing efforts, without a successor having been named, subject to the terms of the Remarketing Agreement and the Indenture.

Redemptions

Optional Redemption. The Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events occur within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date of the Loan Agreement, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project;

(ii) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(iii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iv) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the Generating Station have occurred, which, in the judgment of the Company, render the continued operation of such Generating Station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in clean air or other air and water pollution control requirements or solid waste disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable;

(v) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(vi) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the Generating Station to such extent that the Company will be prevented from carrying on its normal operations at such Generating Station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer, the Company or the First Mortgage Trustee in the event of damage, destruction or condemnation of all or a portion of the Project, subject to compliance with the terms of the First Mortgage Indenture and receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user of the Project within the meaning of Section 147 of the Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability will be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (i) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (A) gives the Company and the Trustee prompt notice of the commencement thereof, and (B) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (ii) either (A) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (B) the Company will exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. Notice of redemption will be given by mailing a redemption notice conforming to the provisions and requirements of the Indenture by first class mail to the registered owners of the Bonds to be redeemed not less than 15 days prior to the redemption date. Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. If the provisions for discharging the Indenture set forth below under the heading "Summary of the Indenture — Discharge of Indenture" have not been complied with, any redemption notice may state that it is conditional on there being sufficient moneys to pay the full redemption price for the Bonds to be redeemed and that if sufficient funds have not been received by the Trustee by the opening of business on the redemption date, such notice shall be of no effect. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Security

Payment of the principal or redemption price of and interest on the Bonds will be secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount or redemption price of the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The payment of the principal or redemption price of and interest on the Bonds will be further secured by the First Mortgage Bonds. The principal amount of the First Mortgage Bonds will equal the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds ("Redemption Demand"), or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have become immediately due and payable, such First Mortgage Bonds will begin to bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date or dates to which interest on the Bonds has been paid in full, will be payable in accordance with the Supplemental Indenture. See "Summary of the First Mortgage Bonds and the First Mortgage Indenture."

The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture. The Company is not required under the Loan Agreement or Indenture to provide any letter of credit or liquidity support for the Bonds. The First Mortgage Bonds are secured by a lien on certain property owned by the Company. In certain circumstances, the Company is permitted to reduce the aggregate principal amount of its First Mortgage Bonds held by the Trustee, but in no event to an amount lower than the aggregate outstanding principal amount of the Bonds.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book-entry-only system have been obtained from DTC. The Issuer, the Company and the Underwriter make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners, however, are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry only system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial

Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If fewer than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner may give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and will effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds on DTC's records to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee, or the Issuer, at the request of the Company, may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository for the Bonds). Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be delivered as described in the Indenture (see "— Revision of Book-Entry-Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture and the Company's obligations under the Loan Agreement and the First Mortgage Bonds, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book-entry-only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Underwriter cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Official Statement.

THE ISSUER, THE COMPANY, THE UNDERWRITER, THE REMARKETING AGENT AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds

In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $100,000 and multiples thereof. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the designated office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Bond Registrar may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Summary of the Loan Agreement

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the Loan Agreement. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Loan Agreement , for the detailed provisions thereof.

General

The term of the Loan Agreement will commence as of its date and end on the earliest to occur of September 1, 2044, or the date on which all of the Bonds have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company will agree to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal or redemption price of and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company will also agree to pay (a) the agreed upon fees and expenses of the Trustee, the Bond Registrar, the Tender Agent and the Paying Agent and all other amounts which may be payable to the Trustee, the Bond Registrar, the Paying Agent and the Tender Agent, as may be applicable, under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company will covenant and agree with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company will cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture (see "Summary of the Bonds — Purchases of Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the fees and reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar and the Tender Agent, and amounts related to indemnification) will be assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer will agree not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company will execute and deliver to the Trustee the First Mortgage Bonds on the date of issuance of the Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee will equal the aggregate principal amount of the

Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a Redemption Demand, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have become immediately due and payable, such First Mortgage Bonds will then bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will then be payable. See, however, "Summary of the Indenture — Waiver of Events of Default."

Upon payment of the principal or redemption price of and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds will be registered in the name of the Trustee and will be non transferable, except to effect transfers to any successor trustee under the Indenture.

Payment of Taxes

The Company will agree to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under the heading "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole"). The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain, preserve and keep the Project or cause the Project to be maintained, preserved and kept in good repair, working order and condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as air and water pollution control and abatement facilities under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended. However, the Company will have no obligation to maintain, preserve, keep, repair, replace or renew any portion of the Project, the maintenance, preservation, keeping, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements are deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer, the Company or the First Mortgage Trustee receives net proceeds from insurance or a condemnation award in connection therewith, the Company must, subject to the requirements of the First Mortgage Indenture, (i) cause such net proceeds to be used to repair or restore the Project or (ii) take any other action, including the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part."

Project Insurance

The Company will insure the Project in accordance with the provisions of the First Mortgage Indenture.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, will not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another entity, provided the acquirer of the Company's assets or the entity with which it will consolidate with or merge into is a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America or the District of Columbia, is qualified and admitted to do business in the Commonwealth of Kentucky, and assumes in writing all of the obligations and covenants of the Company under the Loan Agreement and delivers a copy of such assumption to the Issuer and the Trustee.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys' fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an "Event of Default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies"), and such failure shall cause an event of default under the Indenture;

(2) failure by the Company to observe and perform any covenant, condition or agreement on its part to be observed or performed, other than as referred to in paragraph (1) above, for a period of 30 days after written notice by the Issuer or Trustee, subject to extension by the Issuer and the Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, the Issuer and the Trustee will not unreasonably withhold their

consent to an extension of such time if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(4) the occurrence of an Event of Default under the Indenture; or

(5) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee;

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes, (ii) to execute and deliver the First Mortgage Bonds to the Trustee on or before the date of issuance of the Bonds in an amount equal to the principal amount of the Bonds; (iii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another entity unless certain provisions of the Loan Agreement are satisfied; and (iv) to make loan payments and certain other payments under the provisions of the Loan Agreement) may he suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening and continuance of an Event of Default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

In the event of a default in payment of the principal or redemption price of or interest on the Bonds and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such Event of Default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds and the First Mortgage Indenture" and "Summary of the Indenture — Defaults and Remedies." Any amounts collected upon the happening of any such Event of Default must be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof bas been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

Options to Prepay; Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the headings "Summary of the Bonds — Redemptions — Optional Redemption," "Extraordinary Optional Redemption in Whole" and "Extraordinary Optional Redemption in Whole or in Part." Upon the occurrence of the event described under the beading "Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability," the Company will be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price must be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to 100% of the principal amount plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent, the Bond Registrar and the Tender Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No alteration, amendment, change, supplement or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any alteration, amendment, change, supplement or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such alterations, amendments, changes, supplements or modifications, the Loan Agreement may be altered, amended, changed, supplemented or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see "Summary of the Indenture — Supplemental Indentures" for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an alteration, amendment, change, supplement or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the third paragraph of "Summary of the Indenture — Supplemental Indentures."

Summary of the First Mortgage Bonds and the First Mortgage Indenture

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the First Mortgage Bonds and the First Mortgage Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

In connection with the issuance of the Bonds, the First Mortgage Bonds will be issued in a principal amount equal to the principal amount of the Bonds and will constitute a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an event of default under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non negotiable, and will be non transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the First Mortgage Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to *permitted liens* and exclusions as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage, transportation and distribution of natural gas (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than *excepted property*, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to below as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business or its natural gas storage, transportation and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture or required so to be; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities or natural gas storage, transportation and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such permitted liens include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a permitted lien under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. As of June 30, 2016, first mortgage bonds in an aggregate principal amount of $1,659,304,000 were outstanding under the First Mortgage Indenture, of which $574,304,000 were issued to secure the Company's payment obligations with respect to its outstanding pollution control and environmental facilities revenue bonds, including the Bonds.

First mortgage bonds of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of *property additions* (as described below) which do not constitute *funded property* (generally, *property additions* which have been made the basis of the authentication and delivery of first mortgage bonds, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired *funded property* or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of *retired securities* (as described below); or

- an amount of cash deposited with the First Mortgage Trustee.

Property additions generally include any property which is owned by the Company and is subject to the lien of the First Mortgage Indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of the Company's operating expense accounts in accordance with U.S. generally accepted accounting principles.

Retired securities means, generally, first mortgage bonds which are no longer outstanding under the First Mortgage Indenture, which have not been retired by the application of *funded cash* and which have not been used as the basis for the authentication and delivery of first mortgage bonds, the release of property or the withdrawal of cash.

At June 30, 2016, approximately $1.3 billion of *property additions* and $250 million of *retired securities* were available to be used as the basis for the authentication and delivery of first mortgage bonds. The Company intends to issue the First Mortgage Bonds on the basis of *retired securities*.

Release of Property

Unless an *event of default* has occurred and is continuing, the Company may obtain the release from the lien of the First Mortgage Indenture of any Mortgaged Property, except for cash held by the First Mortgage Trustee, upon delivery to the First Mortgage Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66-2/3%) of the cost of the property to be released (or, if less, the *fair value* to the Company of such property at the time it became *funded property*) exceeds the aggregate of:

- an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property to be released and delivered to the First Mortgage Trustee;

- an amount equal to 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of certified *property additions* not constituting *funded property* after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the release);

- the aggregate principal amount of first mortgage bonds the Company would be entitled to issue on the basis of *retired securities* (with such entitlement being waived by operation of such release);

- the aggregate principal amount of first mortgage bonds delivered to the First Mortgage Trustee (with such first mortgage bonds to be canceled by the First Mortgage Trustee);

- any amount of cash and/or an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property released that is delivered to the trustee or other holder of a lien prior to the lien of the First Mortgage Indenture, subject to certain limitations described in the First Mortgage Indenture; and

- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

As used in the First Mortgage Indenture, the term *purchase money lien* means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property.

Unless an *event of default* has occurred and is continuing, property which is not *funded property* may generally be released from the lien of the First Mortgage Indenture without depositing any cash or property with the First Mortgage Trustee as long as (a) the aggregate amount of *cost* or *fair value* to the Company (whichever is less) of all *property additions* which do not constitute *funded property* (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the *cost* or *fair value* (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value to the Company (whichever is less) of *property additions* acquired or made within the 90-day period preceding the release.

The First Mortgage Indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the First Mortgage Trustee.

If the Company retains any interest in any property released from the lien of the First Mortgage Indenture, the First Mortgage Indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof.

Withdrawal of Cash

Unless an *event of default* has occurred and is continuing, and subject to certain limitations, cash held by the First Mortgage Trustee may, generally, (1) be withdrawn by the Company (a) to the extent of sixty-six and two-thirds percent (66-2/3%) of the *cost* or *fair value* to the Company (whichever is less) of *property additions* not constituting *funded property*, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of first mortgage bonds that the Company would be entitled to issue on the basis of *retired securities* (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding first mortgage bonds delivered to the First Mortgage Trustee; or (2) upon the Company's request, be applied to (a) the purchase of first mortgage bonds in a manner and at a price approved by the Company or (b) the payment (or provision for payment) at stated maturity of any first mortgage bonds or the redemption (or provision for payment) of any first mortgage bonds which are redeemable; provided, however, that cash deposited with the First Mortgage Trustee as the basis for the authentication and delivery of first mortgage bonds may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the First Mortgage Trustee for such purpose.

Events of Default

An "event of default" occurs under the First Mortgage Indenture if

- the Company does not pay any interest on any first mortgage bonds within 30 days of the due date;
- the Company does not pay principal or premium, if any, on any first mortgage bonds on the due date;
- the Company remains in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any first mortgage bonds for 90 days after the Company receives a written notice of default stating the Company is in breach and requiring remedy of the breach; the notice must be sent by either the First Mortgage Trustee or holders of 25% of the principal amount of outstanding first mortgage bonds; the First Mortgage Trustee or such holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if the Company initiates corrective action within such 90 day period and the Company is diligently pursuing such action to correct the default; or
- the Company files for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then either the First Mortgage Trustee or the holders of not less than 25% in principal amount of the outstanding first mortgage bonds may declare the principal amount of all of the first mortgage bonds to be due and payable immediately.

Rescission of Acceleration. After the declaration of acceleration has been made and before the First Mortgage Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

- the Company pays or deposits with the First Mortgage Trustee a sum sufficient to pay:
    - all overdue interest;
    - the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;
    - interest on overdue interest to the extent lawful; and
    - all amounts due to the First Mortgage Trustee under the First Mortgage Indenture; and

- all *events of default*, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the First Mortgage Indenture.

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies. Subject to the First Mortgage Indenture, under certain circumstances and to the extent permitted by law, if an *event of default* occurs and is continuing, the First Mortgage Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law.

Control by Holders; Limitations. Subject to the First Mortgage Indenture, if an *event of default* occurs and is continuing, the holders of a majority in principal amount of the outstanding first mortgage bonds will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the First Mortgage Trustee, or

- exercise any trust or power conferred on the First Mortgage Trustee.

The rights of holders to make direction are subject to the following limitations:

- the holders' directions may not conflict with any law or the First Mortgage Indenture; and

- the holders' directions may not involve the First Mortgage Trustee in personal liability where the First Mortgage Trustee believes indemnity is not adequate.

The First Mortgage Trustee may also take any other action it deems proper which is not inconsistent with the holders' direction.

In addition, the First Mortgage Indenture provides that no holder of any first mortgage bond will have any right to institute any proceeding, judicial or otherwise, with respect to the First Mortgage Indenture for the appointment of a receiver or for any other remedy thereunder unless

- that holder has previously given the First Mortgage Trustee written notice of a continuing *event of default*;

- the holders of 25% in aggregate principal amount of the outstanding first mortgage bonds have made written request to the First Mortgage Trustee to institute proceedings in respect of that *event of default* and have offered the First Mortgage Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and

- for 60 days after receipt of such notice, request and offer of indemnity, the First Mortgage Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the First Mortgage Trustee during such 60-day period by the holders of a majority in aggregate principal amount of outstanding first mortgage bonds.

Furthermore, no holder of first mortgage bonds will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders of first mortgage bonds.

However, each holder of first mortgage bonds has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right.

Notice of Default. The First Mortgage Trustee is required to give the holders of the first mortgage bonds notice of any default under the First Mortgage Indenture to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an *event of default* of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such holders until at least 60 days after the occurrence thereof. The Trust Indenture Act currently permits the First Mortgage Trustee to withhold notices of default (except for certain payment defaults) if the First Mortgage Trustee in good faith determines the withholding of such notice to be in the interests of the holders of the first mortgage bonds.

The Company will furnish the First Mortgage Trustee with an annual statement as to its compliance with the conditions and covenants in the First Mortgage Indenture.

Waiver of Default and of Compliance. The holders of a majority in aggregate principal amount of the outstanding first mortgage bonds may waive, on behalf of the holders of all outstanding first mortgage bonds, any past default under the First Mortgage Indenture, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the First Mortgage Indenture that cannot be amended without the consent of the holder of each outstanding first mortgage bond affected.

Compliance with certain covenants in the First Mortgage Indenture or otherwise provided with respect to first mortgage bonds may be waived by the holders of a majority in aggregate principal amount of the affected first mortgage bonds, considered as one class.

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, the Company has agreed to preserve its corporate existence.

The Company has agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which the Company merges, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia; and
    - expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding first mortgage bonds and the performance of all of the Company's covenants under the First Mortgage Indenture; and
    - such entity confirms the lien of the First Mortgage Indenture on the Mortgaged Property; and

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default*, and no event which after notice or lapse of time or both would become an *event of default*, will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;

- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;

- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;

- to add any additional *events of default*, which may be stated to remain in effect only so long as the first mortgage bonds of any one more particular series remains outstanding;
- to change or eliminate any provision of the First Mortgage Indenture or to add any new provision to the First Mortgage Indenture that does not adversely affect the interests of the holders in any material respect;
- to establish the form or terms of any series or tranche of first mortgage bonds;
- to provide for the issuance of bearer securities;
- to evidence and provide for the acceptance of appointment of a successor First Mortgage Trustee or by a co-trustee or separate trustee;
- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of first mortgage bonds;
- to change any place or places where
    - the Company may pay principal, premium and interest,
    - first mortgage bonds may be surrendered for transfer or exchange, and
    - notices and demands to or upon the Company may be served;
- to amend and restate the First Mortgage Indenture as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the holders in any material respect;
- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the holders in any material respect; or
- to increase or decrease the maximum principal amount of first mortgage bonds that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the First Mortgage Indenture so as to require changes to the First Mortgage Indenture or so as to permit changes to, or the elimination of, provisions which, at the date of the First Mortgage Indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the First Mortgage Indenture, the First Mortgage Indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and the Company and the First Mortgage Trustee may, without the consent of any holders, enter into one or more supplemental indentures to effect or evidence such amendment.

With Holder Consent. Except as provided above, the consent of the holders of at least a majority in aggregate principal amount of the first mortgage bonds of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the First Mortgage Indenture pursuant to a supplemental indenture. However, if less than all of the series of outstanding first mortgage bonds are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected series, considered as one class. Moreover, if the first mortgage bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of first mortgage bonds of one or more, but less than all, of such tranches, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the holder of each outstanding first mortgage bond directly affected thereby:

- change the stated maturity of the principal or interest on any first mortgage bond (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or the method of calculating such rates) or change the currency in which any first mortgage bond is payable, or impair the right to bring suit to enforce any payment;

- create any lien (not otherwise permitted by the First Mortgage Indenture) ranking prior to the lien of the First Mortgage Indenture with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the First Mortgage Indenture on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the First Mortgage Indenture), or deprive any holder of the benefits of the security of the lien of the First Mortgage Indenture;

- reduce the percentages of holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the First Mortgage Indenture or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the First Mortgage Indenture; or

- modify certain of the provisions of the First Mortgage Indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to first mortgage bonds.

A supplemental indenture which changes, modifies or eliminates any provision of the First Mortgage Indenture expressly included solely for the benefit of holders of first mortgage bonds of one or more particular series or tranches will be deemed not to affect the rights under the First Mortgage Indenture of the holders of first mortgage bonds of any other series or tranche.

Satisfaction and Discharge

Any first mortgage bonds or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the First Mortgage Indenture and, at the Company's election, the Company's entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the First Mortgage Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or

- in the case of a deposit made prior to the maturity of such first mortgage bonds, non-redeemable *eligible obligations* (as defined in the First Mortgage Indenture) sufficient, or

- a combination of the items listed in the preceding two bullet points, which in total are sufficient, to pay when due the principal of, and any premium, and interest due and to become due on such first mortgage bonds or portions of such first mortgage bonds on and prior to their maturity.

The Company's right to cause its entire indebtedness in respect of the first mortgage bonds of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The First Mortgage Indenture will be deemed satisfied and discharged when no first mortgage bonds remain outstanding and when the Company has paid all other sums payable by it under the First Mortgage Indenture.

All moneys the Company pays to the First Mortgage Trustee or any Paying Agent on First Mortgage Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon the Company's order. Thereafter, the holder of such First Mortgage Bond may look only to the Company for payment.

Duties of the First Mortgage Trustee; Resignation and Removal of the First Mortgage Trustee; Deemed Resignation

The First Mortgage Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the First Mortgage Trustee will be under no obligation to exercise any of the powers vested in it by the First Mortgage Indenture at the request of any holder of first mortgage bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The First Mortgage Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the First Mortgage Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The First Mortgage Trustee may resign at any time by giving written notice to the Company.

The First Mortgage Trustee may also be removed by act of the holders of a majority in principal amount of the then outstanding first mortgage bonds.

No resignation or removal of the First Mortgage Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the First Mortgage Indenture.

Under certain circumstances, the Company may appoint a successor trustee and if the successor accepts, the First Mortgage Trustee will be deemed to have resigned.

Evidence to be Furnished to the First Mortgage Trustee

Compliance with First Mortgage Indenture provisions is evidenced by written statements of the Company's officers or persons selected or paid by the Company. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the First Mortgage Indenture requires the Company to give to the First Mortgage Trustee, not less than annually, a brief statement as to the Company's compliance with the conditions and covenants under the First Mortgage Indenture.

Miscellaneous Provisions

The First Mortgage Indenture provides that certain first mortgage bonds, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the holders of the requisite principal amount of the outstanding first mortgage bonds have given or taken any demand, direction, consent or other action under the First Mortgage Indenture as of any date, or are present at a meeting of holders for quorum purposes.

The Company will be entitled to set any day as a record date for the purpose of determining the holders of outstanding first mortgage bonds of any series entitled to give or take any demand, direction, consent or other action under the First Mortgage Indenture, in the manner and subject to the limitations provided in the First Mortgage Indenture. In certain circumstances, the First Mortgage Trustee also will be entitled to set a record date for action by holders. If such a record date is set for any action to be taken by holders of particular first mortgage bonds, such action may be taken only by persons who are holders of such first mortgage bonds on the record date.

Governing Law

The First Mortgage Indenture and the first mortgage bonds provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. The effectiveness of the lien of the First Mortgage Indenture, and the perfection and priority thereof, will be governed by Kentucky law.

Summary of the Indenture

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer will assign and pledge to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund).

The Bonds will be further secured by the First Mortgage Bonds to be delivered to the Trustee (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The First Mortgage Bonds will be registered in the name of the Trustee and will be nontransferable, except to effect a transfer to any successor trustee. The Bonds will not be directly secured by the Project (although the Project is subject to the lien of the First Mortgage Indenture).

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, will constitute or give rise to any pecuniary liability of the Issuer or any charge upon any of its assets or its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the application of the amounts assigned to payment of the principal or redemption price of and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used solely and only for the payment of the principal or redemption price of and interest on the Bonds, and for the payment of the reasonable fees and expenses to which the Trustee, Bond Registrar, Tender Agent, Authenticating Agent, any Paying Agent and the Issuer are entitled pursuant to the Indenture or the Loan Agreement. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

The Prior Bond Funds

The proceeds from the issuance of the Bonds will be deposited by the Trustee in (i) the County of Trimble, Kentucky, Pollution Control Revenue Bond Fund, 2000 Series A (Louisville Gas and Electric Company Project) and (ii) the County of Trimble, Kentucky, Pollution Control Revenue Bond Fund, 2002 Series A (Louisville Gas and Electric Company Project), in each case in an amount adequate to pay, together with other moneys to be provided by the Company, all principal of and accrued interest on the respective issue of the Prior Bonds to become due and payable on their scheduled redemption dates.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and will be maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture will become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal or redemption price of and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Tender Agent, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Surrender of First Mortgage Bonds

Upon payment of any principal or redemption price of and interest on any of the Bonds which reduces the principal amount of Bonds outstanding, or upon provision for the payment thereof having been made in accordance with the Indenture (see "Discharge of Indenture" above), First Mortgage Bonds in a principal amount equal to the principal amount of the Bonds so paid, or for the payment of which such provision has been made, shall be surrendered by the Trustee to the First Mortgage Trustee. The First Mortgage Bonds so surrendered shall be deemed fully paid and the obligations of the Company thereunder terminated.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) failure to make due and punctual payment of any installment of interest on any Bond within a period of one Business Day from the due date;

(b) failure to make due and punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable, provided that no Event of Default has occurred in respect of failure to receive such purchase price for any Bond if the Company has made the payment at the opening of business on the next Business Day as described in the last paragraph under "Summary of the Bonds — Purchases of Bonds — Remarketing and Purchase of Bonds" above;

(c) failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee or by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an Event of Default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(d) the occurrence of an "Event of Default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default"); or

(e) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under the Indenture, the Trustee may, and upon the written request of the registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding and upon receipt of indemnity reasonably satisfactory to it, must: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds and the First Mortgage Indenture"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable and (iii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders. Interest on the Bonds will cease to accrue on the date of issuance of a declaration of acceleration of payment of the principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners, taking into account the security and remedies afforded to holders of first mortgage bonds under the First Mortgage Indenture. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal or redemption price of and interest on the Bonds then outstanding.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds and shall also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds has been declared due and payable, all such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the United States pursuant to Section 148(f) of the Code, (ii) to the payment of all interest then due on the Bonds, and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee fails or refuses to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture will be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment will be authorized against the general credit of the Issuer.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and will do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding have been declared to be due and payable as a result of a default under the Indenture and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due has been obtained or entered, (i) the Company causes to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which would become due otherwise than by reason of such declaration (with interest thereon as provided in the Indenture) and the expenses of the Trustee in connection with such default and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) have been remedied, then such Event of Default will be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment will be binding upon all Bondholders. No such waiver, rescission and annulment will extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

Upon any waiver or rescission as described above or any discontinuance or abandonment of proceedings under the Indenture, the Trustee shall immediately rescind in writing any Redemption Demand of First Mortgage Bonds previously given to the First Mortgage Trustee. The rescission under the First Mortgage Indenture of a declaration that all first mortgage bonds outstanding under the First Mortgage Indenture are immediately due and payable shall also constitute a waiver of an Event of Default described in paragraph (e) under the subheading "Defaults and Remedies" above and a waiver and rescission of its consequences, provided that no such waiver or rescission shall extend to or affect any subsequent or other default or impair any right consequent thereon.

Notwithstanding the foregoing, nothing in the Indenture will affect the right of a registered owner to enforce the payment of principal or redemption price of and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Indenture provides that the Trustee, as the holder of the First Mortgage Bonds, will be required to attend such meeting or meetings of bondholders under the First Mortgage Indenture or, at its option, deliver its proxy in connection therewith, as relate to matters with respect to which it, as such holder, is entitled to vote or consent. The Trustee, either at any such meeting or meetings or otherwise when the consent of the holders of the First Mortgage Bonds is sought without a meeting, will be required to vote all First Mortgage Bonds then held by it, or consent with respect thereto, proportionately with the vote or consent of the holders of all other securities of the Company then outstanding under the First Mortgage Indenture eligible to vote or consent, as evidenced by, and as to be delivered to the Trustee, a certificate signed by the temporary chairman, the temporary secretary, the permanent chairman, the permanent secretary, or an inspector of votes at any meeting or meetings of security holders under the First Mortgage Indenture, or by the First Mortgage Trustee in the case of consents of such security holders which are sought without a meeting, which states what the signer thereof reasonably believes are the proportionate votes or consents of the holders of all securities (other than the First Mortgage Bonds) outstanding under the First Mortgage Indenture and counted for the purposes of determining whether such security holders have approved or consented to the matter put before them; provided, however, that the Trustee shall not so vote in favor of, or so consent to, any amendment or modification of the First Mortgage Indenture, which, if it were an amendment or modification of the Indenture, would require the consent of the Bondholders as described in the third paragraph under the heading "Summary of the Indenture – Supplemental Indenture," without the prior consent and approval of Bondholders which would be so required; provided further that as a condition to the Trustee voting or giving such consent, the Trustee shall have received a certificate of a Company representative or an opinion of counsel, at its election, stating that such voting or consent is authorized or permitted by the Indenture.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture as shall not be inconsistent with the terms and provisions of the Indenture, without the consent of or notice to the Bondholders, in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to or confer upon the Trustee, as may lawfully be granted, additional rights, remedies, powers or authorities for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights, powers or authorities reserved to or conferred upon the

Issuer, (vi) to make any other modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make other amendments not otherwise permitted by (i), (ii), (iii), (iv) or (v) of this paragraph to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modification or change to the Indenture necessary to provide liquidity or credit support for the Bonds, including any modifications necessary to upgrade or maintain the then applicable ratings on the Bonds or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Notwithstanding the foregoing, the Company, with the consent of the Trustee, may at any time further secure the Bonds by means of a letter of credit, other credit facility or other guarantee or collateral.

Exclusive of supplemental indentures for the purposes set forth in the preceding two paragraphs, the consent of registered owners holding a majority in aggregate principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture may permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer requests the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice must set forth the nature of the proposed supplemental indenture and must state that copies thereof are on file at the designated office of the Trustee for inspection. If, within sixty days (or such longer period as prescribed by the Issuer or the Company) following the giving of such notice, the registered owners holding the requisite amount of the Bonds outstanding have consented to the execution thereof, no Bondholder will have any right to object or question the execution thereof.

No supplemental indenture will become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company will be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the designated office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an Event of Default under the Loan Agreement, the Indenture or the First Mortgage Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement, the Indenture and the First Mortgage Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

Tax Treatment

In the opinion of Bond Counsel, under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds will be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. It is Bond Counsel's further opinion that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds will be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds will be exempt from all ad valorem taxes in Kentucky.

The opinion of Bond Counsel assumes and is conditioned on the payment and discharge of all of the Prior Bonds on or before the 90th day following the date of issuance of the Bonds. The Company has agreed (i) to apply all of the proceeds of the bonds to the payment and discharge of the Prior Bonds within 90 days following the date of issuance of the Bonds, (ii) to provide additional funds necessary, on or prior to a day within 90 days following the date of issuance of the Bonds, to defease and discharge the Prior Bonds on such day and (iii) to give irrevocable instructions on the date of issuance of the Bonds to the trustee in respect of the Prior Bonds directing the redemption of the Prior Bonds.

The opinion of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes will be based upon and will assume the accuracy of certain representations of facts and circumstances, including with respect to the Project, which are within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond Counsel will not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the opinion and subsequent to the original delivery of the Bonds, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel will express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

The Code prescribes a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuer to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer will each covenant to take all actions required of each to assure that the interest on the Bonds will be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinion of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds will be subject to the following exceptions and qualifications:

(a) The Code also provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel will express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

A draft of the opinion of Bond Counsel relating to the Bonds in substantially the form in which it is expected to be delivered on the date of issuance of the Bonds is attached as Appendix B to this Official Statement.

Legal Matters

Certain legal matters incident to the authorization, issuance and sale by the Issuer of the Bonds are subject to the approving opinion of Bond Counsel. Bond Counsel has in the past, and may in the future, act as counsel to the Company with respect to certain matters. Certain legal matters will be passed upon for the Issuer by its County Attorney. Certain legal matters will be passed upon for the Company by Jones Day, Chicago, Illinois, and Gerald A. Reynolds, General Counsel, Chief Compliance Officer and

Corporate Secretary for the Company. Certain legal matters will be passed upon for the Underwriter by its counsel, McGuireWoods LLP, Chicago, Illinois.

Underwriting

J.P. Morgan Securities LLC (the "Underwriter") has agreed, subject to the terms of the bond purchase agreement between the Issuer and the Underwriter, to purchase the Bonds from the Issuer at the public offering price set forth on the cover page of this Official Statement. The Underwriter is committed to purchase all the Bonds if any Bonds are purchased. In connection with the underwriting of the Bonds, the Underwriter will be paid by the Company a fee in the amount of $312,500, which excludes reimbursement for certain reasonable out-of-pocket expenses.

The Underwriter may offer and sell the Bonds to certain dealers and others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriter.

In connection with the offering of the Bonds, the Underwriter may over-allot or effect transactions that stabilize or maintain the market prices of such Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

Pursuant to an Inducement Letter, the Company has agreed to indemnify the Underwriter and the Issuer against certain civil liabilities, including liabilities under the federal securities laws, or contribute to payments that the Underwriter or the Issuer may be required to make in respect thereof.

J.P. Morgan Securities LLC (or its affiliates), the Underwriter of the Bonds, serves as the auction broker-dealer for the 2000 Bonds and owns a substantial portion of the 2000 Bonds that will be refunded with the proceeds of the Bonds.

J.P. Morgan Securities LLC and its affiliates together comprise a full service financial institution engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. Such activities may involve or relate to assets, securities and/or instruments of the Issuer and/or the Company or its affiliates (whether directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with (or that are otherwise involved with transactions by) the Issuer and/or the Company. J.P. Morgan Securities LLC and its affiliates may have, from time to time, engaged, and may in the future engage, in transactions with, and performed and may in the future perform, various investment banking services for the Issuer and/or the Company for which they received or will receive customary fees and expenses. Under certain circumstances, J.P. Morgan Securities LLC and its affiliates may have certain creditor and/or other rights against the Issuer and/or the Company and any affiliates thereof in connection with such transactions and/or services. In addition, J.P. Morgan Securities LLC and its affiliates may currently have and may in the future have investment and commercial banking, trust and other relationships with parties that may relate to assets of, or be involved in the issuance of securities and/or instruments by, the Issuer and/or the Company and any affiliates thereof. J.P. Morgan Securities LLC and its affiliates also may communicate independent investment recommendations, market advice or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and at any time may hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

Continuing Disclosure

Because the Bonds will be special and limited obligations of the Issuer, the Issuer is not an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, and does not have any continuing obligations thereunder. Accordingly, the Issuer will not provide any continuing disclosure information with respect to the Bonds or the Issuer.

In order to enable the Underwriter to comply with the requirements of the Rule, the Company will covenant in a continuing disclosure undertaking agreement to be delivered to the Trustee for the benefit of the holders of the Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of the Bonds. Under its Continuing Disclosure Agreement, the Company will covenant to take the following actions:

(i) The Company will provide to the Municipal Securities Rulemaking Board ("MSRB") (in electronic format) (a) annual financial information of the type set forth in Appendix A to this Official Statement (including any information incorporated by reference in Appendix A) and (b) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(ii) The Company will file in a timely manner not in excess of 10 business days after the occurrence of the event with the MSRB notice of the occurrence of any of the following events (if applicable) with respect to the Bonds: (a) principal and interest payment delinquencies; (b) non-payment related defaults, if material; (c) any unscheduled draws on debt service reserves reflecting financial difficulties; (d) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (e) substitution of credit or liquidity providers, or their failure to perform; (f) adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds; (g) modifications to rights of the holders of the Bonds, if material; (b) the giving of notice of optional or unscheduled redemption of any Bonds, if material, and tender offers; (i) defeasance of the Bonds or any portion thereof; (j) release, substitution, or sale of property securing repayment of the Bonds, if material; (k) rating changes; (l) bankruptcy, insolvency, receivership or similar event of the Company; (m) the consummation of a merger, consolidation or acquisition involving the Company, or the sale of all or substantially all of the assets of the Company, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; and (n) appointment of a successor or additional trustee or a change of name of a trustee, if material.

(iii) The Company will file in a timely manner with the MSRB notice of a failure by the Company to file any of the information referred to in paragraph (i) above hy the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit of the holders of the Bonds and shall be enforceable by the holders of those Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indenture, the Loan Agreement or the Bonds.

The Company is a party to continuing disclosure agreements with respect to nine series of pollution control bonds. The MSRB's Electronic Municipal Market Access ("EMMA") website reflects that, within the past five years, for two series of such bonds, the Company's 2011 annual financial statements were timely posted, but to outdated CUSIP numbers. The 2011 annual financial statements were re-posted to the correct CUSIP numbers for those series in May 2012. With respect to both series of bonds, the Company also failed to file on the MSRB's EMMA website in a timely manner a notice of the Company's failure to file such 2011 financial statements in accordance with the applicable continuing disclosure agreements. The Company has subsequently made all of these corrective filings. The Company's 2011 annual financial statements had been filed with the SEC on February 28, 2012. The Company has had, and continues to have, procedures in place in order to make material event notices and financial statement filings on an ongoing basis.

This Official Statement has been duly approved, executed and delivered by the County Judge/Executive of the Issuer, on behalf of the Issuer. However, the Issuer has not and does not assume any responsibility as to the accuracy or completeness of any of the information in this Official Statement except for information furnished by the Issuer under the heading "The Issuer."

COUNTY OF TRIMBLE, KENTUCKY

By: /s/ Jerry L. Powell
County Judge/Executive

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APPENDIX A

THE COMPANY

Louisville Gas and Electric Company (the "Company"), incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of December 31, 2015, the Company provides electric service to approximately 403,000 customers in Louisville and adjacent areas in Kentucky, covering approximately 700 square miles in nine counties and provides natural gas service to approximately 322,000 customers in its electric service area and eight additional counties in Kentucky. The Company's coal-fired electric generating stations, all equipped with systems to reduce sulphur dioxide emissions, produce most of the Company's electricity. The remainder is generated by a natural gas combined cycle combustion turbine, a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help the Company provide economical and reliable natural gas service to customers.

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's affiliate, Kentucky Utilities Company ("KU"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of KU, PPL Corporation or the Company's other affiliates will be obligated to make any payment on the Loan Agreement or the Bonds.

The Company's executive offices are located at 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

The information above concerning the Company is only a summary and does not purport to be comprehensive. Additional information regarding the Company, including audited financial statements, is available in the documents listed under the heading "Documents Incorporated by Reference," which documents are incorporated by reference herein.

Selected Financial Data
(Dollars in millions)

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Operating revenues	$ 709	$ 770	$ 1,444	$ 1,533	$ 1,410
Operating income	$ 195	$ 171	$ 362	$ 324	$ 293
Net income	$ 96	$ 88	$ 185	$ 169	$ 163
Total assets[1]	$ 6,157	$ 5,721	$ 6,068	$ 5,654	$ 4,923
Long-term debt obligations (including amounts due within one year)[1]	$ 1,642	$ 1,346	$ 1,642	$ 1,345	$ 1,345
Ratio of earnings to fixed charges[2]	5.2	6.1	5.9	6.3	8.1

Capitalization:

	June 30, 2016	% of Capitalization
Long-term debt and notes payable	$ 1,752	42%
Common equity	2,412	58%
Total capitalization	$ 4,164	100%

(1) Effective December 31, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of debt issuance costs. The guidance requires certain debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying amount of the associated debt liability. As a result, all periods reported in the December 31, 2015 Form 10-K reflected the retrospective adoption of this guidance. Amounts reported in the table above for June 30, 2015 and December 31, 2013, also reflect retrospective reclassifications from other noncurrent assets to long-term debt of $7 million and $8 million, respectively.

Additionally, effective October 1, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of deferred taxes which requires that deferred tax assets and deferred tax liabilities be classified as noncurrent on the balance sheet. As a result, all periods reported in the December 31, 2015 Form 10-K reflected the retrospective adoption of this guidance. Amounts reported in the table above for June 30, 2015 and December 31, 2013, also reflect retrospective reclassifications from other current assets to noncurrent deferred tax liabilities of $17 million and $3 million, respectively.

(2) For purposes of this ratio, "Earnings" consist of earnings (as defined below) from continuing operations plus fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense and the portion of rental expense that represents an imputed interest component. Earnings from continuing operations consist of income before taxes and the mark-to-market impact of derivative instruments.

The selected financial data presented above for the three fiscal years ended December 31, 2015, and as of December 31 for each of those years, have been derived from the Company's audited financial statements. The selected financial data presented above for the six months ended June 30, 2016 and 2015 have been derived from the Company's unaudited financial statements for the six months ended June 30, 2016 and 2015. The Company's audited financial statements for the three fiscal years ended December 31, 2015, and as of December 31 for each of those years, are included in the Company's Form 10-K for the year ended December 31, 2015 incorporated by reference herein. The Company's unaudited financial statements for the six months ended June 30, 2016 are included in the Company's Form 10-Q for the quarter ended June 30, 2016 incorporated by reference herein. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-K for the year ended December 31, 2015 and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-Q for the quarter ended June 30, 2016, as well as the Combined Notes to Financial Statements as of December 31, 2015, 2014 and 2013 and the Combined Notes to Condensed Financial Statements (Unaudited) as of June 30, 2016 and December 31, 2015 and for the six-month periods ended June 30, 2016 and 2015, should be read in conjunction with the above information. Ernst & Young LLP audited the Company's financial statements for the three fiscal years ended December 31, 2015.

Risk Factors

Investing in the Bonds involves risk. Please see the risk factors in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, which is incorporated by reference in this Appendix A. Before making an investment decision, you should carefully consider these risks as well as the other information contained or incorporated by reference in this Appendix A. Risks and uncertainties not presently known to the Company or that the Company currently deems immaterial may also impair its business operations, its financial results and the value of the Bonds.

Available Information

The Company is subject to the information requirements of the Securities Exchange Act of 1934, as amended, and, accordingly, files reports and other information with the Securities and Exchange Commission (the "SEC"). Such reports and other information on file can be inspected and copied at the public reference facilities of the SEC, currently at 100 F Street, N.E., Room 1580, Washington, D.C. 20549; or from the SEC's Web Site (http://www.sec.gov). Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

Documents Incorporated by Reference

The following documents, as filed by the Company with the SEC, are incorporated herein by reference:

1. Form 10-K Annual Report of the Company for the year ended December 31, 2015;

2. Form 10-Q Quarterly Reports of the Company for the quarters ended March 31, 2016 and June 30, 2016; and

3. Form 8-K Current Reports filed with the SEC on January 12, 2016, February 3, 2016, and June 17, 2016.

All documents filed by the Company with the SEC pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 subsequent to the date of this Official Statement and prior to the termination of the offering of the Bonds shall be deemed to be incorporated by reference in this Appendix and to be made a part hereof from their respective dates of filing. Any statement contained in a document incorporated or deemed to be incorporated by reference in this Official Statement shall be deemed to be modified or superseded for purposes of this Official Statement to the extent that a statement contained in this Official Statement or in any other subsequently filed document which also is or is deemed to be incorporated by reference in this Official Statement modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Official Statement.

The Company hereby undertakes to provide without charge to each person (including any beneficial owner) to whom a copy of this Official Statement has been delivered, on the written or oral request of any such person, a copy of any or all of the documents referred to above which have been or may be incorporated in this Official Statement by reference, other than certain exhibits to such documents. Requests for such copies should be directed to Treasurer, Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

APPENDIX B

(FORM OF OPINION OF BOND COUNSEL)

____, 2016

Re: **$125,000,000 County of Trimble, Kentucky, Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project)**

We hereby certify that we have examined certified copies of the proceedings of record of the County of Trimble, Kentucky (the "**County**"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project), dated their date of issuance, in the aggregate principal amount of $125,000,000 (the "**2016 Series A Bonds**"). The 2016 Series A Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "**Act**"), for the purpose of providing funds which will be used, with other funds provided by Louisville Gas and Electric Company (the "**Company**") for the current refunding of (i) $83,335,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 2000 Series A (Louisville Gas and Electric Company Project), dated August 9, 2000 (the "**Refunded 2000 Series A Bonds**"), and (ii) $41,665,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 2002 Series A (Louisville Gas and Electric Company Project), dated October 23, 2002 (the "**Refunded 2002 Series A Bonds**", and collectively with the Refunded 2000 Series A Bonds, the "**Refunded Bonds**"), which were issued for the purpose of currently refunding a portion of the costs of construction of air and water pollution control facilities serving certain electric generating units of the Company located in Trimble County, Kentucky (the "**Project**"), as provided by the Act.

The 2016 Series A Bonds mature on September 1, 2044 and bear interest initially at the Weekly Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The 2016 Series A Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner, and upon the terms set forth in the 2016 Series A Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the 2016 Series A Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of September 1, 2016 (the "**Loan Agreement**"), by and between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the 2016 Series A Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Refunded Bonds. The Company has agreed to make loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on, and redemption premium, if any, on the 2016 Series A Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed, and delivered by the County; and that the Loan Agreement is a legal, valid, and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of September 1, 2016 (the "**Indenture**"), by and between the County and U.S. Bank National Association, as trustee (the "**Trustee**"), securing the 2016 Series A Bonds and setting forth the covenants and undertakings of the County in connection with the 2016 Series A Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the 2016 Series A Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed, and delivered by the County; and that the Indenture is a legal, valid, and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the 2016 Series A Bonds have been validly authorized, executed, and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid, and binding special and limited obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The 2016 Series A Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings, and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, (i) interest on the 2016 Series A Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any 2016 Series A Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"); and (ii) interest on the 2016 Series A Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements, and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, among other things, that all of the proceeds of the Refunded 2002 Series C Bonds were used to refinance air and water pollution control facilities qualified for financing under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended, and Section 1312(a) of the Tax Reform Act of 1986. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the 2016 Series A Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with after the issuance of the 2016 Series A Bonds in order that interest on the 2016 Series A Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the 2016 Series A Bonds after the issuance of the 2016 Series A Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the 2016 Series A Bonds. We express no opinion (i) regarding the exclusion of interest on any 2016 Series A Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the 2016 Series A Bonds; or (ii) as to the treatment for purposes of federal income taxation of interest on the 2016 Series A Bonds upon a Determination of Taxability. We are further of the opinion that interest on the 2016 Series A Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the 2016 Series A Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the 2016 Series A Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the 2016 Series A Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the 2016 Series A Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the 2016 Series A Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the 2016 Series A Bonds.

Holders of the 2016 Series A Bonds should be aware that the ownership of the 2016 Series A Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the 2016 Series A Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the 2016 Series A Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the 2016 Series A Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the 2016 Series A Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the 2016 Series A Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of Gerald A. Reynolds, General Counsel, Chief Compliance Officer, and Corporate Secretary of the Company and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. Crystal L. Heinz, County Attorney of Trimble County, Kentucky, and relied upon said opinion with respect to the matters therein. The opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges, or encumbrances on the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the 2016 Series A Bonds or the accuracy or completeness of any statements made in connection with any offer or sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(k)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Public Service Commission Form T (telephone).

Response:

LG&E's most recent FERC Form 1 and KPSC Annual Report for Major Natural Gas Companies for the year ended December 31, 2015, are attached. Please note that by a FERC Order dated July 12, 2007 in FERC Docket No. CP07-232-000, LG&E was granted a Section (7) exemption by the FERC under the Natural Gas Act, and as a part of that exemption LG&E was granted "a waiver of reporting and accounting requirements," which includes the filing of Form 2 with the FERC. In addition, on February 15, 2008, the Public Service Commission issued an order granting LG&E's request to cease the annual filing of the FERC Form 2. In lieu of filing a FERC Form 2 with the Public Service Commission, LG&E was ordered to file a paper copy of the annual report information that it files with the Public Service Commission electronically, and include with such copy a paper copy of the notes to its financial statements that LG&E had previously filed as part of its FERC Form 2.

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

Public Service Commission of Kentucky

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Louisville Gas and Electric Company	End of 2015/Q4

LOUISVILLE GAS AND ELECTRIC COMPANY

PUBLIC SERVICE COMMISSION OF KENTUCKY

PRINCIPAL PAYMENT AND INTEREST INFORMATION FOR THE YEAR ENDING DECEMBER 31, 2015

1. Amount of Principal Payment during calendar year $ 250,000,000

2. Is Principal current? (Yes) ____X_____ (No) __________

3. Is Interest current? (Yes) ____X_____ (No) __________

SERVICES PERFORMED BY INDEPENDENT CERTIFIED PUBLIC ACCOUNTANT

Are your financial statements examined by a Certified Public Accountant?

(Yes) ____X_____ (No) __________

If yes, which service is performed?

Audit ____X____

Compilation _________

Review _________

Please enclose a copy of the accountant's report with annual report.

LOUISVILLE GAS AND ELECTRIC COMPANY
ADDITIONAL INFORMATION TO BE FURNISHED WITH
2015 ANNUAL REPORT

ELECTRIC UTILITIES

Please furnish the following information, for Kentucky Operations only, and attach to your Annual Report:

Number of Rural Customers (Other than Farms)	INFORMATION NOT AVAILABLE
Number of Farms Served (A farm is any agricultural operating unit consisting of 3 acres or more)	INFORMATION NOT AVAILABLE
Number of KWH sold to all Rural Customers	INFORMATION NOT AVAILABLE
Total Revenue from all Rural Customers	INFORMATION NOT AVAILABLE

LINE DATA

Total number of Miles of Wire Energized (Located in Kentucky)	12,087
Total number of Miles of Pole line (Located in Kentucky)	7,301

Name of Counties in which you furnish Electric Service:
(If additional space is required, add additional sheet)

Bullitt, Hardin, Henry, Jefferson, Meade, Oldham, Shelby, Spencer and Trimble

Louisville Gas and Electric Company
Supplemental Electric Information
Revenues, Customers and KWH Sales
For Reporting Year 2015

	Revenues	KWHs Sold	Customers
440 Residential	$ 425,948,298	4,080,624,579	353,419
442 Commercial & Industrial Sales			
Small (or Commercial)	$ 359,004,552	3,746,407,656	42,694
Large (or Industrial)	$ 189,367,016	2,775,814,897	476
444 Public Street & Highway Lighting	$ 3,230,561	19,334,030	659
445 Other Sales to Public Authorities	$ 99,216,038	1,144,848,084	4,123
446 Sales to Railroads and Railways	$ -		-
448 Interdepartmental Sales	$ -	-	-
TOTAL Sales to Ultimate Customers	$ 1,076,766,465	11,767,029,246	401,371
447 Sales for Resale	$ 51,201,789	1,735,184,000	14
TOTAL Sales of Electricity	$ 1,127,968,254	13,502,213,246	401,385

THIS PAGE MUST BE COMPLETED AND RETURNED WITH THE ANNUAL REPORT

LOUISVILLE GAS AND ELECTRIC COMPANY
NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES
SUPPLEMENTAL INFORMATION TO 2015 ANNUAL REPORT

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1.	Payroll Period Ended (Date)	12/31/2015
2.	Total Regular Full-Time Employees	697
3.	Total Part-Time and Temporary Employee	15
4.	Total Employees	712

Additional Requested Information

Utility Name Louisville Gas and Electric Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	6	4	1	5	0

Contact Person T. Eric Raible

Contact Person's E-Mail Address eric.raible@lge-ku.com

Utility's Web Address www.lge-ku.com

Please complete the above information, if it is available.

If there are multiple staff who may be contacts please include their names and e-mail addresses also.

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Louisville Gas and Electric Company	End of 2015/Q4

EY
Building a better working world

Ernst & Young LLP
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400 West Market Street
Louisville, KY 40202

Tel: +1 502 585 1400
Fax: +1 502 584 4221
ey.com

March 23, 2016

Kent Blake
Chief Financial Officer
LG&E & KU Energy LLC
220 West Main Street
Louisville, KY 40202

Dear Mr. Blake,

Enclosed please find copies of our manually signed reports on the regulatory-basis financial statements of Louisville Gas and Electric Company and Kentucky Utilities Company as of December 31, 2015 and 2014, and for the years then ended. Please retain this letter and the enclosures in your files as evidence of our authorization to include the attached reports in the 2015 Annual Form 1 filed with the Federal Energy Regulatory Commission.

If you have any questions regarding the form or use of this report, please call me.

Regards,

Ritu Furlan

Attachment

Report of Independent Auditors

To the Board of Directors and Stockholder of Louisville Gas and Electric Company:

We have audited the accompanying financial statements of Louisville Gas and Electric Company, which comprise the comparative balance sheet as of December 31, 2015 and 2014, and the related statements of income, retained earnings and cash flows for the years then ended and the related notes to the financial statements, included on pages 110 through 123.66 in the Federal Energy Regulatory Commission ("FERC") Form No. 1.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with the financial reporting provisions of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 1; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Louisville Gas and Electric Company at December 31, 2015 and 2014, and its revenue and expenses and its cash flows for the years then ended on the basis of the financial reporting provisions of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 1.

Regulatory Basis of Accounting

As described in Note 1 to the financial statements, the financial statements have been prepared by Louisville Gas and Electric Company on the basis of the financial reporting provisions of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than U.S. generally accepted accounting principles, to meet the requirements of the FERC. Our opinion is not modified with respect to this matter.

Restriction on Use

Our report is intended solely for the information and use of the FERC and is not intended to be and should not be used by anyone other than this specified party.

Ernst & Young LLP

Louisville, Kentucky
March 23, 2016

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Louisville Gas and Electric Company	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 220 West Main Street, Louisville, KY 40202	
05 Name of Contact Person T. Eric Raible	06 Title of Contact Person Mgr-Regulatory Acct & Report
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 West Main Street, Louisville, KY 40202	

08 Telephone of Contact Person, *Including Area Code* (502) 627-3426	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Kent W. Blake 02 Title Chief Financial Officer	03 Signature Kent W. Blake	04 Date Signed *(Mo, Da, Yr)* 03/23/2016

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	None
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	None
66	Generating Plant Statistics Pages	410-411	None

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [X] No annual report to stockholders is prepared		

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2015/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Kent W. Blake, Chief Financial Officer
220 West Main Street
Louisville, KY 40202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky July 2, 1913

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnishes electric and natural gas services in Metro Louisville and adjacent territory in Kentucky.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2015/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Louisville Gas and Electric Company (LG&E) is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE). LKE is a wholly-owned subsidiary of PPL Corporation (PPL), based in Allentown, PA.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	CURRENT OFFICERS AT DECEMBER 31, 2015		
2			
3	Chairman of the Board, Chief Executive Officer and		
4	President	Victor A. Staffieri	
5	General Counsel, Chief Compliance Officer and		
6	Corporate Secretary	Gerald A. Reynolds	
7	Chief Financial Officer	Kent W. Blake	
8	Chief Operating Officer	Paul W. Thompson	
9	Senior Vice President-Human Resources	Paula H. Pottinger	
10			
11	FORMER OFFICER DURING 2015		
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13	Chief Administrative Officer	S. Bradford Rives	
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 104 Line No.: 4 Column: c

Officers are employed by LG&E and KU Services Company. Amounts shown reflect the portion of their salary allocated to LG&E.

Schedule Page: 104 Line No.: 9 Column: b

Paula H. Pottinger, Senior Vice President-Human Resources, retired April 1, 2016. Gregory J. Meiman was named Vice President-Human Resources, effective February 1, 2016.

Schedule Page: 104 Line No.: 13 Column: b

S. Bradford Rives, Chief Administrative Officer, retired, effective March 13, 2015, and was not replaced.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	CURRENT BOARD OF DIRECTORS AT DECEMBER 31, 2015	
2		
3	Victor A. Staffieri, Chairman of the Board, Chief Executive	
4	Officer and President	220 West Main Street, Louisville, KY 40202
5	Paul W. Thompson, Chief Operating Officer	220 West Main Street, Louisville, KY 40202
6	Kent W. Blake, Chief Financial Officer	220 West Main Street, Louisville, KY 40202
7	Vincent Sorgi, Senior Vice President and	
8	Chief Financial Officer of PPL	2 North Ninth Street, Allentown, PA 18101
9	William H. Spence, Chairman, President and	
10	Chief Executive Officer of PPL	2 North Ninth Street, Allentown, PA 18101
11		
12	FORMER DIRECTOR DURING 2015	
13		
14	S. Bradford Rives, Chief Administrative Officer	220 West Main Street, Louisville, KY 40202
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Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 6 Column: a
Kent W. Blake, Chief Financial Officer, was appointed to the Board of Directors effective March 25, 2015.

Schedule Page: 105 Line No.: 14 Column: a
S. Bradford Rives, Chief Administrative Officer, announced his retirement, effective March 13, 2015.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Open Access Transmission Tariff (OATT)	
2	Attachment O	Docket No. ER11-2955
3		
4	OATT Schedule 1	Docket No. ER10-1509
5		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1				
2	Page 3 of 5	Schedule 10	3	1
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 1062 Line No.: 2 Column: b

Transmission Operation and Maintenance expenses exclude the amortization of certain regulatory assets approved by the KPSC only.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. On June 23, 2015, LG&E and KU completed an early termination and repurchase transaction under an existing joint lease regarding two 146 MW combustion turbine generating units located at the E.W. Brown Station (Brown Units 6 & 7) operated and maintained by LG&E and KU. The early termination and repurchase transaction occurred pursuant to provisions in such lease. LG&E and KU received FERC authorization in FERC Docket No. EC15-78-000. Per Docket No. EC15-78-000, the termination and repurchase transaction did not involve any accounting entries for LG&E.

4. None of a material nature.

5. None.

6. LG&E received FERC authorization in FERC Docket No. ES15-67-000 for up to $500 million in the form of money pool debt, commercial paper or any other type of short-term loan through November 30, 2017. LG&E's money pool balance was zero at December 31, 2015, and December 31, 2014. LG&E's commercial paper program limit is $350 million as of April 30, 2013. As of December 31, 2015, and December 31, 2014, the outstanding commercial paper balance is $142 million and $264 million, respectively.

   On September 28, 2015, LG&E issued $550 million of first mortgage bonds of which $300 million was issued at an interest rate of 3.30% and will be due October 1, 2025, and $250 million was issued at an interest rate of 4.375% and will be due October 1, 2045. These bonds were issued pursuant to a Kentucky Public Service Commission Order in Case No. 2014-00089 dated June 16, 2014, and amended July 1, 2014.

   LG&E has a revolving credit facility totaling $500 million. The facility was approved by the Kentucky Public Service Commission Order, Case No. 2010-00205 on September 30, 2010. There were no borrowings outstanding under this facility at December 31, 2015, and December 31, 2014. On January 29, 2016, LG&E amended this revolving credit facility to extend the termination date from July 28, 2019, to December 31, 2020. The extension was approved by the Kentucky Public Service Commission Order, Case No. 2015-00138 on July 2, 2015.

7. None.

8. During the first quarter of 2015, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. As outlined in the IBEW Local 2100 contract, union employees received a negotiated 2.5% wage increase effective November 9, 2015.

9. See Notes 4 and 10 of Notes to Financial Statements on page 123.

10. None.

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

11. N/A

12. See Notes to Financial Statements on page 123.

13. On January 15, 2015, S. Bradford Rives, Chief Administrative Officer and a member of the Board of Directors, announced his retirement, effective March 13, 2015. Kent W. Blake, Chief Financial Officer, was appointed to the Board of Directors effective March 25, 2015.

    On November 9, 2015, Michael S. Beer, Vice President-Federal Regulation and Policy, announced his retirement effective December 31, 2015.

    On December 14, 2015, Paul Gregory Thomas, Vice President-Electric Distribution, announced his retirement effective March 1, 2016, and John K. Wolfe was named Vice President-Electric Distribution effective March 1, 2016.

    On December 29, 2015, Edwin R. Staton, Vice President-State Regulation and Rates, announced his retirement effective February 1, 2016, and Robert M. Conroy was named Vice President-State Regulation and Rates effective February 1, 2016.

    On February 1, 2016, Paula H. Pottinger, Senior Vice President-Human Resources, announced her retirement effective April 1, 2016, and Gregory J. Meiman was named Vice President-Human Resources effective February 1, 2016.

14. LG&E is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	6,131,439,950	5,704,302,005
3	Construction Work in Progress (107)	200-201	389,846,496	676,320,025
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,521,286,446	6,380,622,030
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,015,937,460	2,416,826,220
6	Net Utility Plant (Enter Total of line 4 less 5)		4,505,348,986	3,963,795,810
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,505,348,986	3,963,795,810
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		2,139,990	2,139,990
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		630,897	631,414
19	(Less) Accum. Prov. for Depr. and Amort. (122)		63,362	63,362
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	594,286	594,286
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		9,111,614	20,873,650
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		10,273,435	22,035,988
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,729,674	4,451,872
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		19,790	19,790
38	Temporary Cash Investments (136)		16,031,632	5,476,948
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		92,825,949	108,131,455
41	Other Accounts Receivable (143)		6,816,857	10,133,997
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,184,712	1,594,049
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		16,375,434	97,209,024
45	Fuel Stock (151)	227	71,040,238	66,567,149
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	32,048,293	35,430,432
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	159	6,329

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) / /	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	5,546,728	6,352,862
55	Gas Stored Underground - Current (164.1)		42,068,559	54,151,379
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		6,472,537	7,636,886
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		2,497	8,727
60	Rents Receivable (172)		456,414	781,782
61	Accrued Utility Revenues (173)		67,041,506	76,374,353
62	Miscellaneous Current and Accrued Assets (174)		412	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		358,291,967	471,138,936
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,519,246	10,484,102
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	436,775,786	413,300,917
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,012,217	3,024,273
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	458,589,969	480,468,887
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	26,435	0
81	Unamortized Loss on Reaquired Debt (189)		16,863,862	18,031,262
82	Accumulated Deferred Income Taxes (190)	234	286,542,027	192,524,444
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,216,329,542	1,117,833,885
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,092,383,920	5,576,944,609

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 110 Line No.: 69 Column: c

Unamortized Debt Expenses (181) Without Purchase Accounting	$	15,881,935
Purchase Accounting Adjustment		(2,362,689)
Total for Unamortized Debt Expenses (181)	$	13,519,246

Schedule Page: 110 Line No.: 69 Column: d

Unamortized Debt Expenses (181) Without Purchase Accounting	$	12,997,480
Purchase Accounting Adjustment		(2,513,378)
Total for Unamortized Debt Expenses (181)	$	10,484,102

Schedule Page: 110 Line No.: 72 Column: c

Other Regulatory Assets (182.3) Without Purchase Accounting	$	434,413,097
Purchase Accounting Adjustment		2,362,689
Total for Other Regulatory Assets (182.3)	$	436,775,786

Schedule Page: 110 Line No.: 72 Column: d

Other Regulatory Assets (182.3) Without Purchase Accounting	$	410,620,298
Purchase Accounting Adjustment		2,680,619
Total for Other Regulatory Assets (182.3)	$	413,300,917

Schedule Page: 110 Line No.: 78 Column: c

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	2,547,166
Purchase Accounting Adjustment		456,042,803
Total for Miscellaneous Deferred Debits (186)	$	458,589,969

Schedule Page: 110 Line No.: 78 Column: d

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	727,943
Purchase Accounting Adjustment		479,740,944
Total for Miscellaneous Deferred Debits (186)	$	480,468,887

Schedule Page: 110 Line No.: 82 Column: c

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	261,142,312
Purchase Accounting Adjustment		25,399,715
Total for Accumulated Deferred Income Taxes (190)	$	286,542,027

Schedule Page: 110 Line No.: 82 Column: d

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	157,876,610
Purchase Accounting Adjustment		34,647,834
Total for Accumulated Deferred Income Taxes (190)	$	192,524,444

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(mo, da, yr)* / /	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	425,170,424	425,170,424
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,611,167,368	1,521,167,368
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	835,889	835,889
11	Retained Earnings (215, 215.1, 216)	118-119	294,897,774	228,533,983
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		2,330,399,677	2,174,035,886
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,659,304,000	1,359,304,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	-1,590,554	-1,681,852
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,574,532	4,560,414
24	Total Long-Term Debt (lines 18 through 23)		1,653,138,914	1,353,061,734
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		4,249,578	4,272,805
29	Accumulated Provision for Pensions and Benefits (228.3)		132,307,531	142,374,775
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		41,869,775	43,146,203
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		189,099,815	85,375,725
35	Total Other Noncurrent Liabilities (lines 26 through 34)		367,526,699	275,169,508
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		141,969,180	263,956,483
38	Accounts Payable (232)		172,152,826	245,177,038
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		24,563,440	20,016,016
41	Customer Deposits (235)		25,405,488	24,498,183
42	Taxes Accrued (236)	262-263	19,925,519	18,869,565
43	Interest Accrued (237)		10,946,603	5,870,903
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,516,387	2,001,512
48	Miscellaneous Current and Accrued Liabilities (242)		21,396,264	24,288,849
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		47,145,364	47,988,828
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		41,869,775	43,146,203
52	Derivative Instrument Liabilities - Hedges (245)		0	33,263,681
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		423,151,296	642,784,855
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		7,428,646	8,234,051
57	Accumulated Deferred Investment Tax Credits (255)	266-267	34,643,471	35,982,105
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	4,017,629	14,776,604
60	Other Regulatory Liabilities (254)	278	156,432,731	180,068,801
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		938,677,671	711,166,634
64	Accum. Deferred Income Taxes-Other (283)		176,967,186	181,664,431
65	Total Deferred Credits (lines 56 through 64)		1,318,167,334	1,131,892,626
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,092,383,920	5,576,944,609

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 7 Column: c

Other Paid-In Capital (208-211) Without Purchase Accounting	$ 417,081,499
Purchase Accounting Adjustment	1,194,085,869
Total for Other Paid-In Capital (208-211)	$ 1,611,167,368

Schedule Page: 112 Line No.: 7 Column: d

Other Paid-In Capital (208-211) Without Purchase Accounting	$ 327,081,499
Purchase Accounting Adjustment	1,194,085,869
Total for Other Paid-In Capital (208-211)	$ 1,521,167,368

Schedule Page: 112 Line No.: 11 Column: c

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 1,098,854,463
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000	(808,946,891)
Amortization of Purchase Accounting Adjustments - (net of deferred taxes of $3,177,068)	4,990,203
Rounding	(1)
Total for Retained Earnings (215, 215.1, 216)	$ 294,897,774

As of December 31, 2015, in compliance with Docket No. EL12-27-000, the amount in the Company's equity accounts available to be paid in the form of dividends is as follows:

Retained Earnings as of 12/31/2015 -- sum of lines 11 & 12 on page 112 (Retained Earnings and Unappropriated Undistributed Subsidiary Earnings)	$ 294,897,774
Add: Stated capital account, reflecting pre-acquisition retained earnings less dividends applied to the account -- tracked in a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In Capital)	808,946,891
Add: Net after-tax losses attributable to amortization of pushdown accounting net assets and liabilities and impairment, if any, cumulative -- tracked on a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In-Capital)	(4,990,203)
Rounding	1
Retained earnings as of 12/31/2015, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$ 1,098,854,463
Retained earnings prior to the 11/1/2010 acquisition	808,946,891
Cumulative post-acquisition net income	778,407,572
Cumulative post-acquisition dividends	(488,500,000)
Retained earnings as of 12/31/2015, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$ 1,098,854,463

Schedule Page: 112 Line No.: 11 Column: d

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$ 1,032,434,889
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000	(808,946,891)
Amortization of Purchase Accounting Adjustment - (net of deferred taxes of $3,212,584)	5,045,986
Rounding	(1)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Total for Retained Earnings (215, 215.1, 216)	$ 228,533,983

As of December 31, 2014, in compliance with Docket No. EL12-27-000, the amount in the Company's equity accounts available to be paid in the form of dividends is as follows:

Retained Earnings as of 12/31/2014 -- sum of lines 11 & 12 on page 112 (Retained Earnings and Unappropriated Undistributed Subsidiary Earnings)	$ 228,533,983
Add: Stated capital account, reflecting pre-acquisition retained earnings less dividends applied to the account -- tracked in a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In Capital)	808,946,891
Add: Net after-tax losses attributable to amortization of pushdown accounting net assets and liabilities and impairment, if any, cumulative -- tracked on a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In-Capital)	(5,045,986)
Rounding	1
Retained earnings as of 12/31/2014, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$ 1,032,434,889
Retained earnings prior to the 11/1/2010 acquisition	808,946,891
Cumulative post-acquisition net income	592,987,998
Cumulative post-acquisition dividends	(369,500,000)
Retained earnings as of 12/31/2014, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$ 1,032,434,889

Schedule Page: 112 Line No.: 21 Column: c

Fair value of bonds recorded in purchase accounting was eliminated during the fourth quarter of 2013 related to remarketed bonds, leaving one bond with a negative fair market value.

Other Long-Term Debt (224) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	(1,590,554)
Total for Other Long-Term Debt (224)	$ (1,590,554)

Schedule Page: 112 Line No.: 21 Column: d

Fair value of bonds recorded in purchase accounting was eliminated during the fourth quarter of 2013 related to remarketed bonds, leaving one bond with a negative fair market value.

Other Long-Term Debt (224) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	(1,681,852)
Total for Other Long-Term Debt (224)	$ (1,681,852)

Schedule Page: 112 Line No.: 59 Column: c

Other Deferred Credits (253) Without Purchase Accounting	$ 4,017,629
Purchase Accounting Adjustment	-
Total for Other Deferred Credits (253)	$ 4,017,629

Schedule Page: 112 Line No.: 59 Column: d

Other Deferred Credits (253) Without Purchase Accounting	$ 14,609,363
Purchase Accounting Adjustment	167,241

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Total for Other Deferred Credits (253)	$	14,776,604

Schedule Page: 112 Line No.: 60 Column: c

Other Regulatory Liabilities (254) Without Purchase Accounting	$	89,547,280
Purchase Accounting Adjustment		66,885,451
Total for Other Regulatory Liabilities (254)	$	156,432,731

Schedule Page: 112 Line No.: 60 Column: d

Other Regulatory Liabilities (254) Without Purchase Accounting	$	89,485,209
Purchase Accounting Adjustment		90,583,592
Total for Other Regulatory Liabilities (254)	$	180,068,801

Schedule Page: 112 Line No.: 64 Column: c

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	150,948,746
Purchase Accounting Adjustment		26,018,440
Total for Accumulated Deferred Income Taxes - Other (283)	$	176,967,186

Schedule Page: 112 Line No.: 64 Column: d

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	146,362,357
Purchase Accounting Adjustment		35,302,074
Total for Accumulated Deferred Income Taxes - Other (283)	$	181,664,431

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,465,598,747	1,537,927,386		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	790,731,677	911,715,538		
5	Maintenance Expenses (402)	320-323	114,048,758	111,790,202		
6	Depreciation Expense (403)	336-337	151,308,951	147,126,109		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	10,664,307	9,488,709		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	37,400,047	34,200,411		
15	Income Taxes - Federal (409.1)	262-263	-13,679,235	-24,215,205		
16	- Other (409.1)	262-263	3,659,700	9,909,706		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	447,741,617	298,118,539		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	320,258,358	178,198,376		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,338,634	-1,788,780		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		122	427		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,220,278,708	1,318,146,426		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		245,320,039	219,780,960		

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,146,077,403	1,177,644,420	319,521,344	360,282,966			2
						3
595,450,826	669,509,421	195,280,851	242,206,117			4
94,604,630	92,657,579	19,444,128	19,132,623			5
122,203,833	120,386,794	29,105,118	26,739,315			6
						7
7,464,986	6,642,068	3,199,321	2,846,641			8
						9
						10
						11
						12
						13
28,340,155	26,115,113	9,059,892	8,085,298			14
-12,314,375	-4,120,938	-1,364,860	-20,094,267			15
1,867,677	9,810,528	1,792,023	99,178			16
366,455,672	221,707,202	81,285,945	76,411,337			17
259,277,427	141,833,902	60,980,931	36,364,474			18
-1,260,914	-1,691,460	-77,720	-97,320			19
						20
						21
122	427					22
						23
						24
943,534,941	999,181,978	276,743,767	318,964,448			25
202,542,462	178,462,442	42,777,577	41,318,518			26

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		245,320,039	219,780,960		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		6,285	39,286		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,207	6,842		
33	Revenues From Nonutility Operations (417)		1,393,587	1,429,857		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		68,155	44,207		
38	Allowance for Other Funds Used During Construction (419.1)					
39	Miscellaneous Nonoperating Income (421)		-9,045	-4,390		
40	Gain on Disposition of Property (421.1)		165,839	6,852		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		1,622,614	1,508,970		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		15,141	217,416		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,972,151	2,919,777		
46	Life Insurance (426.2)					
47	Penalties (426.3)		6,570	-31,230		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		570,732	819,750		
49	Other Deductions (426.5)		2,451,011	1,370,911		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,015,605	5,296,624		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	7,003	6,710		
53	Income Taxes-Federal (409.2)	262-263	-1,834,650	-1,079,880		
54	Income Taxes-Other (409.2)	262-263	-334,587	-196,938		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	230,967	1,257		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	42,045	24,548		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,973,312	-1,293,399		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-3,419,679	-2,494,255		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		50,809,850	44,283,072		
63	Amort. of Debt Disc. and Expense (428)		2,470,268	2,310,317		
64	Amortization of Loss on Reaquired Debt (428.1)		1,167,401	1,106,947		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		5,661	5,761		
68	Other Interest Expense (431)		2,083,390	1,504,616		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)					
70	Net Interest Charges (Total of lines 62 thru 69)		56,536,570	49,210,713		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		185,363,790	168,075,992		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		185,363,790	168,075,992		

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 17 Column: c

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	437,453,720
Amortization of Purchase Accounting Adjustment		10,287,897
Total for Provision for Deferred Income Taxes (410.1)	$	447,741,617

Schedule Page: 114 Line No.: 17 Column: d

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	287,926,981
Amortization of Purchase Accounting Adjustment		10,191,558
Total for Provision for Deferred Income Taxes (410.1)	$	298,118,539

Schedule Page: 114 Line No.: 17 Column: g

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	356,168,168
Amortization of Purchase Accounting Adjustment		10,287,504
Total for Provision for Deferred Income Taxes (410.1)	$	366,455,672

Schedule Page: 114 Line No.: 17 Column: h

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	211,516,702
Amortization of Purchase Accounting Adjustment		10,190,500
Total for Provision for Deferred Income Taxes (410.1)	$	221,707,202

Schedule Page: 114 Line No.: 17 Column: i

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	81,285,552
Amortization of Purchase Accounting Adjustment		393
Total for Provision for Deferred Income Taxes (410.1)	$	81,285,945

Schedule Page: 114 Line No.: 17 Column: j

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	76,410,279
Amortization of Purchase Accounting Adjustment		1,058
Total for Provision for Deferred Income Taxes (410.1)	$	76,411,337

Schedule Page: 114 Line No.: 18 Column: c

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	309,934,946
Amortization of Purchase Accounting Adjustment		10,323,412
Total for Provision for Deferred Income Taxes (411.1)	$	320,258,358

Schedule Page: 114 Line No.: 18 Column: d

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	167,971,192
Amortization of Purchase Accounting Adjustment		10,227,184
Total for Provision for Deferred Income Taxes (411.1)	$	178,198,376

Schedule Page: 114 Line No.: 18 Column: g

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	248,961,688
Amortization of Purchase Accounting Adjustment		10,315,739
Total for Provision for Deferred Income Taxes (411.1)	$	259,277,427

Schedule Page: 114 Line No.: 18 Column: h

Provision for Deferred Income Taxes (411.1) Without Purchase

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Accounting	$	131,615,078
Amortization of Purchase Accounting Adjustment		10,218,824
Total for Provision for Deferred Income Taxes (411.1)	$	141,833,902

Schedule Page: 114 Line No.: 18 Column: i

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	60,973,258
Amortization of Purchase Accounting Adjustment		7,673
Total for Provision for Deferred Income Taxes (411.1)	$	60,980,931

Schedule Page: 114 Line No.: 18 Column: j

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	36,356,114
Amortization of Purchase Accounting Adjustment		8,360
Total for Provision for Deferred Income Taxes (411.1)	$	36,364,474

Schedule Page: 114 Line No.: 62 Column: c

Interest on Long-Term Debt (427) Without Purchase Accounting	$	50,718,552
Amortization of Purchase Accounting Adjustment		91,298
Total for Interest on Long-Term Debt (427)	$	50,809,850

Schedule Page: 114 Line No.: 62 Column: d

Interest on Long-Term Debt (427) Without Purchase Accounting	$	44,191,488
Amortization of Purchase Accounting Adjustment		91,584
Total for Interest on Long-Term Debt (427)	$	44,283,072

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		228,533,983	172,457,991
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Rounding		1	
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		1	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		185,363,790	168,075,992
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Without Par Value		-119,000,000	(112,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-119,000,000	(112,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		294,897,774	228,533,983
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		294,897,774	228,533,983
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 118 Line No.: 48 Column: c

See footnote data detail on Schedule Page: 112, Line No.: 11, Column: c.

Schedule Page: 118 Line No.: 48 Column: d

See footnote data detail on Schedule Page: 112, Line No.: 11, Column: d.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	185,363,790	168,075,992
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	151,308,951	147,126,109
5	Amortization of Plant	10,664,307	9,488,709
6			
7			
8	Deferred Income Taxes (Net)	128,831,722	121,839,749
9	Investment Tax Credit Adjustment (Net)	-1,338,634	-1,788,780
10	Net (Increase) Decrease in Receivables	106,245,846	-100,200,999
11	Net (Increase) Decrease in Inventory	3,632,318	-8,759,600
12	Net (Increase) Decrease in Allowances Inventory	6,170	35,410
13	Net Increase (Decrease) in Payables and Accrued Expenses	2,314,964	71,086,537
14	Net (Increase) Decrease in Other Regulatory Assets	-23,792,799	-97,963,505
15	Net Increase (Decrease) in Other Regulatory Liabilities	62,071	-3,078,959
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	35,291,004	68,886,345
19	Change in Other Deferred Debits	231,892	-2,002,270
20	Change in Other Deferred Credits	-874,256	-2,361,167
21	Interest Rate Swaps Settlement	-43,688,302	
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	554,259,044	370,383,571
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-647,110,962	-619,601,565
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-20,729,273	-21,097,639
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):	-21,411,936	-14,865,005
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-689,252,171	-655,564,209
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	194,454	19,756
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-689,057,717	-655,544,453
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	294,631,159	-2,392,642
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		244,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	294,631,159	241,607,358
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	90,000,000	157,500,000
77			
78	Net Decrease in Short-Term Debt (c)	-122,000,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-119,000,000	-112,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	143,631,159	287,107,358
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	8,832,486	1,946,476
87			
88	Cash and Cash Equivalents at Beginning of Period	9,948,610	8,002,134
89			
90	Cash and Cash Equivalents at End of period	18,781,096	9,948,610

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Other changes in Net Utility Plant	$	(74,410,719)
Accumulated Provision for Uncollectible Accounts - Debit		2,492,068
Amortization of Debt Expenses and Losses on Bonds		3,315,287
Unamortized Discount on Long-Term Debt - Debit		322,382
Unamortized Discount on Short-Term Debt - Debit		12,697
Net decrease in Prepayments and Other Assets		9,477,299
Net increase in Preliminary Survey		(1,602,767)
Net decrease in Customer Advances for Construction		(805,405)
Net increase in Asset Retirement Obligations		103,724,089
Net decrease in Collateral Cash		11,762,036
Net increase in the Provision for Pension and Postretirement Benefits		11,574,764
Pension and Postretirement Funding		(26,538,500)
Net increase in Other Liabilities		944,216
Reserve for Depreciation		(5,032,226)
Change in Deferred Income Taxes - Purchase Accounting		(35,515)
Change in Pollution Control Bonds - Purchase Accounting		91,298
Total	$	35,291,004

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Other operating cash flows:

Other changes in Net Utility Plant	$	5,042,143
Accumulated Provision for Uncollectible Accounts - Debit		4,985,368
Amortization of Debt Expenses and Losses on Bonds		3,772,007
Unamortized Discount on Long-Term Debt - Debit		340,817
Unamortized Discount on Short-Term Debt - Credit		(40,294)
Net increase in Prepayments and Other Assets		(1,803,509)
Net increase in Preliminary Survey		(255,952)
Net increase in Customer Advances for Construction		1,486,026
Net increase in Asset Retirement Obligations		3,179,510
Net decrease in Collateral Cash		1,351,862
Net increase in the Provision for Pension and Postretirement Benefits		56,412,049
Pension and Postretirement Funding		(12,753,900)
Net increase in Other Liabilities		11,755,108
Reserve for Depreciation		(4,640,848)
Change in Deferred Income Taxes - Purchase Accounting		(35,627)
Change in Pollution Control Bonds - Purchase Accounting		91,585
Total	$	68,886,345

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Other plant investing cash flows:

Costs of removal of utility plant	$	(21,411,936)

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Other plant investing cash flows:

Costs of removal of utility plant	$	(14,865,005)

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Other financing cash flows:

LG&E and KU Energy LLC Equity Contribution	$	90,000,000

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FOOTNOTE DATA

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Other financing cash flows:

LG&E and KU Energy LLC Equity Contribution	$	157,500,000

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Cash and cash equivalents are comprised of the following amounts:

Cash (131)	$	2,729,674
Working Fund (135)		19,790
Temporary Cash Investments (136)		16,031,632
Total Cash and Cash Equivalents	$	18,781,096

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Cash and cash equivalents are comprised of the following amounts:

Cash (131)	$	4,451,872
Working Fund (135)		19,790
Temporary Cash Investments (136)		5,476,948
Total Cash and Cash Equivalents	$	9,948,610

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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

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GLOSSARY OF TERMS AND ABBREVIATIONS

KU - Kentucky Utilities Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky.

LG&E - Louisville Gas and Electric Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas in Kentucky.

LKE - LG&E and KU Energy LLC, a subsidiary of PPL and the parent of LG&E, KU and other subsidiaries.

LKS - LG&E and KU Services Company, a subsidiary of LKE that provides services to LKE and its subsidiaries.

PPL - PPL Corporation, the parent holding company of PPL Services, LKE and other subsidiaries.

PPL Services - PPL Services Corporation, a subsidiary of PPL that provides administrative, management and support services to PPL and its subsidiaries.

Other terms and abbreviations

401(h) account(s) - A sub account established within a qualified pension trust to provide for the payment of retiree medical costs.

AFUDC - Allowance for Funds Used During Construction. The cost of equity and debt funds used to finance construction projects of regulated businesses, which is capitalized as part of construction costs.

ARO - asset retirement obligation.

BSER - Best System of Emission Reduction. The degree of emission reduction that EPA determines has been adequately demonstrated when taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements.

Cane Run Unit 7 - a natural gas combined-cycle generating unit in Kentucky, jointly owned by LG&E and KU, with a capacity of 642 MW (141 MW and 501 MW to LG&E and KU).

CCR(s) - Coal Combustion Residual(s). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes.

Clean Air Act - federal legislation enacted to address certain environmental issues related to air emissions, including acid rain, ozone and toxic air emissions.

Clean Water Act - federal legislation enacted to address certain environmental issues relating to water quality including effluent discharges, cooling water intake, and dredge and fill activities.

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CPCN - Certificate of Public Convenience and Necessity. Authority granted by the KPSC pursuant to Kentucky Revised Statute 278.020 to provide utility service to or for the public or the construction of certain plant, equipment, property or facility for furnishing of utility service to the public.

DSM - Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM plans proposed by any utility under its jurisdiction. Proposed DSM mechanisms may seek full recovery of costs and revenues lost by implementing DSM programs and/or incentives designed to provide financial rewards to the utility for implementing cost-effective DSM programs. The cost of such programs shall be assigned only to the class or classes of customers which benefit from the programs.

EBPB - Employee Benefit Plan Board. The administrator of PPL's U.S. qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

ECR - Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, Kentucky electric utilities are entitled to the current recovery of costs of complying with the Clean Air Act, as amended, and those federal, state or local environmental requirements that apply to coal combustion wastes and by-products from the production of energy from coal.

ELG(s) - Effluent Limitation Guidelines, regulations promulgated by the EPA.

EPA - Environmental Protection Agency, a U.S. government agency.

FERC - Federal Energy Regulatory Commission, the U.S. federal agency that regulates, among other things, interstate transmission and wholesale sales of electricity, hydroelectric power projects and related matters.

GAAP - Generally Accepted Accounting Principles in the U.S.

GHG - greenhouse gas(es).

GLT - Gas Line Tracker. The KPSC approved mechanism for LG&E's recovery of costs associated with gas service lines, gas risers, leak mitigation, and gas main replacements. Rate recovery became effective January 1, 2013.

KPSC - Kentucky Public Service Commission, the state agency that has jurisdiction over the regulation of rates and service of utilities in Kentucky.

kWh - kilowatt hour, basic unit of electrical energy.

LG&E 2010 Mortgage Indenture - LG&E's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as supplemented.

LIBOR - London Interbank Offered Rate.

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MATS - Mercury and Air Toxics Standards, regulations promulgated by the EPA.

MW - megawatt, one thousand kilowatts.

NAAQS - National Ambient Air Quality Standards periodically adopted pursuant to the Clean Air Act.

NERC - North American Electric Reliability Corporation.

NGCC - Natural gas-fired combined-cycle generating plant.

NPNS - the normal purchases and normal sales exception as permitted by derivative accounting rules. Derivatives that qualify for this exception may receive accrual accounting treatment.

NSR - The new source review provisions of the Clean Air Act that impose stringent emission control requirements on new and modified sources of air emissions that result in emission increases beyond thresholds allowed by the Clean Air Act.

OCI - other comprehensive income or loss.

OVEC - Ohio Valley Electric Corporation, located in Piketon, Ohio, an entity in which LKE indirectly owns an 8.13% interest (consists of LG&E's 5.63% and KU's 2.50% interests), which is accounted for as a cost-method investment. OVEC owns and operates two coal-fired power plants, the Kyger Creek plant in Ohio and the Clifty Creek plant in Indiana, with combined summer rating capacities of 2,120 MW.

PP&E - property, plant and equipment.

RCRA - Resource Conservation and Recovery Act of 1976.

RFC - Reliability*First* Corporation, one of eight regional entities with delegated authority from NERC that work to safeguard the reliability of the bulk power systems throughout North America.

SCRs - selective catalytic reduction, a pollution control process for the removal of nitrogen oxide from exhaust gas.

Scrubber - an air pollution control device that can remove particulates and/or gases (primarily sulfur dioxide) from exhaust gases.

SEC - the U.S. Securities and Exchange Commission, a U.S. government agency primarily responsible to protect investors and maintain the integrity of the securities markets.

SERC - SERC Reliability Corporation, one of eight regional entities with delegated authority from NERC that work to safeguard the reliability of the bulk power systems throughout North America.

Superfund - federal environmental statute that addresses remediation of contaminated sites; states also have

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similar statues.

VEBA - Voluntary Employee Benefit Association Trust, accounts for health and welfare plans for future benefit payments for employees, retirees or their beneficiaries.

Volumetric risk - the risk that the actual load volumes provided under full-requirement sales contracts could vary significantly from forecasted volumes.

As permitted by the FERC for the Year Ended December 31, 2015 Form 1, the Notes to Financial Statements set forth below are principally from the Respondent's SEC Form 10-K for the Year Ended December 31, 2015, which was filed with the SEC on February 19, 2016. Accordingly, these Notes do not reflect updated information since this filing date.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

Capitalized terms and abbreviations appearing in the notes to financial statements are defined in the glossary. Dollars are in millions unless otherwise noted.

Presentation

The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than GAAP. The significant differences between GAAP and FERC reporting are as follows:

(a) Certain cost of removal obligations are recorded in accumulated depreciation for FERC reporting and recorded in regulatory liabilities for GAAP reporting;
(b) Long-term and short-term bonds are recorded in total in the long-term debt section for FERC reporting and are presented separately in current liabilities for the short-term portion and in long-term debt for the long-term portion for GAAP reporting;
(c) Deferred taxes are shown gross for FERC reporting in the Balance Sheet (a deferred asset and a deferred liability are recorded), but for GAAP reporting the deferred taxes are netted together and recorded as a net asset or net liability;
(d) Utility plant acquired before November 1, 2010 is stated at cost for FERC reporting and was restated to net fair value as of November 1, 2010, for GAAP reporting;
(e) Long-term and short-term regulatory assets are presented together in deferred debits for FERC reporting. For GAAP reporting, short-term regulatory assets are presented in current assets and long-term regulatory assets are presented in other noncurrent assets; and
(f) Long-term and short-term regulatory liabilities are presented together in deferred credits for FERC reporting. For GAAP reporting, short-term regulatory liabilities are presented in current liabilities and long-term regulatory liabilities are presented in deferred credits and other noncurrent liabilities.
(g) Deferred financing costs are classified as assets for FERC reporting. For GAAP reporting, such costs are classified as contra-liabilities and are presented together with long-term debts.

Business and Consolidation

LG&E is engaged in the generation, transmission, distribution and sale of electricity. LG&E also engages in the distribution and sale of natural gas.

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LG&E has no controlling interest in any Variable Interest Entities (VIEs). All other investments are carried at cost or fair value.

LG&E's financial statements include its share of any undivided interests in jointly owned facilities, as well as its share of the related operating costs of those facilities. See Note 9 for additional information.

Regulation

LG&E is a cost-based rate-regulated utility for which rates are set by regulators to enable LG&E to recover the costs of providing electric or gas service and to provide a reasonable return to its shareholder. Base rates are generally established based on a future test period. Regulatory assets are recognized for the effect of transactions or events where future recovery of underlying costs is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise currently be charged to expense. Regulatory liabilities are recognized for amounts expected to be returned through future regulated customer rates. In certain cases, regulatory liabilities are recorded based on an understanding or agreement with the regulator that rates have been set to recover costs that are expected to be incurred in the future, and the regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and regulatory liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC or the applicable state regulatory commissions. See Note 4 for additional details regarding regulatory matters.

Accounting Records

LG&E's system of accounts is maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the applicable state regulatory commissions.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." LG&E continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events. Loss accruals for environmental remediation are discounted when appropriate.

The accrual of contingencies that might result in gains is not recorded, unless realization is assured.

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Changes in Classification

The classification of certain amounts in the 2014 financial statements have been changed to conform to the current presentation. These reclassifications did not affect LG&E's net income or equity.

Price Risk Management

Interest rate contracts are used to hedge exposure to change in the fair value of debt instruments and to hedge exposures to variability in expected cash flows associated with existing floating-rate debt instruments or forecasted fixed-rate issuances of debt. Similar derivatives may receive different accounting treatment, depending on management's intended use and documentation.

Certain contracts may not meet the definition of a derivative because they lack a notional amount or a net settlement provision. In cases where there is no net settlement provision, markets are periodically assessed to determine whether market mechanisms have evolved that would facilitate net settlement. Certain derivative contracts may be excluded from the requirements of derivative accounting treatment because NPNS has been elected. These contracts are accounted for using accrual accounting. Contracts that have been classified as derivative contracts are reflected on the Balance Sheets at fair value. The portion of derivative positions that deliver within a year are included in "Current Assets" and "Current Liabilities," while the portion of derivative positions that deliver beyond a year are recorded in "Other Noncurrent Assets" and "Deferred Credits and Other Noncurrent Liabilities." LG&E considers intra-month transactions to be spot activity, which is not accounted for as a derivative.

Processes exist that allow for subsequent review and validation of the contract information as it relates to interest rate derivatives. The accounting department provides the treasury department with guidelines on appropriate accounting classifications for various contract types and strategies. Examples of accounting guidelines provided to the treasury department staff include, but are not limited to:

- Transactions to lock in an interest rate prior to a debt issuance can be designated as cash flow hedges, to the extent the forecasted debt issuances remain probable of occurring.

- Derivative transactions may be marked to fair value through regulatory assets/liabilities if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps that are included in customer rates.

Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing activities on the Statements of Cash Flows, depending on the classification of the hedged items.

LG&E has elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

See Notes 12 and 13 for additional information on derivatives.

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Revenue

Revenue Recognition

Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all meters being read and bills rendered at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh. Any difference between estimated and actual revenues is adjusted the following month.

Accounts Receivable

Accounts receivable are reported on the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

Accounts receivable collectability is evaluated using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness and economic conditions. Specific events, such as bankruptcies, are also considered. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables and historical and industry trends.

Accounts receivable are written off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when it is known they will be received.

The changes in the allowance for doubtful accounts at December 31 were:

		Additions			
	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
2015	$ 2	$ 2	$ -	$ 3	$ 1
2014	2	5	(1)	4	2

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work in progress.
(b) Primarily related to uncollectible accounts written off.

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Cash

Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered to be cash equivalents.

Fair Value Measurements

LG&E values certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities, investments in securities in defined benefit plans, and cash and cash equivalents. LG&E uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

LG&E classifies fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

• **Level 1** - quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

• **Level 2** - inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.

• **Level 3** - unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, LG&E's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent assets or for the liquidation of long-term debts, are classified as long-term.

Short-term Investments

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in "Short-term investments" ("Other current assets" if not significant) on the Balance Sheets.

Cost Method Investment

LG&E has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the Balance Sheets. LG&E and 11 other electric utilities are equity owners of OVEC. OVEC's power is currently supplied to LG&E and 12 other companies affiliated with the various owners. LG&E owns 5.63% of OVEC's common stock. Pursuant to a power purchase agreement, LG&E is contractually entitled to its ownership percentage of OVEC's output, which is approximately 120 MW.

LG&E's investment in OVEC is not significant. The direct exposure to loss as a result of LG&E's involvement with OVEC is generally limited to the value of its investment; however, LG&E is conditionally responsible for a pro-rata share of certain OVEC obligations. As part of PPL's acquisition of LKE, the value of the power purchase contract was recorded as an intangible asset with an offsetting regulatory liability, both of which are being amortized using the units-of-production method until March 2026, the expiration date of the agreement. See Notes 10 and 14 for additional discussion of the power purchase agreement.

Long-Lived and Intangible Assets

Property, Plant and Equipment

PP&E is recorded at original cost, unless impaired. PP&E acquired in business combinations is recorded at fair value at the time of acquisition, which establishes its original cost. If impaired, the asset is written down to fair value at that time, which becomes the new cost basis of the asset. Original cost for constructed assets includes material, labor, contractor costs, certain overheads and financing costs, where applicable. The cost of repairs and minor replacements are charged to expense as incurred. LG&E records costs associated with planned major maintenance projects in the period in which the costs are incurred. No costs associated with planned major maintenance projects are accrued in advance of the period in which the work is performed. LG&E accrues costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. Cost of removal amounts accrued through depreciation rates are accumulated as a regulatory liability until the removal costs are incurred. See "Asset Retirement Obligations" below and Note 4 for additional information.

LG&E does not record AFUDC as a return is provided on construction work in progress.

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Depreciation

Depreciation is recorded over the estimated useful lives of property using various methods including the straight-line, composite and group methods. When a component of PP&E that was depreciated under the composite or group method is retired, the original cost is charged to accumulated depreciation. When all or a significant portion of an operating unit that was depreciated under the composite or group method is retired or sold, the property and the related accumulated depreciation account is reduced and any gain or loss is included in income, unless otherwise required by regulators. LG&E's weighted-average rates of depreciation for regulated utility plant were 3.65% and 4.05% at December 31, 2015 and 2014.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the purchase price paid over the fair value of the identifiable net assets acquired in a business combination.

Other acquired intangible assets are initially measured based on their fair value. Intangibles that have finite useful lives are amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. Costs incurred to obtain an initial license and renew or extend terms of licenses are capitalized as intangible assets.

When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, LG&E considers the expected use of the asset; the expected useful life of other assets to which the useful life of the intangible asset may relate; legal, regulatory, or contractual provisions that may limit the useful life; the company's historical experience as evidence of its ability to support renewal or extension; the effects of obsolescence, demand, competition, and other economic factors; and the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

LG&E accounts for emission allowances as intangible assets. LG&E is allocated emission allowances by states based on its generation facilities' historical emissions experience, and have purchased emission allowances generally when it is expected that additional allowances will be needed. The carrying value of allocated emission allowances is initially recorded at zero value and purchased allowances are initially recorded based on their purchase price. When consumed or sold, emission allowances are removed from the Balance Sheet at their weighted-average carrying value. Since the economic benefits of emission allowances are not diminished until they are consumed, emission allowances are not amortized; rather, they are expensed when consumed or a gain or loss is recognized when sold. Such expense is included in "Fuel" on the Statements of Income. Gains and losses on the sale of emission allowances are included in "Other operation and maintenance" on the Statements of Income.

Asset Impairment (Excluding Investments)

LG&E reviews long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles, for impairment when events or circumstances indicate carrying amounts may not be recoverable.

A long-lived asset classified as held and used is impaired when the carrying amount of the asset exceeds the

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sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If impaired, the asset's carrying value is written down to its fair value.

A long-lived asset classified as held for sale is impaired when the carrying amount of the asset (disposal group) exceeds its fair value less cost to sell. If impaired, the asset's (disposal group's) carrying value is written down to its fair value less cost to sell.

LG&E reviews goodwill for impairment at the reporting unit level annually or more frequently when events or circumstances indicate that the carrying amount of a reporting unit may be greater than the unit's fair value. Additionally, goodwill must be tested for impairment in circumstances when a portion of goodwill has been allocated to a business to be disposed. LG&E is a single reporting unit.

LG&E may elect either to initially make a qualitative evaluation about the likelihood of an impairment of goodwill or to bypass the qualitative evaluation and test goodwill for impairment using a two-step quantitative test. If the qualitative evaluation (referred to as "step zero") is elected and the assessment results in a determination that it is not more likely than not that the fair value of a reporting unit is less than the carrying amount, the two-step quantitative impairment test is not necessary. However, the quantitative impairment test is required if management concludes it is more likely than not that the fair value of a reporting unit is less than the carrying amount based on the step zero assessment.

If the carrying amount of the reporting unit, including goodwill, exceeds its fair value, the implied fair value of goodwill must be calculated in the same manner as goodwill in a business combination. The fair value of a reporting unit is allocated to all assets and liabilities of that unit as if the reporting unit had been acquired in a business combination. The excess of the fair value of the reporting unit over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, goodwill is written down to its implied fair value.

LG&E elected to bypass step zero and quantitatively tested its goodwill for impairment in the fourth quarter of 2015 and no impairment was recognized.

Asset Retirement Obligations

LG&E records liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased through the recognition of accretion expense to reflect changes in the obligation due to the passage of time. The accretion and depreciation expenses recorded by LG&E are recorded as a regulatory asset, such that there is no earnings impact.

Estimated ARO costs and settlement dates, which affect the carrying value of the ARO and the related capitalized asset, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the ARO. Any change to the capitalized asset, positive or negative, is generally amortized over the remaining life of the associated long-lived asset. See Note 15 for additional information on AROs.

Compensation and Benefits

Defined Benefits

LG&E sponsors and participates in various defined benefit pension and other postretirement plans. The plans LG&E participates in are sponsored by LG&E and LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to LG&E based on its participation in those plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value.

LG&E and LKE use an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan's projected benefit obligation are amortized on a straight-line basis over one-half of the expected average remaining service of active plan participants. Actuarial gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or the market-related value of plan assets and less than 30% of the plan's projected benefit obligation are amortized on a straight-line basis over the expected average remaining service period of active plan participants.

See Note 4 for a discussion of the regulatory treatment of defined benefit costs and Note 8 for a discussion of defined benefits.

Taxes

Income Taxes

LG&E is included in PPL’s consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E’s provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and valuation allowances on deferred tax assets.

Significant management judgment is also required to determine the amount of benefit to be recognized in relation to an uncertain tax position. LG&E uses a two-step process to evaluate tax positions. The first step requires LG&E to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires LG&E to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is

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measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact LG&E's financial statements in future periods.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If LG&E determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if LG&E determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

LG&E defers investment tax credits when the credits are utilized and amortize the deferred amounts over the average lives of the related assets.

LG&E recognizes interest and penalties in "Income Taxes" on its Statements of Income.

LG&E's provision for deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in noncurrent "Regulatory assets" or "Regulatory liabilities."

LG&E's income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E filed a separate return. Tax benefits are not shared between companies. LG&E is only entitled to tax benefits that it generated. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes. LG&E's intercompany tax receivables were $4 million and $74 million at December 31, 2015 and 2014.

Taxes, Other Than Income

LG&E presents sales taxes in "Other current liabilities" on the Balance Sheets. These taxes are not reflected on the Statements of Income. See Note 3 for details on taxes included in "Taxes, other than income" on the Statements of Income.

Other

Leases

LG&E evaluates whether arrangements entered into contain leases for accounting purposes. See Note 7 for

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additional information.

Fuel, Materials and Supplies

Fuel, natural gas stored underground and materials and supplies are valued at the lower of cost or net realizable value using the average cost method. Fuel costs for electric generation are charged to expense as used. Natural gas supply costs are charged to expense as delivered to the distribution system. See Note 4 for further discussion of the fuel adjustment clause and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2015	2014
Fuel	$ 71	$ 66
Natural gas stored underground (a)	42	54
Materials and supplies	38	42
Total	$ 151	$ 162

(a) The majority of natural gas stored underground is held to serve retail customers.

Guarantees

Generally, the initial measurement of a guarantee liability is the fair value of the guarantee at its inception. However, there are certain guarantees excluded from the scope of accounting guidance and other guarantees that are not subject to the initial recognition and measurement provisions of accounting guidance that only require disclosure. See Note 10 for further discussion of recorded and unrecorded guarantees.

New Accounting Guidance Adopted

Fair Value Measurement for Investments in Certain Entities that Calculate Net Asset Value per Share

Effective December 31, 2015, LG&E retrospectively adopted accounting guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using net asset value per share and the requirement to make certain disclosures for all investments that are eligible to be measured using net asset value per share.

The adoption of this guidance resulted in LG&E no longer categorizing investments for which fair value is measured using net asset value per share in the fair value hierarchy, and did not have a significant impact on LG&E. See Note 8 for additional information.

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Presentation of Debt Issuance Costs

Effective December 31, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of debt issuance costs. The guidance requires certain debt issuance costs to be presented on the Balance Sheet as a direct deduction from the carrying amount of the associated debt liability.

The adoption of this guidance required LG&E to reclassify debt issuance costs not associated with a line of credit from noncurrent assets to Long-term debt, and did not have a significant impact. See Note 5 for additional information.

Balance Sheet Classification of Deferred Taxes

Effective October 1, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of deferred taxes which requires that deferred tax assets and deferred tax liabilities be classified as noncurrent on the Balance Sheet.

The adoption of this guidance required LG&E to reclassify deferred tax assets and deferred tax liabilities from current to noncurrent on the Balance Sheet, and did not have a significant impact. LG&E did not have any current deferred tax assets and liabilities on the Balance Sheet as of December 31, 2014.

2. Preferred Securities

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2015 or 2014.

3. Income and Other Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes and the tax effects of net operating loss and tax credit carryforwards. Net deferred tax assets have been recognized based on management's estimates of future taxable income.

LG&E's provision for deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC and the FERC. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets.

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Significant components of LG&E's deferred income tax assets and liabilities at December 31 were as follows:

	2015	2014
Deferred Tax Assets		
Federal loss carryforwards (a)	$ 76	$ -
Regulatory liabilities	38	51
Deferred investment tax credits	13	14
Income taxes due to customers	17	18
Derivative liability	18	32
Other	15	9
Total deferred tax assets	177	124
Deferred Tax Liabilities		
Plant - net	896	698
Regulatory assets	75	90
Accrued pension costs	28	28
Other	7	8
Total deferred tax liabilities	1,006	824
Net deferred tax liability	$ 829	$ 700

(a) Increase in Federal loss carryforwards primarily relates to the extension of bonus depreciation.

LG&E expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

At December 31, 2015, LG&E had $218 million of federal net operating loss carryforwards that expire in 2035, $1 million of federal credit carryforwards that expire from 2031 to 2035 and $2 million of state credit carryforwards that expire in 2022.

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Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were:

	2015	2014
Income Tax Expense (Benefit)		
Current - Federal	$ (15)	$ (25)
Current - State	3	10
Total Current Expense (Benefit)	(12)	(15)
Deferred - Federal	190	114
Deferred - State	13	6
Total Deferred Expense, excluding benefits of operating loss carryforwards	203	120
Investment tax credit, net - Federal	(1)	(2)
Tax benefit of operating loss carryforwards		
Deferred - Federal	(76)	-
Total Tax Benefit of Operating Loss Carryforwards	(76)	-
Total income tax expense	$ 114	$ 103
Total income tax expense - Federal	$ 98	$ 87
Total income tax expense - State	16	16
Total income tax expense	$ 114	$ 103

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	2015	2014
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 105	$ 95
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	11	10
Amortization of investment tax credit	(1)	(2)
Other	(1)	-
Total increase	9	8
Total income tax expense	$ 114	$ 103
Effective income tax rate	38.1%	37.9%

	2015	2014
Taxes, other than income		
Property and other	$ 28	$ 25
Total	$ 28	$ 25

Unrecognized Tax Benefits

LG&E's income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E filed a separate return. Based on this tax sharing agreement, LG&E indirectly files tax returns in two major tax jurisdictions. With few exceptions, at December 31, 2015, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows:

U.S. (federal)	2011 and prior
Kentucky (state)	2010 and prior

4. Utility Rate Regulation

Regulatory Assets and Liabilities

LG&E reflects the effects of regulatory actions in the financial statements for its cost-based rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the Balance Sheet date.

LG&E is subject to the jurisdiction of the KPSC and FERC.

LG&E's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and short-term debt) including adjustments for certain net investments and costs recovered separately through

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other means. As such, LG&E generally earns a return on regulatory assets.

As a result of purchase accounting requirements, certain fair value amounts related to contracts that had favorable or unfavorable terms relative to market were recorded on the Balance Sheet with an offsetting regulatory asset or liability. LG&E recovers in customer rates the cost of coal contracts, power purchases and emission allowances. As a result, management believes the regulatory assets and liabilities created to offset the fair value amounts at LKE's acquisition date meet the recognition criteria established by existing accounting guidance and eliminate any rate-making impact of the fair value adjustments. LG&E's customer rates will continue to reflect the original contracted prices for these contracts.

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The following table provides information about the regulatory assets and liabilities of cost-based rate-regulated utility operations at December 31.

	2015	2014
Current Regulatory Assets:		
Environmental cost recovery	$ 13	$ 4
Gas supply clause	1	15
Fuel adjustment clause	-	2
Gas line tracker	1	-
Other	1	-
Total current regulatory assets	$ 16	$ 21
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 215	$ 215
Storm costs	35	43
Unamortized loss on debt	17	18
Interest rate swaps	98	89
AROs	57	28
Other	2	4
Total noncurrent regulatory assets	$ 424	$ 397
Current Regulatory Liabilities:		
Demand side management	$ 4	$ 1
Gas supply clause	6	6
Fuel adjustment clause	2	-
Gas line tracker	-	3
Other	1	-
Total current regulatory liabilities	$ 13	$ 10
Noncurrent Regulatory Liabilities:		
Coal contracts (a)	$ 7	$ 25
Power purchase agreement - OVEC (a)	57	63
Net deferred tax assets	23	24
Interest rate swaps	41	42
Other	2	2
Total noncurrent regulatory liabilities	$ 130	$ 156

(a) These liabilities were recorded as offsets to certain intangible assets that were recorded at fair value upon the acquisition of LKE by PPL.

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Following is an overview of selected regulatory assets and liabilities detailed in the preceding tables. Specific developments with respect to certain of these regulatory assets and liabilities are discussed in "Regulatory Matters."

Defined Benefit Plans

Defined benefit plan regulatory assets represent the portion of unrecognized transition obligation, prior service cost and net actuarial gains and losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices and generally, are amortized over the average remaining service lives of plan participants. These regulatory assets are adjusted at least annually or whenever the funded status of defined benefit plans is re-measured. Of the regulatory asset balances recorded, costs of $19 million are expected to be amortized into net periodic defined benefit costs in 2016 in accordance with LG&E's pension accounting policy.

As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between pension cost calculated in accordance with LG&E's pension accounting policy and pension cost calculated using a 15 year amortization period for actuarial gains and losses is recorded as a regulatory asset. As of December 31, 2015, the balance was $6 million. Of the costs expected to be amortized into net periodic defined benefit costs in 2016, $6 million is expected to be recorded as a regulatory asset in 2016.

Storm Costs

LG&E has the ability to request from the KPSC, the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer such costs for regulatory accounting and reporting purposes. Once such authority is granted, LG&E can request recovery of those expenses in a base rate case and begin amortizing the costs when recovery starts. LG&E's regulatory assets for storm costs are being amortized through various dates ending in 2020.

Unamortized Loss on Debt

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed that have been deferred and will be amortized and recovered over either the original life of the extinguished debt or the life of the replacement debt (in the case of refinancing). Such costs are being amortized through 2035.

Environmental Cost Recovery

Kentucky law permits LG&E to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Clean Air Act and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from coal-fired electric generating facilities. The KPSC requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, LG&E was authorized to earn a 10% return on equity for all its existing ECR plans. The ECR regulatory asset or liability represents the amount that has been under- or

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over-recovered due to timing or adjustments to the mechanism and is typically recovered within 12 months.

Gas Supply Clause

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause includes a separate natural gas procurement incentive mechanism, which allows LG&E's rates to be adjusted annually to share variances between actual costs and market indices between the shareholders and the customers during each performance-based rate year (12 months ending October 31). The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are typically recovered within 18 months.

Fuel Adjustment Clauses

LG&E's retail electric rates contain a fuel adjustment clause, whereby variances in the cost of fuel to generate electricity, including transportation costs, from the costs embedded in base rates are adjusted in LG&E's rates. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel adjustment clause and, to the extent appropriate, reestablish the fuel charge included in base rates. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are typically recovered within 12 months.

Demand Side Management

LG&E's DSM program consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. LG&E's rates contain a DSM provision which includes a rate recovery mechanism that provides for concurrent recovery of DSM costs and incentives, and allows for the recovery of DSM revenues from lost sales associated with the DSM programs. Additionally, LG&E earns an approved return on equity for capital expenditures associated with the residential and commercial load management/demand conservation programs. The cost of DSM programs is assigned only to the class or classes of customers that benefit from the programs.

Interest Rate Swaps

Periodically, LG&E has entered into forward-starting interest rate swaps to hedge forecasted debt issuance with PPL that have terms identical to forward-starting swaps entered into by PPL with third parties. Net realized gains and losses on all of these swaps are probable of recovery through regulated rates; as such, any gains and losses on these derivatives are included in regulatory assets or liabilities and will be recognized in "Interest Expense" on the Statements of Income over the life of the underlying debt at the time the underlying hedged interest expense is recorded. In September 2015, first mortgage bonds totaling $550 million were issued and all outstanding forward-starting interest rate swaps were terminated. Net cash settlements of $44 million were paid on the swaps that were terminated. Net realized losses on these terminated swaps will be recovered through regulated rates. As such, the net settlements were recorded in regulatory assets and are being recognized in

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"Interest Expense" on the Statements of Income over the life of the new debt that matures in 2025 and 2045. There were no forward starting interest rate swaps outstanding at December 31, 2015. See Note 13 for additional information related to the forward-starting interest rate swaps.

Net cash settlements of $43 million were received on forward starting interest rate swaps that were terminated in 2013. Net realized gains on these terminated swaps will be returned through regulated rates. As such, the net settlements were recorded as regulatory liabilities and are being recognized in "Interest Expense" on the Statements of Income over the life of the associated debt that matures in 2043.

In addition to the terminated forward starting interest rate swaps, realized amounts associated with LG&E's other interest rate swaps, including a terminated swap contract from 2008, are recoverable through rates based on an order from the KPSC, LG&E's unrealized losses and gains are recorded as a regulatory asset or liability until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures through 2033. Amortization of the gain or loss related to the 2008 terminated swap contract is to be recovered through 2035.

AROs

The accretion and depreciation expenses related to LG&E's AROs are recorded as a regulatory asset, such that there is no earnings impact. When an asset with an ARO is retired, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

Gas Line Tracker

The GLT authorizes LG&E to recover its incremental operating expenses, depreciation, property taxes, and its cost of capital including a return on equity for capital associated with the five year gas service riser, leak mitigation and customer service line ownership programs. As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, LG&E is authorized to earn a 10% return on equity for the GLT mechanism. As part of this program, LG&E makes necessary repairs and assumes ownership of natural gas lines. LG&E annually files projected costs in October to become effective on the first billing cycle in January. After the completion of a plan year, LG&E submits a balancing adjustment filing to the KPSC to amend rates charged for the differences between the actual costs and actual GLT charges for the preceding year. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to these timing differences.

Coal Contracts

As a result of purchase accounting associated with PPL's acquisition of LKE, LG&E's coal contracts were recorded at fair value on the Balance Sheet with offsets to regulatory assets for those contracts with unfavorable terms relative to current market prices and offsets to regulatory liabilities for those contracts with favorable terms relative to current market prices. These regulatory assets and liabilities are being amortized over the same terms as the related contracts, which expire at various times through 2016.

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Power Purchase Agreement - OVEC

As a result of purchase accounting associated with PPL's acquisition of LKE, the fair value of the OVEC power purchase agreement was recorded on the Balance Sheet with offsets to regulatory liabilities. The regulatory liabilities are being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition.

Regulatory Liability Associated with Net Deferred Tax Assets

LG&E's regulatory liabilities associated with net deferred tax assets represent the future revenue impact from the reversal of deferred income taxes required primarily for unamortized investment tax credits. These regulatory liabilities are recognized when the offsetting deferred tax assets are recognized.

Regulatory Matters

Rate Case Proceedings

On June 30, 2015, the KPSC approved a rate case settlement agreement providing for increases in the annual revenue requirements associated with base gas rates of $7 million. The annual revenue requirement associated with base electricity rates was not changed. Although the settlement did not establish a specific return on equity with respect to the base rates, an authorized 10% return on equity will be utilized in the ECR and GLT mechanisms. The settlement also provides regulatory asset treatment for the difference between pension expense calculated in accordance with LG&E’s pension accounting policy and pension expense using a 15 year amortization period for actuarial gains and losses. The new rates and all elements of the settlement became effective July 1, 2015.

KPSC Landfill Proceedings

On May 22, 2015, LG&E and KU filed an application with the KPSC for a declaratory order that the existing CPCN and ECR approvals regarding the initial phases of construction and rate recovery of the landfill for management of CCRs at the Trimble County Station remain in effect. The current design of the proposed landfill provides for construction in substantially the same location as originally proposed with approximately the same storage capacity and expected useful life. On May 20, 2015, the owner of an underground limestone mine filed a complaint with the KPSC requesting it to revoke the CPCN for the Trimble County landfill and limit recovery of costs for the Ghent Station landfill on the grounds that, as a result of cost increases, the proposed landfill no longer constitutes the least cost alternative for CCR management. The KPSC has initiated its own investigation, consolidated the proceedings, and ordered an accelerated procedural schedule. The KPSC conducted a hearing on the matter in September 2015. On December 15, 2015, the KPSC issued an order affirming LG&E and KU's existing CPCN and ECR authority for Phase 1 of the Trimble County and Ghent landfills and related facilities, and that the landfills are the least cost options for disposing of the combustion wastes. Additionally, the order requires LG&E and KU to file a CPCN prior to constructing Phases 2 and 3 at the Ghent landfill and Phases 2 through 4 at the Trimble County landfill. The order also requires LG&E and KU to submit status update reports every three months on Phase 1 of Trimble County landfill. Phase 1 of construction at Trimble County will commence after the required state permits are obtained. Phase 1 of the

Ghent landfill was completed in December 2014.

CPCN and ECR Filing

On January 29, 2016, LG&E submitted an application to the KPSC for CPCNs and for ECR rate treatment regarding upcoming environmental construction projects relating to the EPA's regulations addressing the handling of coal combustion byproducts and MATS. The construction projects are expected to begin in 2016 and continue through 2023 and are estimated to cost LG&E approximately $316 million. The application requests an authorized 10% return on equity with respect to LG&E's ECR mechanism consistent with the 2014 Kentucky rate case approved in June 2015.

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5. Financing Activities

Credit Arrangements and Short-term Debt

LG&E maintains a credit facility to enhance liquidity, provide credit support and provide a backstop to commercial paper programs. The amounts borrowed below are recorded as "Short-term debt" on the Balance Sheets. The following credit facility was in place at:

	December 31, 2015				
	Expiration Date	Capacity	Borrowed	Letters of Credit and Commercial Paper Issued	Unused Capacity
Syndicated Credit Facility (a) (b)	July 2019	$ 500	-	$ 142	$ 358

	December 31, 2014	
	Borrowed	Letters of Credit and Commercial Paper Issued
Syndicated Credit Facility (a) (b)	-	$ 264

(a) LG&E pays customary fees under its facility and borrowings generally bear interest at LIBOR-based rates plus an applicable margin.
(b) The facilities contain a financial covenant requiring debt to total capitalization not to exceed 70% as calculated in accordance with the facility and other customary covenants. Additionally, as it relates to the syndicated credit facility and subject to certain conditions, LG&E may request up to a $100 million increase in its facility's capacity.

In January 2016, the expiration date for LG&E’s syndicated credit facility expiring in July 2019 was extended to December 2020.

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LG&E maintains a commercial paper program to provide an additional financing source to fund short-term liquidity needs, as necessary. Commercial paper issuances, included in "Short-term debt" on the Balance Sheets, are supported by LG&E's syndicated credit facility. The following commercial paper program was in place at:

December 31, 2015			
Weighted - Average Interest Rate	**Capacity**	**Commercial Paper Issuances**	**Unused Capacity**
0.71%	$ 350	$ 142	$ 208

December 31, 2014	
Weighted - Average Interest Rate	**Commercial Paper Issuances**
0.42%	$ 264

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Long-term Debt

	Weighted - Average Rate	Maturities (c)	December 31, 2015
First Mortgage Bonds (a) (b)	3.36%	2016 - 2045	$ 1,659
Total Long-term Debt Before Adjustments			1,659
Other			
Fair market value adjustments			(1)
Unamortized discount			(4)
Unamortized debt issuance costs			(12)
Total Long-term Debt			1,642
Less current portion of Long-term Debt			25
Total Long-term Debt, noncurrent			$ 1,617

			December 31, 2014
First Mortgage Bonds (a) (b)	2.85%	2015 - 2043	$ 1,359
Total Long-term Debt Before Adjustments			1,359
Other			
Fair market value adjustments			(1)
Unamortized discount			(5)
Unamortized debt issuance costs			(8)
Total Long-term Debt			1,345
Less current portion of Long-term Debt			250
Total Long-term Debt, noncurrent			$ 1,095

(a) LG&E's first mortgage bonds are secured by the lien of the LG&E 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $4.2 billion and $3.7 billion at December 31, 2015 and 2014.

(b) Includes LG&E's series of first mortgage bonds that were issued to the respective trustees of tax-exempt revenue bonds to secure its respective obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amounts, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. These first mortgage bonds were issued under the LG&E 2010 Mortgage Indenture and are secured as noted in (a)

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above. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of LG&E. The related revenue bond documents allow LG&E to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a LIBOR index rate.

At December 31, 2015, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a term rate mode totaled $391 million. At December 31, 2015, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a variable rate mode totaled $183 million.

Several series of the tax-exempt revenue bonds are insured by monoline bond insurers whose ratings were reduced due to exposures relating to insurance of sub-prime mortgages. Of the bonds outstanding, $135 million are in the form of insured auction rate securities, wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. During 2008, interest rates increased, and LG&E experienced failed auctions when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. As noted above, the instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes.

Certain of the variable rate tax-exempt revenue bonds totaling $23 million at December 31, 2015, are subject to tender for purchase by LG&E at the option of the holder and to mandatory tender for purchase by LG&E upon the occurrence of certain events.

(c) The table reflects principal maturities only, based on stated maturities or earlier put dates.

None of the outstanding debt securities noted above have sinking fund requirements. The aggregate maturities of long-term debt, based on stated maturities or earlier put dates, for the periods 2016 through 2020 and thereafter are as follows:

2016	$	25
2017		194
2018		98
2019		40
2020		-
Thereafter		1,302
Total	$	1,659

In September 2015, LG&E issued $300 million of 3.30% First Mortgage Bonds due 2025 and $250 million of 4.375% First Mortgage Bonds due 2045. LG&E received proceeds of $298 million and $248 million, net of discounts and underwriting fees, which were used to repay short-term debt, to repay 1.625% First Mortgage Bonds that matured in November 2015 and for general corporate purposes.

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Legal Separateness

The subsidiaries of PPL are separate legal entities. PPL's subsidiaries are not liable for the debts of PPL. Accordingly, creditors of PPL may not satisfy their debts from the assets of PPL's subsidiaries absent a specific contractual undertaking by a subsidiary to pay PPL's creditors or as required by applicable law or regulation. Similarly, PPL is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of PPL's subsidiaries may not satisfy their debts from the assets of PPL or its other subsidiaries absent a specific contractual undertaking by PPL or its other subsidiaries to pay the creditors or as required by applicable law or regulation.

Similarly, the subsidiaries of LKE are each separate legal entities. These subsidiaries are not liable for the debts of LKE. Accordingly, creditors of LKE may not satisfy their debts from the assets of LKE’s subsidiaries absent a specific contractual undertaking by a subsidiary to pay the creditors or as required by applicable law or regulation. Similarly, LKE is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of its subsidiaries may not satisfy their debts from the assets of LKE (or its other subsidiaries) absent a specific contractual undertaking by that parent or other subsidiary to pay such creditors or as required by applicable law or regulation.

Distributions and Related Restrictions

LKE primarily relies on dividends from its subsidiaries to fund its distributions to PPL. LG&E is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. LG&E believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. In February 2012, LG&E petitioned the FERC requesting authorization to pay dividends in the future based on retained earnings balances calculated without giving effect to the impact of purchase accounting adjustments for the acquisition of LKE by PPL. In May 2012, FERC approved the petitions with the further condition that LG&E may not pay dividends if such payment would cause its adjusted equity ratio to fall below 30% of total capitalization. Accordingly, at December 31, 2015, net assets of $1.1 billion were restricted for purposes of paying dividends to LKE, and net assets of $1.2 billion were available for payment of dividends to LKE. LG&E believes it will not be required to change its current dividend practices as a result of the foregoing requirement. Orders from the KPSC require LG&E to obtain prior consent or approval before lending amounts to PPL or LKE.

6. Acquisitions, Development and Divestitures

From time to time, LG&E evaluates opportunities for potential acquisitions, divestitures and development projects. Development projects are reexamined based on market conditions and other factors to determine whether to proceed with, modify or terminate the projects. Any resulting transactions may impact future financial results.

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Development

Capacity Needs

The Cane Run Unit 7 NGCC was put into commercial operation on June 19, 2015. As a result and to meet more stringent EPA regulations, LG&E retired one coal-fired generating unit at the Cane Run plant in March 2015 and retired the remaining two coal-fired generating units at the plant in June 2015. LG&E incurred costs of $11 million directly related to these retirements including inventory write-downs and separation benefits. However, there were no gains or losses on the retirement of these units.

In December 2014, a final order was issued by the KPSC approving the request to construct a 10 MW solar generation facility at E.W. Brown. LG&E and KU began construction activities in the fourth quarter of 2015 and project the plant to be placed into commercial operation by June 2016 at a cost of approximately $30 million.

7. Leases

LG&E has entered into various agreements for the lease of office space, vehicles, land, gas storage and other equipment.

Rent - Operating Leases

Rent expense for operating leases was $12 million and $7 million for the years ended December 31, 2015 and 2014.

Total future minimum rental payments for all operating leases are estimated to be:

2016	$	14
2017		14
2018		13
2019		7
2020		4
Thereafter		10
Total	$	62

8. Retirement and Postemployment Benefits

Defined Benefits

LG&E sponsors and participates in non-contributory defined benefit pension plans. These plans are applicable to the majority of LG&E employees. The plan LG&E participates in is sponsored by LKE. LG&E is allocated a portion of the funded status and costs of the plan sponsored by LKE based on its participation in the plan, which

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management believes is reasonable. LG&E’s and LKE’s defined benefit pension plans were closed to new salaried and bargaining unit employees hired after December 31, 2005. Employees hired after December 31, 2005 receive additional company contributions above the standard matching contributions to their savings plans.

The majority of employees are eligible for certain health care and life insurance benefits upon retirement through a contributory plan sponsored by LKE. Postretirement health benefits may be paid from 401(h) accounts established as part of the LKE plan within the PPL Services Corporation Master Trust, funded VEBA trusts and company funds.

The following table provides the components of net periodic defined benefit costs for LG&E's pension benefit plan for the years ended December 31.

	Pension Benefits	
	2015	2014
Net periodic defined benefit costs (credits):		
Service cost	$ 1	$ 1
Interest cost	14	15
Expected return on plan assets	(20)	(19)
Amortization of:		
Prior service cost (credit)	3	2
Actuarial (gain) loss (a)	11	6
Net periodic defined benefit costs (credits)	$ 9	$ 5
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:		
Net (gain) loss	$ 8	$ 14
Prior service cost (credit)	10	9
Amortization of:		
Prior service (cost) credit	(3)	(2)
Actuarial gain (loss)	(11)	(6)
Total recognized in regulatory assets	4	15
Total recognized in net periodic benefit costs and regulatory assets	$ 13	$ 20

(a) As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between actuarial (gain)/loss calculated in accordance with LG&E's pension accounting policy and actuarial (gain)/loss calculated using a 15 year amortization period was $3 million.

For the pension plan sponsored by LG&E, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2016 are $12 million ($5 million amortization of prior service cost and $7 million amortization of actuarial loss). For the pension plan LG&E participates in, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2016 are $7 million ($2 million

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amortization of prior service cost and $5 million amortization of actuarial loss). For the other postretirement plan LG&E participates in, the estimated amount to be amortized from regulatory assets into net periodic defined benefit costs in 2016 is $1 million (amortization of prior service cost).

As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between net periodic defined benefit costs calculated in accordance with LG&E's pension accounting policy and the net periodic defined benefit costs calculated using a 15 year amortization period for gains and losses is recorded as a regulatory asset. For the pension plan sponsored by LG&E, of the costs expected to be amortized into net periodic defined benefit costs in 2016, $4 million is expected to be recorded as a regulatory asset. For the pension plan LG&E participates in, of the costs expected to be amortized into net periodic defined benefit costs in 2016, $2 million is expected to be recorded as a regulatory asset.

The net periodic defined benefit costs charged to operating expense or regulatory assets, excluding amounts charged to construction work in progress and other non-expense accounts, for LG&E's pension benefits were $7 million and $3 million in 2015 and 2014. Allocations to LG&E for net periodic defined benefit costs charged to operating expense or regulatory assets, excluding amounts charged to construction work in progress and other non-expense accounts, for pension benefits were $5 million and $2 million in 2015 and 2014. Allocations to LG&E for net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction work in progress and other non-expense accounts, for other postretirement benefits were $4 million in both 2015 and 2014. These allocated amounts are based on LG&E's participation in those plans, which management believes is reasonable.

For the pension plan sponsored by LG&E, of the costs charged to operating expense or regulatory assets, excluding amounts charged to construction and other non-expense accounts, $2 million was recorded as regulatory assets during 2015 representing the difference between net periodic defined benefit costs under the pension accounting policy and using a 15 year amortization period for gains and losses. An additional $2 million was recorded as a regulatory asset for this difference for the pension plan in which LG&E participates during 2015.

LKE and LG&E adopted the new mortality tables issued by the Society of Actuaries in October 2014 (RP-2014 base tables) for their defined benefit pension plans and LKE's other postretirement benefit plan at December 31, 2014 and 2015. In addition, LKE and LG&E updated the basis for estimating projected mortality improvements and selected the IRS BB-2D two-dimensional improvement scales on a generational basis for all their defined benefit pension plans and LKE's other postretirement benefit plan. These new mortality assumptions reflect the recognition of both improved life expectancies and the expectation of continuing improvements in life expectancies. The use of the new base tables and improvement scale resulted in an increase to LG&E's defined benefit pension obligation, an increase to future expense and a decrease in funded status. The use of the new base tables and improvement scale also resulted in an increased allocation from LKE to LG&E for defined benefit pension and other postretirement benefit obligations and future expense and a decrease in allocated funded status.

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For the pension plan sponsored by LG&E, the following weighted-average assumptions were used in the valuation of the benefit obligations at December 31.

	Pension Benefits	
	2015	**2014**
Discount rate	4.49%	4.20%

For the pension plan sponsored by LG&E, the following weighted-average assumptions were used to determine the net periodic defined benefit costs for the years ended December 31.

	Pension Benefits	
	2015	**2014**
Discount rate	4.20%	5.13%
Expected return on plan assets (a)	7.00%	7.10%

(a) The expected long-term rates of return for pension and other postretirement benefits are based on management's projections using a best-estimate of expected returns, volatilities and correlations for each asset class. Each plan's specific current and expected asset allocations are also considered in developing a reasonable return assumption.

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The funded status of LG&E's plan at December 31 was as follows:

	Pension Benefits	
	2015	**2014**
Change in Benefit Obligation		
Benefit Obligation, beginning of period	$ 331	$ 291
Service cost	1	1
Interest cost	14	15
Plan amendments (a)	10	9
Actuarial (gain) loss	(15)	36
Gross benefits paid (b)	(15)	(21)
Benefit Obligation, end of period	$ 326	$ 331
Change in Plan Assets		
Plan assets at fair value, beginning of period	301	281
Actual return on plan assets	(2)	41
Employer contributions	13	-
Gross benefits paid (b)	(15)	(21)
Plan assets at fair value, end of period	297	301
Funded Status, end of period	$ (29)	$ (30)
Amounts recognized in the Balance Sheets consist of:		
Noncurrent liability	(29)	(30)
Net amount recognized, end of period	$ (29)	$ (30)
Amounts recognized in regulatory assets (pre-tax) consists of:		
Prior service cost (credit)	$ 29	$ 22
Net actuarial (gain) loss	95	98
Total	$ 124	$ 120
Total accumulated benefit obligation for defined benefit pension plan	$ 326	$ 330

(a) The plan was amended in December 2015 allowing terminated vested participants to elect to receive their accrued pension benefit as a one-time lump-sum payment effective January 1, 2016. The projected benefit obligation increased by $10 million as a result of the amendment.

The plan was amended in December 2014 to enhance the early retirement factors for all plan participants retiring on or after January 1, 2015. The projected benefit obligation increased by $9 million as a result of

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the amendment.

(b) LG&E's pension plan offered a limited-time program in 2014 during which terminated vested participants could elect to receive their accrued pension benefit as a one-time lump-sum payment. The gross benefits paid includes $8 million of lump-sum cash payments made to terminated vested participants in 2014 in connection with this offering.

LG&E's pension plan had projected and accumulated benefit obligations in excess of plan assets at December 31, 2015 and 2014.

In addition to the plan it sponsors, LG&E is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to LG&E for pension benefits resulted in a liability of $26 million and $27 million at December 31, 2015 and 2014. Allocations to LG&E for other postretirement benefits resulted in a liability of $77 million and $85 million at December 31, 2015 and 2014.

Plan Assets - Pension Plans

The pension plans sponsored by LKE and LG&E are invested in the PPL Services Corporation Master Trust (the Master Trust) that also includes 401(h) accounts that are restricted for certain other postretirement benefit obligations of PPL and LKE. The investment strategy for the Master Trust is to achieve a risk-adjusted return on a mix of assets that, in combination with LG&E's funding policy, will ensure that sufficient assets are available to provide long-term growth and liquidity for benefit payments, while also managing the duration of the assets to complement the duration of the liabilities. The Master Trust benefits from a wide diversification of asset types, investment fund strategies and external investment fund managers, and therefore has no significant concentration of risk.

The investment policy of the Master Trust outlines investment objectives and defines the responsibilities of the EBPB, external investment managers, investment advisor and trustee and custodian. The investment policy is reviewed annually by PPL's Board of Directors.

The EBPB created a risk management framework around the trust assets and pension liabilities. This framework considers the trust assets as being composed of three sub-portfolios: growth, immunizing and liquidity portfolios. The growth portfolio is comprised of investments that generate a return at a reasonable risk, including equity securities, certain debt securities and alternative investments. The immunizing portfolio consists of debt securities, generally with long durations, and derivative positions. The immunizing portfolio is designed to offset a portion of the change in the pension liabilities due to changes in interest rates. The liquidity portfolio consists primarily of cash and cash equivalents.

Target allocation ranges have been developed for each portfolio on a plan basis based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio on a plan basis, and seeks to obtain a target portfolio that emphasizes reduction of risk of loss from market volatility. In pursuing that goal, the EBPB establishes revised guidelines from time to time. EBPB

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investment guidelines as of the end of 2015 are presented below.

The asset allocation for the trust and the target allocation by portfolio at December 31 are as follows:

	Percentage of Trust Assets 2015 (a)	2015 Target Asset Allocation (a) Weighted Average
Growth Portfolio	**51%**	**50%**
Equity securities	25%	
Debt securities (b)	13%	
Alternative investments	13%	
Immunizing Portfolio	**47%**	**48%**
Debt securities (b)	42%	
Derivatives	5%	
Liquidity Portfolio	**2%**	**2%**
Total	100%	100%

	Percentage of Trust Assets 2014
Growth Portfolio	**51%**
Equity securities	26%
Debt securities (b)	13%
Alternative investments	12%
Immunizing Portfolio	**47%**
Debt securities (b)	44%
Derivatives	3%
Liquidity Portfolio	**2%**
Total	100%

(a) Allocations exclude consideration of a group annuity contract held by the LG&E and KU Retirement Plan.
(b) Includes commingled debt funds, which are treated as debt securities for asset allocation purposes.

LG&E's and LKE's pension plan assets are invested solely in the Master Trust, which is fully disclosed below. The fair value of LG&E's plan's assets of $297 million and $301 million at December 31, 2015 and 2014 represents an interest of approximately 9% and 6% in the Master Trust. The fair value of LKE's plans assets of $1.3 billion at December 31, 2015 and 2014 represents an interest of approximately 40% and 28% in the Master Trust.

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The fair value of net assets in the Master Trust by asset class and level within the fair value hierarchy was:

	December 31, 2015			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 225	$ 225	$ -	$ -
Equity securities				
U.S.:				
Large-cap	87	87	-	-
Large-cap fund measured at NAV (a)	197	-	-	-
Small-cap	85	85	-	-
International equity fund at NAV (a)	454	-	-	-
Commingled debt measured at NAV (a)	514	-	-	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	501	492	9	-
Residential/commercial backed securities	3	-	3	-
Corporate	747	-	737	10
International government	4	-	4	-
Other	7	-	7	-
Alternative investments				
Commodities measured at NAV (a)	70	-	-	-
Real estate measured at NAV (a)	118	-	-	-
Private equity measured at NAV (a)	81	-	-	-
Hedge funds measured at NAV (a)	171	-	-	-
Derivatives:				
Interest rate swaps and swaptions	80	-	80	-
Other	11	-	11	-
Insurance contracts	32	-	-	32
PPL Services Corporation Master Trust assets, at fair value	$ 3,387	$ 889	$ 851	$ 42
Receivables and payables, net (b)	(49)			
401(h) account restricted for other postretirement benefit obligations	(111)			
Total PPL Services Corporation Master Trust pension assets	$ 3,227			

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	December 31, 2014			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 246	$ 246	$ -	$ -
Equity securities				
U.S.:				
Large-cap	114	114	-	-
Large-cap fund measured at NAV (a)	318	-	-	-
Small-cap	145	145	-	-
International equity fund at NAV (a)	615	-	-	-
Commingled debt measured at NAV (a)	818	-	-	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	723	706	17	-
Residential/commercial backed securities	2	-	2	-
Corporate	1,109	-	1,088	21
International government	8	-	8	-
Other	9	-	9	-
Alternative investments				
Commodities measured at NAV (a)	90	-	-	-
Real estate measured at NAV (a)	148	-	-	-
Private equity measured at NAV (a)	104	-	-	-
Hedge funds measured at NAV (a)	223	-	-	-
Derivatives:				
Interest rate swaps and swaptions	92	-	92	-
Other	12	-	12	-
Insurance contracts	33	-	-	33
PPL Services Corporation Master Trust assets, at fair value	$ 4,809	$ 1,211	$ 1,228	$ 54
Receivables and payables, net (b)	(41)			
401(h) account restricted for other postretirement benefit obligations	(136)			
Total PPL Services Corporation Master Trust pension assets	$ 4,632			

(a) In accordance with accounting guidance certain investments that are measured at fair value using the net asset value per share (NAV), or its equivalent, practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.

(b) Receivables and payables represent amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

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A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2015 is as follows:

	Corporate debt	Insurance contracts	Total
Balance at beginning of period	$ 21	$ 33	$ 54
Actual return on plan assets			
Relating to assets still held			
at the reporting date	-	2	2
Relating to assets sold			
during the period	(1)	-	(1)
Purchases, sales and settlements	(10)	(3)	(13)
Balance at end of period	$ 10	$ 32	$ 42

A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2014 is as follows:

	Corporate debt	Insurance contracts	Total
Balance at beginning of period	$ 23	$ 37	$ 60
Actual return on plan assets			
Relating to assets still held			
at the reporting date	(1)	1	-
Relating to assets sold			
during the period	(1)	-	(1)
Purchases, sales and settlements	-	(5)	(5)
Balance at end of period	$ 21	$ 33	$ 54

The fair value measurements of cash and cash equivalents are based on the amounts on deposit.

The market approach is used to measure fair value of equity securities. The fair value measurements of equity securities (excluding commingled funds), which are generally classified as Level 1, are based on quoted prices in active markets. These securities represent actively and passively managed investments that are managed against various equity indices and exchange traded funds (ETFs).

Investments in commingled equity and debt funds are categorized as equity securities. Investments in commingled equity funds include funds that invest in U.S. and international equity securities. Investments in commingled debt funds include funds that invest in a diversified portfolio of emerging market debt obligations, as well as funds that invest in investment grade long-duration fixed-income securities.

The fair value measurements of debt securities are generally based on evaluations that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences. The fair value of debt securities is generally measured using a market approach, including the use of pricing models which incorporate observable inputs. Common inputs include benchmark yields, relevant trade data, broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as payment data, future predicted cash flows, collateral performance and new issue data. For the Master Trust, these securities represent investments in securities issued by U.S. Treasury and U.S. government sponsored agencies; investments securitized by residential mortgages, auto loans, credit cards and other pooled loans; investments in investment grade and non-investment grade bonds issued by U.S. companies across several industries; investments in debt securities issued by foreign governments and corporations.

Investments in commodities represent ownership interest of a commingled fund that is invested in a portfolio of exchange-traded futures and forward contracts in commodities to obtain broad exposure to all principal groups in the global commodity markets, including energies, agriculture and metals (both precious and industrial) using proprietary commodity trading strategies. Redemptions can be made the 15th calendar day and the last calendar day of the month with a specified notification period. The fund's fair value is based upon a value as calculated by the fund's administrator.

Investments in real estate represent an investment in a partnership whose purpose is to manage investments in core U.S. real estate properties diversified geographically and across major property types (e.g., office, industrial, retail, etc.). The manager is focused on properties with high occupancy rates with quality tenants. This results in a focus on high income and stable cash flows with appreciation being a secondary factor. Core real estate generally has a lower degree of leverage when compared with more speculative real estate investing strategies. The partnership has limitations on the amounts that may be redeemed based on available cash to fund redemptions. Additionally, the general partner may decline to accept redemptions when necessary to avoid adverse consequences for the partnership, including legal and tax implications, among others. The fair value of the investment is based upon a partnership unit value.

Investments in private equity represent interests in partnerships in multiple early-stage venture capital funds and private equity fund of funds that use a number of diverse investment strategies. Four of the partnerships have limited lives of ten years, while the fifth has a life of 15 years, after which liquidating distributions will be received. Prior to the end of each partnership's life, the investment cannot be redeemed with the partnership; however, the interest may be sold to other parties, subject to the general partner's approval. The Master Trust has unfunded commitments of $27 million that may be required during the lives of the partnerships. Fair value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

Investments in hedge funds represent investments in three hedge fund of funds. Hedge funds seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under most market conditions. Major investment strategies for the hedge fund of funds include long/short equity, market neutral, distressed debt, and relative value. Generally, shares may be redeemed within 60 to 95 days with prior written notice. The funds are subject to short term lockups and have limitations on the amount that may be withdrawn based on a percentage of the total net asset value of the fund, among other restrictions. All withdrawals are subject to the general partner's approval. The fair value for two of the funds has been estimated using the net asset value per share and the third fund's fair

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value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

The fair value measurements of derivative instruments utilize various inputs that include quoted prices for similar contracts or market-corroborated inputs. In certain instances, these instruments may be valued using models, including standard option valuation models and standard industry models. These securities primarily represent investments in interest rate swaps and swaptions (the option to enter into an interest rate swap) which are valued based on the swap details, such as swap curves, notional amount, index and term of index, reset frequency, volatility and payer/receiver credit ratings.

Insurance contracts, classified as Level 3, represent an investment in an immediate participation guaranteed group annuity contract. The fair value is based on contract value, which represents cost plus interest income less distributions for benefit payments and administrative expenses.

Plan Assets - Other Postretirement Benefit Plans

LKE's other postretirement benefit plan is invested primarily in a 401(h) account, as disclosed in the PPL Services Corporation Master Trust, with insignificant amounts invested in money market funds within VEBA trusts for liquidity.

Expected Cash Flows - Defined Benefit Plans

LG&E's defined benefit pension plan has the option to utilize available prior year credit balances to meet current and future contribution requirements. However, LG&E contributed $7 million to its pension plan in January 2016. LG&E also contributed $5 million to LKE’s pension plan on behalf of LG&E employees in January 2016.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the plan for LG&E retirees.

	LG&E Sponsored Pensions	Allocated from LKE Pension Plan
2016	$ 23	$ 15
2017	25	15
2018	24	16
2019	25	16
2020	25	16
2020-2025	111	84

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Savings Plans

Substantially all employees of LG&E are eligible to participate in deferred savings plans (401(k)s). Employer contributions to the plans were $5 million each in 2015 and 2014.

9. Jointly Owned Facilities

At December 31, 2015 and 2014, the Balance Sheets reflect the owned interests in the facilities listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
December 31, 2015				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 12	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	47	10	1
Trimble County Unit 1	75.00%	399	44	6
Trimble County Unit 2	14.25%	210	28	12
Trimble County Units 5-6	29.00%	29	6	-
Trimble County Units 7-10	37.00%	71	14	-
Cane Run Unit 7	22.00%	115	1	1
E.W. Brown Solar Unit	39.00%	-	-	4
December 31, 2014				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 10	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	47	7	-
Trimble County Unit 1	75.00%	309	51	59
Trimble County Unit 2	14.25%	205	23	15
Trimble County Units 5-6	29.00%	29	5	-
Trimble County Units 7-10	37.00%	70	11	-
Cane Run Unit 7	22.00%	-	-	113

LG&E provides its own funding for its share of each of the above facilities. LG&E receives a portion of the total output of the generating plants equal to its percentage ownership. The share of fuel and other operating costs associated with the plants is included in the corresponding operating expenses on the Statements of Income.

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10. Commitments and Contingencies

Energy Purchases Commitments

LG&E enters into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's gas supply operations. These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Coal	2022
Coal Transportation and Fleeting Services	2024
Natural Gas Storage and Transporation	2024
Natural Gas Transportation	2026

LG&E has a power purchase agreement with OVEC expiring in June 2040. See "Guarantees and Other Assurances" below for information on the OVEC power purchase contract. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses are projected as follows:

2016	$	18
2017		19
2018		19
2019		19
2020		20
Thereafter		435
	$	530

In addition, LG&E had total energy purchases under the OVEC power purchase agreement of $15 million and $17 million for the years ended December 31, 2015 and 2014.

Legal Matters

LG&E is involved in legal proceedings, claims and litigation in the ordinary course of business. LG&E cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

Cane Run Environmental Claims

In December 2013, six residents, on behalf of themselves and others similarly situated, filed a class action complaint against LG&E and PPL in the U.S. District Court for the Western District of Kentucky alleging

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violations of the Clean Air Act and RCRA. In addition, these plaintiffs assert common law claims of nuisance, trespass and negligence. These plaintiffs seek injunctive relief and civil penalties, plus costs and attorney fees, for the alleged statutory violations. Under the common law claims, these plaintiffs seek monetary compensation and punitive damages for property damage and diminished property values for a class consisting of residents within four miles of the plant. In their individual capacities, these plaintiffs seek compensation for alleged adverse health effects. In response to a motion to dismiss filed by LG&E and PPL, in July 2014, the court dismissed the plaintiffs' RCRA claims and all but one Clean Air Act claim, but declined to dismiss their common law tort claims. Upon motion of LG&E and PPL, the district court certified for appellate review the issue of whether the state common law claims are preempted by federal statute. In December 2014, the U.S. Court of Appeals for the Sixth Circuit issued an order granting appellate review regarding the above matter. Oral argument before the Sixth Circuit was held in August 2015. In November 2015, the Sixth Circuit issued an opinion affirming the District Court's ruling that plaintiffs' state law claims are not preempted by the Clean Air Act and remanding the matter to the District Court for further proceedings. Certain discovery matters are currently before the District Court. LG&E cannot predict the outcome of this matter. LG&E retired one coal-fired unit at the Cane Run plant in March 2015 and the remaining two coal-fired units at the plant in June 2015.

Mill Creek Environmental Claims

In May 2014, the Sierra Club filed a citizen suit against LG&E in the U.S. District Court for the Western District of Kentucky for alleged violations of the Clean Water Act. The Sierra Club alleges that various discharges at the Mill Creek plant constitute violations of the plant's water discharge permit. The Sierra Club seeks civil penalties, injunctive relief, costs and attorney's fees. In August 2015, the Court denied cross-motions for summary judgment filed by both parties and directed the parties to proceed with discovery. Discovery proceedings are underway and the parties have also conducted limited settlement discussions in the matter. LG&E cannot predict the outcome of this matter or the potential impact on the operations of the Mill Creek plant, including increased capital or operating costs, if any, but believes the plant is operating in compliance with the permits.

Trimble County Unit 2 Air Permit

The Sierra Club and other environmental groups petitioned the Kentucky Environmental and Public Protection Cabinet to overturn the air permit issued for the Trimble County Unit 2 baseload coal-fired generating unit, but the agency upheld the permit in an order issued in September 2007. In response to subsequent petitions by environmental groups, the EPA ordered certain non-material changes to the permit which, in January 2010, were incorporated into a final revised permit issued by the Kentucky Division for Air Quality. In March 2010, the environmental groups petitioned the EPA to object to the revised state permit. Until the EPA issues a final ruling on the pending petition and all available appeals are exhausted, LG&E cannot predict the outcome of this matter or the potential impact on the operations of the Trimble County plant, including increased capital or operating costs, if any.

Trimble County Water Discharge Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the

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Kentucky Energy and Environment Cabinet (KEEC) challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County plant. In November 2010, the KEEC issued a final order upholding the permit which was subsequently appealed by the environmental groups. In September 2013, the Franklin Circuit Court reversed the KEEC order upholding the permit and remanded the permit to the agency for further proceedings. LG&E and the KEEC appealed the order to the Kentucky Court of Appeals. In July 2015, the Court of Appeals upheld the lower court ruling. LG&E and the KEEC have moved for discretionary review by the Kentucky Supreme Court. On February 10, 2016, the Kentucky Supreme Court issued an order granting discretionary review. LG&E is unable to predict the outcome of this matter or the potential impact on the operations of the Trimble County plant, including increased capital or operating costs, if any.

Regulatory Issues

See Note 4 for information on regulatory matters related to utility rate regulation.

Electricity - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations.

LG&E monitors its compliance with the Reliability Standards and continues to self-report or self-log potential violations of certain applicable reliability requirements and submit accompanying mitigation plans, as required. The resolution of a small number of potential violations is pending. Any Regional Reliability Entity (including RFC or SERC) determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC.

In the course of implementing its programs to ensure compliance with the Reliability Standards, certain other instances of potential non-compliance may be identified from time to time. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

Environmental Matters

Due to the environmental issues discussed below or other environmental matters, it may be necessary for LG&E to modify, curtail, replace or cease operation of certain facilities or performance of certain operations to comply with statutes, regulations and other requirements of regulatory bodies or courts. In addition, legal challenges to new environmental permits or rules add to the uncertainty of estimating the future cost of these permits and rules.

LG&E is entitled to recover, through the ECR mechanism, certain costs of complying with the Clean Air Act, as

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amended, and those federal, state or local environmental requirements applicable to coal combustion wastes and by-products from facilities that generate electricity from coal in accordance with approved compliance plans. Costs not covered by the ECR mechanism are subject to rate recovery before the KPSC or the FERC. LG&E can provide no assurances as to the ultimate outcome of future environmental or rate proceedings before regulatory authorities.

Air

The Clean Air Act, which regulates air pollutants from mobile and stationary sources, has a significant impact on the operation of fossil fuel plants. The Clean Air Act requires the EPA periodically to review and establish concentration levels in the ambient air for six criteria pollutants to protect public health and welfare. These concentration levels are known as NAAQS. The six criteria pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter and sulfur dioxide.

Federal environmental regulations of these criteria pollutants require states to adopt implementation plans, known as state implementation plans, for certain pollutants, which detail how the state will attain the standards that are mandated by the relevant law or regulation. Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas), and must develop a state implementation plan both to bring non-attainment areas into compliance with the NAAQS and to maintain good air quality in attainment areas. In addition, for attainment of ozone and fine particulates standards, states in the eastern portion of the country, including Kentucky, are subject to a regional program developed by the EPA known as the Cross-State Air Pollution Rule. The NAAQS, future revisions to the NAAQS and state implementation plans implementing them, or future revisions to regional programs, may require installation of additional pollution controls, the costs of which LG&E believes are subject to cost recovery.

Although LG&E does not currently anticipate significant costs to comply with these programs, changes in market or operating conditions could result in different costs than anticipated.

National Ambient Air Quality Standards (NAAQS)

Under the Clean Air Act, the EPA is required to reassess the NAAQS for certain air pollutants on a five-year schedule. In 2008, the EPA revised the NAAQS for ozone and proposed to further strengthen the standard in November 2014. The EPA released a new ozone standard on October 1, 2015. The states and EPA will determine attainment with the new ozone standard through review of relevant ambient air monitoring data, with attainment or nonattainment designations scheduled no later than October 2017. States are also obligated to address interstate transport issues associated with new ozone standards through the establishment of "good neighbor" state implementation plans for those states that are found to contribute significantly to another states' non-attainment. States that are not in the ozone transport region, including Kentucky, are working together to evaluate further nitrogen oxide reductions from fossil-fueled plants with SCRs. The nature and timing of any additional reductions resulting from these evaluations cannot be predicted at this time.

In 2010, the EPA finalized revised NAAQS for sulfur dioxide and required states to identify areas that meet those standards and areas that are in "non-attainment". In July 2013, the EPA finalized non-attainment designations for parts of the country, including part of Jefferson County in Kentucky. Attainment must be

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achieved by 2018. LG&E anticipates that certain previously required compliance measures, such as upgraded or new sulfur dioxide scrubbers at certain plants and the retirement of coal-fired generating units at LG&E's Cane Run plant, will help to achieve compliance with the new sulfur dioxide and ozone standards. If additional reductions are required, the costs could be significant.

Mercury and Air Toxics Standards (MATS)

In February 2012, the EPA finalized the MATS rule requiring reductions of mercury and other hazardous air pollutants from fossil-fuel fired power plants, with an effective date of April 16, 2012. The MATS rule was challenged by industry groups and states and was upheld by the U.S. Court of Appeals for the D. C. Circuit Court (D.C. Circuit Court) in April 2014. A group of states subsequently petitioned the U.S. Supreme Court (Supreme Court) to review this decision and in June 2015, the Supreme Court held that the EPA failed to properly consider costs when deciding to regulate hazardous air emissions from power plants under MATS. The Court remanded the matter to the D.C. Circuit Court, which in December 2015 remanded the rule to EPA without vacating it. EPA has proposed a supplemental finding regarding costs of the rule and has announced that it intends to make a final determination in 2016. The EPA's MATS rule remains in effect during the pendency of the ongoing proceedings.

LG&E has installed significant controls in connection with the MATS rule and in conjunction with compliance with other environmental requirements, including fabric-filter baghouses, upgraded scrubbers or chemical additive systems for which appropriate KPSC authorization and/or ECR treatment has been received. LG&E is currently seeking KPSC approval for a compliance plan providing for installation of additional MATS-related controls, the cost of which is currently estimated at $5 million. LG&E cannot predict the outcome of the MATS rule or its potential impact, if any, on plant operations, rate treatment or future capital or operating needs. See Note 4 for additional information.

New Source Review (NSR)

The NSR litigation brought by EPA, states and environmental groups against coal-fired generating plants in past years continues to proceed through the courts. Although none of this litigation directly involves LG&E, it can influence the permitting of large capital projects at LG&E's power plants, the costs of which cannot presently be determined but could be significant.

Climate Change

There is continuing momentum to address climate change. Most recently, in December 2015, 195 nations, including the U.S., signed the Paris Agreement on Climate which establishes a comprehensive framework for the reduction of GHG emissions from both developed and developing nations. Although the agreement does not establish binding reduction requirements, it requires each nation to prepare, communicate, and maintain GHG reduction commitments. Based on EPA's Clean Power Plan described below, the U.S. has committed to an initial reduction target of 26% to 28% below 2005 levels by 2025.

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The EPA's Rules under Section 111 of the Clean Air Act

As further described below, the EPA finalized rules imposing greenhouse gas emission standards for both new and existing power plants. The EPA has also issued a proposed federal implementation plan that would apply to any states that fail to submit an acceptable state implementation plan under these rules. The EPA's authority to promulgate these regulations under Section 111 of the Clean Air Act has been challenged in the D.C. Circuit Court by several states and industry groups. On February 9, 2016, the Supreme Court stayed the rule for existing plants (the Clean Power Plan) pending the D.C. Circuit Court's review and subsequent review by the Supreme Court if a writ of certiorari is filed and granted.

The EPA's rule for new power plants imposes separate emission standards for coal and natural gas units based on the application of different technologies. The coal standard is based on the application of partial carbon capture and sequestration technology, but because this technology is not presently commercially available, the rule effectively precludes the construction of new coal-fired plants. The standard for NGCC power plants is the same as the EPA proposed in 2012 and is not continuously achievable. The preclusion of new coal-fired plants and the compliance difficulties posed for new natural gas-fired plants could have a significant industry-wide impact.

The EPA's Clean Power Plan

The EPA's rule for existing power plants, referred to as the Clean Power Plan, was published in the Federal Register in October 2015. The Clean Power Plan contains state-specific rate-based and mass-based reduction goals and guidelines for the development, submission and implementation of state implementation plans to achieve the state goals. State-specific goals were calculated from 2012 data by applying EPA's broad interpretation and definition of the BSER, resulting in the most stringent targets to be met in 2030, with interim targets to be met beginning in 2022. The EPA believes it has offered some flexibility to the states as to how their compliance plans can be crafted, including the option to use a rate-based approach (limit emissions per megawatt hour) or a mass-based approach (limit total tons of emissions per year), and the option to demonstrate compliance through emissions trading and multi-state collaborations. Under the rate-based approach, Kentucky would need to make a 41% reduction from its 2012 emissions rate and under a mass-based approach it would need to make a 36% reduction. These reductions are significantly greater than initially proposed and present significant challenges to the state. If the Clean Power Plan is ultimately upheld and Kentucky fails to develop an approvable implementation plan by the applicable deadline, the EPA would impose a federal implementation plan that could be more stringent than what the state plan might provide. Depending on the provisions of the Kentucky implementation plan, LG&E may need to modify its current portfolio of generating assets during the next decade and/or participate in an allowance trading program.

LG&E is participating in the ongoing regulatory processes at the state and federal level in an effort to provide input into the state or federal implementation plan that will govern reductions in Kentucky. Various states, industry groups, and individual companies including LKE have filed petitions for reconsideration with EPA and petitions for review with the D.C. Circuit Court challenging the Clean Power Plan. LG&E cannot predict the outcome of this matter or the potential impact, if any, on plant operations, or future capital or operating needs. LG&E believes that the costs, which could be significant, would be subject to cost recovery.

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In April 2014, the Kentucky General Assembly passed legislation which limits the measures that the Kentucky Energy and Environment Cabinet may consider in setting performance standards to comply with the EPA's regulations governing GHG emissions from existing sources. The legislation provides that such state GHG performance standards shall be based on emission reductions, efficiency measures, and other improvements available at each power plant, rather than renewable energy, end-use energy efficiency, fuel switching and re-dispatch. These statutory restrictions may make it more difficult for Kentucky to achieve the GHG reduction levels that the EPA has established for Kentucky.

<u>Water/Waste</u>

Coal Combustion Residuals (CCRs)

On April 17, 2015, the EPA published its final rule regulating CCRs. CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. The rule became effective on October 19, 2015. It imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. Under the rule, the EPA will regulate CCRs as non-hazardous under Subtitle D of RCRA and allow beneficial use of CCRs, with some restrictions. The rule's requirements for covered CCR impoundments and landfills include implementation of groundwater monitoring and commencement or completion of closure activities generally between three and ten years from certain triggering events. This self-implementing rule requires posting of compliance documentation on a publicly accessible website and is enforceable solely through citizen suits. LG&E is also subject to state rules applicable to CCR management which may potentially be modified to reflect some or all requirements of the federal rule.

LG&E is currently pursuing KPSC approval for a compliance plan providing for closure of impoundments at the Mill Creek and Trimble County stations, and construction of process water management facilities at those plants. LG&E currently estimate the cost of these CCR compliance measures at $311 million. See Note 4 for additional information.

In connection with the final CCR rule, LG&E recorded increases to existing AROs during 2015. See Note 15 for additional information. Further increases to AROs or changes to current capital plans or to operating costs may be required as estimates are refined based on closure developments, groundwater monitoring results, and regulatory or legal proceedings. Costs relating to this rule are subject to rate recovery.

Clean Water Act

Regulations under the federal Clean Water Act dictate permitting and mitigation requirements for many of LG&E's construction projects. Many of those requirements relate to power plant operations, including requirements related to the treatment of pollutants in effluents prior to discharge, the temperature of effluent discharges and the location, design and construction of cooling water intake structures at generating facilities, standards intended to protect aquatic organisms by reducing capture in the screens attached to cooling water intake structures (impingement) at generating facilities and the water volume brought into the facilities (entrainment). The requirements could impose significant costs which are subject to rate recovery.

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Effluent Limitations Guidelines (ELGs)

On September 30, 2015, the EPA released its final effluent limitations guidelines for wastewater discharge permits for new and existing steam electric generating facilities. The rule provides strict technology-based discharge limitations for control of pollutants in scrubber wastewater, fly ash and bottom ash transport water, mercury control wastewater, gasification wastewater, and combustion residual leachate. The new guidelines require deployment of additional control technologies providing physical, chemical, and biological treatment of wastewaters. The guidelines also mandate operational changes including "no discharge" requirements for fly ash and bottom ash transport waters and mercury control wastewaters. The implementation date for individual generating stations will be determined by the states on a case-by-case basis according to criteria provided by the EPA, but the requirements of the rule must be fully implemented no later than 2023. It has not been decided how Kentucky intends to integrate the ELGs into its routine permit renewal process. LG&E continues to assess the requirements of this complex rule to determine available compliance strategies. LG&E is unable to fully estimate compliance costs or timing at this time although certain preliminary estimates are included in current capital forecasts, for applicable periods. Costs to comply with ELGs or other discharge limits, which are expected to be significant, are subject to rate recovery.

Clean Water Act Section 316(b)

The EPA's final 316(b) rule for existing facilities became effective in October 2014, and regulates cooling water intake structures and their impact on aquatic organisms. States are allowed broad discretion to make site-specific determinations under the rule. The rule requires existing facilities to choose between several options to reduce the impact to aquatic organisms that become trapped against water intake screens (impingement) and to determine the intake structure's impact on aquatic organisms pulled through a plant's cooling water system (entrainment). Plants equipped with closed-cycle cooling, an acceptable option, would likely not incur substantial costs. Once-through systems would likely require additional technology to comply with the rule. Mill Creek Unit 1 is the only unit expected to be impacted. LG&E is evaluating compliance strategies but do not presently expect the compliance costs, which are subject to rate recovery, to be significant.

Waters of the United States (WOTUS)

The U.S. Court of Appeals for the Sixth Circuit has issued a stay of EPA's rule on the definition of WOTUS pending the court's review of the rule. The effect of the stay is that the WOTUS rule is not currently in effect anywhere in the United States. The ultimate outcome of the court's review of the rule remains uncertain. LG&E does not expect the rule to have a significant impact on its operations.

Other Issues

The EPA is reassessing its polychlorinated biphenyls (PCB) regulations under the Toxic Substance Control Act, which currently allow certain PCB articles to remain in use. In April 2010, the EPA issued an Advanced Notice of Proposed Rulemaking for changes to these regulations. This rulemaking could lead to a phase-out of all or some PCB-containing equipment. The EPA has postponed the release of the revised regulations to March 2016. LG&E cannot predict at this time the outcome of these proposed EPA regulations and what impact, if any, they would have on its facilities, but the costs could be significant.

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Superfund and Other Remediation

LG&E is investigating, responding to agency inquiries, remediating, or have completed the remediation of, several sites that were not addressed under a regulatory program such as Superfund, but for which LG&E may be liable for remediation. These include a number of former coal gas manufacturing plants previously owned or operated or currently owned by predecessors or affiliates of LG&E. To date, the costs of these sites have not been significant.

There are additional sites, formerly owned or operated by LG&E predecessors or affiliates. LG&E lacks information on the conditions of such additional sites and are therefore unable to estimate any potential liability it may have or a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require LG&E to take more extensive assessment and remedial actions at former coal gas manufacturing plants. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, LG&E undertakes remedial action in response to notices of violations, spills or other releases at various on-site and off-site locations, negotiate with the EPA and state and local agencies regarding actions necessary for compliance with applicable requirements, negotiate with property owners and other third parties alleging impacts from LG&E's operations and undertake similar actions necessary to resolve environmental matters that arise in the course of normal operations. Based on analyses to date, resolution of these environmental matters is not expected to have a significant adverse impact on LG&E's operations.

Future cleanup or remediation work at sites currently under review, or at sites not currently identified, may result in significant additional costs. Insurance policies maintained by LG&E may be applicable to certain of the costs or other obligations related to these matters but the amount of insurance coverage or reimbursement cannot be estimated or assured.

Other

Guarantees and Other Assurances

In the normal course of business, LG&E enters into agreements that provide financial performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees, stand-by letters of credit issued by financial institutions and surety bonds issued by insurance companies. These agreements are entered into primarily to support or enhance the creditworthiness attributed to a subsidiary on a stand-alone basis or to facilitate the commercial activities in which these subsidiaries engage.

Pursuant to the OVEC power purchase contract, LG&E is obligated to pay for its share of OVEC's excess debt service, post-retirement and decommissioning costs, as well as any shortfall from amounts currently included within a demand charge designed and currently expected to cover these costs over the term of the contract. LG&E's proportionate share of OVEC's outstanding debt was $86 million at December 31, 2015. The maximum exposure and the expiration date of these potential obligations are not presently determinable. See "Energy Purchases, Energy Sales and Other Commitments" above for additional information on the OVEC power purchase contract.

LG&E provides other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries, including LG&E, maintains insurance that covers liability assumed under contract for bodily injury and property damage. The coverage provides maximum aggregate coverage of $225 million. This insurance may be applicable to obligations under certain of these contractual arrangements.

11. Related Party Transactions

Wholesale Sales and Purchases

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. When LG&E has excess generation capacity after serving its own retail customers and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail customers and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost plus any split savings. Savings realized from such intercompany transactions are shared equally between both companies. The volume of energy each company has to sell to the other is dependent on its retail customers' needs and its available generation.

Support Costs

LKS provides LG&E with administrative, management and support services. The costs of these services are charged to LG&E as direct support costs. General costs that cannot be directly attributed to a specific LKE subsidiary are allocated and charged to LG&E and other subsidiaries as indirect support costs. LKS bases its indirect allocations on the subsidiaries' number of employees, total assets, revenues, number of customers and/or other statistical information.

LKS charged LG&E $155 million and $140 million for the years ended December 31, 2015 and 2014, including amounts applied to accounts that are further distributed between capital and expense on LG&E’s books, based on methods that are believed to be reasonable.

In addition to the charges for services noted above, LKS makes payments on behalf of LG&E for fuel purchases and other costs for products or services provided by third parties. LG&E and KU also provide services to each other and to LKS. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between LKE and LG&E are reimbursed through LKS.

Intercompany Derivatives

Periodically, LG&E enters into forward-starting interest rate swaps with PPL. These hedging instruments have terms identical to forward-starting swaps entered into by PPL with third parties. See Note 13 for additional information on intercompany derivatives.

Other

See Note 1 for discussions regarding the intercompany tax sharing agreement. See Note 8 for discussions regarding intercompany allocations associated with defined benefits.

12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). A market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models), and/or a cost approach (generally, replacement cost) are used to measure the fair value of an asset or liability, as appropriate. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk. The fair value of a group of financial assets and liabilities is measured on a net basis. Transfers between levels are recognized at end-of-reporting-period values. During 2015 and 2014, there were no transfers between Level 1 and Level 2. See Note 1 for information on the levels in the fair value hierarchy.

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Recurring Fair Value Measurements

The assets and liabilities measured at fair value were:

	December 31, 2015			
	Total	**Level 1**	**Level 2**	**Level 3**
Assets				
Cash and cash equivalents	$ 19	$ 19	$ -	$ -
Cash collateral posted to counterparties (a)	9	9	-	-
Total assets	$ 28	$ 28	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 47	$ -	$ 47	$ -
Total price risk management liabilities	$ 47	$ -	$ 47	$ -

	December 31, 2014			
	Total	**Level 1**	**Level 2**	**Level 3**
Assets				
Cash and cash equivalents	$ 10	$ 10	$ -	$ -
Cash collateral posted to counterparties (a)	21	21	-	-
Total assets	$ 31	$ 31	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 81	$ -	$ 81	$ -
Total price risk management liabilities	$ 81	$ -	$ 81	$ -

(a) Included in "Other noncurrent assets" on the Balance Sheets. Represents cash collateral posted to offset the exposure with counterparties related to certain interest rate swaps under master netting arrangements that are not offset.

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage interest rate risk, LG&E uses interest rate contracts such as forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. An income approach is used to measure the fair value of these contracts, utilizing readily observable inputs, such as forward interest rates (e.g., LIBOR and government security rates), as well as inputs that may not be observable, such as credit valuation adjustments. In certain cases, market information cannot practicably be obtained to value credit risk and therefore internal models are relied upon.

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These models use projected probabilities of default and estimated recovery rates based on historical observances. When the credit valuation adjustment is significant to the overall valuation, the contracts are classified as Level 3.

Financial Instruments Not Recorded at Fair Value

The carrying amounts of long-term debt on the Balance Sheets and their estimated fair values are set forth below. The fair values were estimated using an income approach by discounting future cash flows at estimated current cost of funding rates, which incorporate LG&E's credit risk. Long-term debt is classified as Level 2. The effect of third-party credit enhancements is not included in the fair value measurement.

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,642	$ 1,704	$ 1,345	$ 1,455

The carrying value of short-term debt, when outstanding, approximates fair value due to the variable interest rates associated with the short-term debt and is classified as Level 2.

13. Derivative Instruments and Hedging Activities

Risk Management Objectives

PPL has a risk management policy approved by the Board of Directors to manage market risk associated with commodities and interest rates on debt issuances (including price, liquidity and volumetric risk), and credit risk (including non-performance risk and payment default risk). The Risk Management Committee, comprised of senior management and chaired by the Chief Risk Officer, oversees the risk management function. Key risk control activities designed to ensure compliance with the risk policy and detailed programs include, but are not limited to, credit review and approval, validation of transactions, verification of risk and transaction limits and the coordination and reporting of the Enterprise Risk Management (ERM) program.

Market Risk

Market risk includes the potential loss that may be incurred as a result of price changes associated with a particular financial or commodity instrument as well as market liquidity and volumetric risks. Forward contracts and swaps are utilized as part of risk management strategies to minimize unanticipated fluctuations in earnings caused by changes in commodity prices and interest rates. Many of the contracts meet the definition of a derivative. All derivatives are recognized on the Balance Sheets at their fair value, unless NPNS is elected.

The following summarizes the market risks that affect LG&E. These risks are significantly mitigated due to recovery mechanisms in place.

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Interest rate risk

- LG&E is exposed to interest rate risk associated with forecasted fixed-rate and existing floating-rate debt issuances. LG&E utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on floating-rate debt, and utilizes forward starting interest rate swaps to hedge changes in benchmark interest rates, when appropriate, in connection with future debt issuances.

- LG&E is exposed to interest rate risk associated with debt securities and derivatives held by defined benefit plans.

Commodity price risk

- LG&E's rates include certain mechanisms for fuel, natural gas supply and fuel-related expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses.

Equity securities price risk

- LG&E is exposed to equity securities price risk associated with defined benefit plans. This risk is significantly mitigated due to recovery mechanisms in place.

Credit Risk

Credit risk is the potential loss that may be incurred due to a counterparty's non-performance.

In the event a supplier of LG&E defaults on its obligation, LG&E would be required to seek replacement power or replacement fuel in the market. In general, subject to regulatory review or other processes, appropriate incremental costs incurred by LG&E would be recoverable from customers through applicable rate mechanisms, thus mitigating its financial risk.

LG&E has credit policies in place to manage credit risk, including the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements or provisions. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. LG&E may request additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade, their tangible net worth falls below specified percentages or their exposures exceed an established credit limit.

Master Netting Arrangements

Net derivative positions on the Balance Sheets are not offset against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

LG&E had no obligation to return cash collateral under master netting arrangements at December 31, 2015 and

2014.

LG&E posted $9 million and $21 million of cash collateral under master netting arrangements at December 31, 2015 and 2014.

See "Offsetting Derivative Instruments" below for a summary of derivative positions presented in the Balance Sheets where a right of setoff exists under these arrangements.

Interest Rate Risk

LG&E issues debt to finance its operations, which exposes it to interest rate risk. Various financial derivative instruments are utilized to adjust the mix of fixed and floating interest rates in its debt portfolio, adjust the duration of the debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under LG&E's risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of the debt portfolio due to changes in benchmark interest rates.

Cash Flow Hedges

Periodically, LG&E enters into forward-starting interest rate swaps with PPL that have terms identical to forward-starting swaps entered into by PPL with third parties. It is probable that realized gains and losses on all of these swaps will be recoverable through regulated rates; as such, any gains and losses on these derivatives are included in regulatory assets or liabilities and will be recognized in "Interest Expense" on the Statements of Income over the life of the underlying debt at the time the underlying hedged interest expense is recorded. In September 2015, LG&E issued first mortgage bonds totaling $550 million and all outstanding forward-starting interest rate swaps were terminated. Net cash settlements of $44 million were paid on the swaps that were terminated. The settlements are included in "Regulatory assets" (noncurrent) on the Balance Sheet and "Cash Flows from Operating Activities" on the Statements of Cash Flows.

Economic Activity

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statement of Income at the time the underlying hedged interest expense is recorded. At December 31, 2015, LG&E held contracts with a notional amount of $179 million that range in maturity through 2033.

Accounting and Reporting

All derivative instruments are recorded at fair value on the Balance Sheets as an asset or liability unless NPNS is elected. Changes in the fair value of derivatives not designated as NPNS are recognized currently in earnings unless specific hedge accounting criteria are met and designated as such, except for the changes in fair values of

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LG&E's interest rate swaps that are recognized as regulatory assets or regulatory liabilities. See Note 4 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2015 and 2014.

See Note 1 for additional information on accounting policies related to derivative instruments.

The following table presents the fair value and the location on the Balance Sheets of derivative instruments designated as cash flow hedges.

	December 31, 2015		December 31, 2014	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Current:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	$ -	$ -	$ -	$ 33

(a) Represents the location on the Balance Sheets.

The following table presents the pre-tax effect of derivative instruments designated as cash flow hedges that are recognized in regulatory assets and liabilities.

Derivative Instruments	**Location of Gain (Loss)**	**2015**	**2014**
Interest rate swaps	Regulatory asset - noncurrent	$ (11)	$ (33)
	Regulatory liabilities - noncurrent	-	-

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The following table presents the fair value and the location on the Balance Sheets of derivatives not designated as hedging instruments.

	December 31, 2015 Assets	December 31, 2015 Liabilities	December 31, 2014 Assets	December 31, 2014 Liabilities
Current:				
Other Current Assets/Liabilities (a):				
Interest rate swaps	$ -	$ 5	$ -	$ 5
Total current	-	5	-	5
Noncurrent:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	-	42	-	43
Total noncurrent	-	42	-	43
Total derivatives	$ -	$ 47	$ -	$ 48

(a) Represents the location on the Balance Sheets.

The following tables present the pre-tax effect of derivatives not designated as cash flow hedges that are recognized in income or regulatory assets.

Derivative Instruments	Location of Gain (Loss)	2015	2014
Interest rate swaps	Interest Expense	$ (8)	$ (8)

Derivative Instruments	Location of Gain (Loss)	2015	2014
Interest rate swaps	Regulatory assets - noncurrent	$ 1	$ (12)

Offsetting Derivative Instruments

LG&E enters into agreements pursuant to which it purchases or sells certain energy and other products. Under the agreements, upon termination of the agreement as a result of a default or other termination event, the non-defaulting party typically would have a right to set off amounts owed under the agreement against any other obligations arising between the two parties (whether under the agreement or not), whether matured or contingent and irrespective of the currency, place of payment or place of booking of the obligation.

LG&E has elected not to offset derivative assets and liabilities and not to offset net derivative positions against

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the right to reclaim cash collateral pledged (an asset) or the obligation to return cash collateral received (a liability) under derivatives agreements. The table below summarizes the derivative positions presented in the Balance Sheets where a right of setoff exists under these arrangements and related cash collateral received or pledged.

	Liabilities			
		Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Pledged	Net
December 31, 2015				
Treasury derivatives	$ 47	$ -	$ 9	$ 38
December 31, 2014				
Treasury derivatives	$ 81	$ -	$ 20	$ 61

Credit Risk-Related Contingent Features

Certain derivative contracts contain credit risk-related contingent features which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in LG&E’s credit ratings. Most of these features would require the transfer of additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these features also would allow the counterparty to require additional collateral upon each downgrade in credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade, and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent features require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization on derivative instruments in net liability positions.

Additionally, certain derivative contracts contain credit risk-related contingent features that require adequate assurance of performance be provided if the other party has reasonable concerns regarding LG&E’s performance obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" features.

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At December 31, 2015, derivative contracts in a net liability position that contain credit risk-related contingent features, collateral posted on those positions and the related effect of a decrease in credit ratings below investment grade are summarized as follows:

Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent features	$	28
Aggregate fair value of collateral posted on these derivative instruments		9
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)		19

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheet.

14. Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2015		December 31, 2014	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Coal contracts (a)	$ 124	$ 116	$ 124	$ 98
Land and transmission rights	7	1	7	1
Emission allowances (b)	1	-	1	-
OVEC power purchase agreement (c)	87	29	87	23
Total subject to amortization	$ 219	$ 146	$ 219	$ 122

(a) Gross carrying amount represents the fair value at the acquisition date of coal contracts with terms favorable to market recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 4 for additional information.
(b) Emission allowances are expensed when consumed or sold; therefore, there is no accumulated amortization.
(c) Gross carrying amount represents the fair value at the acquisition date of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to this contract, which is being amortized over the same period as the intangible asset, eliminating any income statement impact. See Note 4 for additional information.

Current intangible assets are included in "Other current assets" on the Balance Sheets. Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.

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Amortization expense was as follows:

	2015	2014
Intangible assets with regulatory offset	$ 24	$ 23

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2016	2017	2018	2019	2020
Intangible assets with regulatory offset	$ 14	$ 6	$ 6	$ 6	$ 6

15. Asset Retirement Obligations

LG&E's AROs are primarily related to the final retirement of assets associated with generating units. LG&E also has AROs related to natural gas mains and wells. LG&E's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. LG&E's accretion and depreciation expense are recorded as a regulatory asset, such that there is no earnings impact.

The changes in the carrying amounts of AROs were as follows.

	2015	2014
ARO at beginning of period	$ 74	$ 74
Accretion expense	5	4
Obligations incurred	3	-
Changes in estimated cash flow or settlement date	98	1
Obligations settled	(5)	(5)
ARO at end of period	175	74

LG&E recorded increases of $89 million to the existing AROs during 2015 as a result of an engineering study that was performed, in connection with the final CCR rule, providing clarity on projected CCR closure costs and revisions in the timing and amounts of future expected cash flows. Further increases to AROs or changes to current capital plans or to operating costs may be required as estimates of future cash flows are refined based on closure developments, groundwater monitoring results and regulatory or legal proceedings. In 2014, AROs were revalued primarily due to updates in the estimated cash flows for ash ponds based on updated cost estimates.

As of December 31, 2015, LG&E had $25 million of the ARO balances classified as current liabilities. These

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current liabilities are primarily related to CCR closure costs expected to be incurred in 2016. As of December 31, 2014, substantially all of the ARO balances are classified as noncurrent liabilities.

See Note 10 for information on the final CCR rule and Note 6 for information on the rate recovery applications with the KPSC.

16. New Accounting Guidance Pending Adoption

Accounting for Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance that establishes a comprehensive new model for the recognition of revenue from contracts with customers. This model is based on the core principle that revenue should be recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

For public business entities, this guidance can be applied using either a full retrospective or modified retrospective transition method, beginning in annual reporting periods after December 15, 2017 and interim periods within those years. Public business entities may early adopt this guidance in annual reporting periods beginning after December 15, 2016. LG&E expects to adopt this guidance effective January 1, 2018.

LG&E is currently assessing the impact of adopting this guidance, as well as the transition method it will use.

17. Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information

	December 31, 2015	December 31, 2014
Cash paid (received) during the period for:		
Income taxes	$ (81)	$ 65
Interest on borrowed money	40	38
Other cash paid for interest	8	8

18. Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $8 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense $4 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $8 million applicable to Common Utility Plant apportioned to Electric Operations.

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See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $3 million applicable to Common Utility Plant apportioned to Gas Operations.

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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4				168,075,992	168,075,992
5					
6					
7					
8					
9				185,363,790	185,363,790
10					

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,959,059,890	3,748,677,590
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,166,512,766	1,089,788,464
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,125,572,656	4,838,466,054
9	Leased to Others		
10	Held for Future Use	5,867,294	5,867,294
11	Construction Work in Progress	389,846,496	357,132,814
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,521,286,446	5,201,466,162
14	Accum Prov for Depr, Amort, & Depl	2,015,937,460	1,589,336,934
15	Net Utility Plant (13 less 14)	4,505,348,986	3,612,129,228
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,968,602,653	1,589,215,749
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	123	
21	Amort of Other Utility Plant	47,213,499	
22	Total In Service (18 thru 21)	2,015,816,275	1,589,215,749
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	121,185	121,185
29	Amortization		
30	Total Held for Future Use (28 & 29)	121,185	121,185
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,015,937,460	1,589,336,934

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
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Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
966,619,554				243,762,746	3
					4
					5
54,543,523				22,180,779	6
					7
1,021,163,077				265,943,525	8
					9
					10
22,415,538				10,298,144	11
					12
1,043,578,615				276,241,669	13
288,205,717				138,394,809	14
755,372,898				137,846,860	15
					16
					17
288,205,594				91,181,310	18
					19
123					20
				47,213,499	21
288,205,717				138,394,809	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
288,205,717				138,394,809	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	2,240	
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	2,240	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,795,932	
9	(311) Structures and Improvements	314,258,440	11,571,973
10	(312) Boiler Plant Equipment	1,802,942,672	496,205,639
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	246,410,650	21,013,808
13	(315) Accessory Electric Equipment	183,553,250	11,531,808
14	(316) Misc. Power Plant Equipment	21,473,912	-206,268
15	(317) Asset Retirement Costs for Steam Production	48,992,028	88,968,718
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,624,426,884	629,085,678
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	6	
28	(331) Structures and Improvements	7,684,665	193,180
29	(332) Reservoirs, Dams, and Waterways	16,944,847	93,336
30	(333) Water Wheels, Turbines, and Generators	62,019,115	146,991
31	(334) Accessory Electric Equipment	8,211,613	19,482
32	(335) Misc. Power PLant Equipment	1,192,295	-2,473
33	(336) Roads, Railroads, and Bridges	29,931	
34	(337) Asset Retirement Costs for Hydraulic Production	50,210	207,595
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	96,132,682	658,111
36	D. Other Production Plant		
37	(340) Land and Land Rights	15,541	2,958
38	(341) Structures and Improvements	15,004,440	13,395,472
39	(342) Fuel Holders, Products, and Accessories	8,141,511	37,972,274
40	(343) Prime Movers	162,751,106	25,710,079
41	(344) Generators	33,700,496	31,739,695
42	(345) Accessory Electric Equipment	21,854,879	7,714,630
43	(346) Misc. Power Plant Equipment	3,796,323	5,968
44	(347) Asset Retirement Costs for Other Production	32,135	52,129
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	245,296,431	116,593,205
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,965,855,997	746,336,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			2,240		2
					3
					4
			2,240		5
					6
					7
6,244		-1,761	6,787,927		8
30,881,150		-3,154,524	291,794,739		9
375,572,896			1,923,575,415		10
					11
43,111,774		-438,542	223,874,142		12
53,436,073			141,648,985		13
3,012,712		3,288	18,258,220		14
222,925			137,737,821		15
506,243,774		-3,591,539	2,743,677,249		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6		27
5,837			7,872,008		28
			17,038,183		29
48,705			62,117,401		30
10,626			8,220,469		31
			1,189,822		32
			29,931		33
			257,805		34
65,168			96,725,625		35
					36
		1,761	20,260		37
		3,593,066	31,992,978		38
			46,113,785		39
177,522			188,283,663		40
			65,440,191		41
23,086			29,546,423		42
			3,802,291		43
			84,264		44
200,608		3,594,827	365,283,855		45
506,509,550		3,288	3,205,686,729		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	11,149,391	
49	(352) Structures and Improvements	6,759,924	5,606,355
50	(353) Station Equipment	158,229,224	22,219,427
51	(354) Towers and Fixtures	41,356,638	2,603,548
52	(355) Poles and Fixtures	67,806,821	5,368,654
53	(356) Overhead Conductors and Devices	52,687,579	2,467,139
54	(357) Underground Conduit	2,278,628	
55	(358) Underground Conductors and Devices	7,425,136	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	218,085	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	347,911,426	38,265,123
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,123,724	
61	(361) Structures and Improvements	6,917,686	659,987
62	(362) Station Equipment	124,237,575	7,461,386
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	169,481,406	12,820,590
65	(365) Overhead Conductors and Devices	274,695,586	22,519,943
66	(366) Underground Conduit	82,578,818	848,557
67	(367) Underground Conductors and Devices	182,531,953	19,422,741
68	(368) Line Transformers	150,317,803	8,556,445
69	(369) Services	30,331,114	-62,785
70	(370) Meters	40,951,054	2,072,090
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	94,690,901	3,972,349
74	(374) Asset Retirement Costs for Distribution Plant	626,913	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,161,484,533	78,271,303
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights		
87	(390) Structures and Improvements		
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	9,484,702	436,881
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	5,850,090	644,896
92	(395) Laboratory Equipment	3,288	
93	(396) Power Operated Equipment	2,483,168	-47,403
94	(397) Communication Equipment	3,169,878	1,777,708
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	20,991,126	2,812,082
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	20,991,126	2,812,082
100	TOTAL (Accounts 101 and 106)	4,496,245,322	865,685,502
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	4,496,245,322	865,685,502

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,557			11,147,834		48
17,436			12,348,843		49
3,227,744			177,220,907		50
22,677			43,937,509		51
553,177			72,622,298		52
84,639			55,070,079		53
			2,278,628		54
			7,425,136		55
					56
			218,085		57
3,907,230			382,269,319		58
					59
23,070			4,100,654		60
81,049			7,496,624		61
854,431			130,844,530		62
					63
1,562,249			180,739,747		64
2,583,878			294,631,651		65
144,362			83,283,013		66
282,084			201,672,610		67
260,203			158,614,045		68
4			30,268,325		69
56,716			42,966,428		70
					71
					72
947,158			97,716,092		73
8,052	-96,570		522,291		74
6,803,256	-96,570		1,232,856,010		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
					86
					87
					88
5,579,494		-72,407	4,269,682		89
					90
142,874			6,352,112		91
		-3,288			92
425,796		72,407	2,082,376		93
			4,947,586		94
					95
6,148,164		-3,288	17,651,756		96
					97
					98
6,148,164		-3,288	17,651,756		99
523,368,200	-96,570		4,838,466,054		100
					101
					102
					103
523,368,200	-96,570		4,838,466,054		104

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Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 9 Column: f

Transfer of assets from retired Cane Run Steam Units 4, 5 and 6 for use in operation of Cane Run NGCC Unit 7 placed into service in June 2015.

Schedule Page: 204 Line No.: 12 Column: f

Transfer of assets from retired Cane Run Steam Units 4, 5 and 6 for use in operation of Cane Run NGCC Unit 7 placed into service in June 2015.

Schedule Page: 204 Line No.: 14 Column: c

Amounts temporarily classified to plant account Misc. Power Plant Equipment (316) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 32 Column: c

Amounts temporarily classified to plant account Misc. Power Plant Equipment (335) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 38 Column: f

Transfer of assets from retired Cane Run Steam Units 4, 5 and 6 for use in operation of Cane Run NGCC Unit 7 placed into service in June 2015.

Schedule Page: 204 Line No.: 69 Column: c

Amounts temporarily classified to plant account Services (369) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 74 Column: e

Adjustment due to changes in asset retirement cost estimates.

Schedule Page: 204 Line No.: 93 Column: c

Amounts temporarily classified to plant account Power Operated Equipment (396) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Five Tracts in or near Louisville, Kentucky	Various	Various	505,041
3				
4	US 42: Tract No. D152	01/31/2000	2017-2021	253,321
5				
6	Fegenbush Lane at the General Electric Plant	05/01/2012	2020-2024	519,009
7				
8	Tucker Station Distribution Substation -			
9	Blankenbaker Station Business Park, Tract 13	07/01/2012	2019-2023	745,731
10				
11	Distribution Drive at Riverport	04/01/2013	2021-2024	839,535
12				
13	Land at Green River Facility	11/01/2014	2021	211,409
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Site Development - Kentucky Street Substation D61			
23	and Kentucky Sub	06/30/1992	2021-2026	20,595
24				
25	Distribution Drive at Riverport	04/01/2013	2021-2024	2,772,653
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
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43				
44				
45				
46				
47	Total			5,867,294

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STEAM PRODUCTION MAJOR	
2	MC3 FGD AND FABRIC FILTER	224,789,741
3	TC CCP LANDFILL PH1 RAVINE - LG&E	8,285,854
4	MC 1 & 2 FGD AND FABRIC FILTER	4,856,558
5	MC GENERATOR STEP-UP TRANSFORMERS	3,923,046
6	TC1 SULFUR DIOXIDE REMOVAL SYSTEM REACTANT TANK ROOF	3,516,519
7	MC3 CONDENSER	2,543,211
8	MC2 ECONOMIZER	2,390,126
9	MC3 FINAL SUPER HEATER PENDANTS	1,937,678
10	MC4 BOILER LOWER SLOPE	1,806,466
11	MC4 ENVIRONMENTAL SPARES	1,472,154
12	MC4 FGD AND FABRIC FILTER	1,119,147
13	TC2 DRY SORBENT INJECTION SYSTEM - LG&E	1,091,097
14	MC3 BOILER EXTENDED ARCH	1,048,510
15	MC2 ENVIRONMENTAL SPARES	1,029,166
16	STEAM PRODUCTION MINOR	10,682,458
17		
18	HYDRAULIC POWER MAJOR	
19	OHIO FALLS REDEVELOPMENT #2	16,393,694
20	OHIO FALLS REDEVELOPMENT #4	5,205,056
21	OHIO FALLS REDEVELOPMENT #8	4,161,396
22	HYDRAULIC POWER MINOR	196,495
23		
24	OTHER PRODUCTION MAJOR	
25	BROWN SOLAR FACILITY - LG&E	4,126,017
26	CANE RUN 7 NGCC SPARES	1,076,500
27	OTHER PRODUCTION MINOR	1,590,693
28		
29	TRANSMISSION MAJOR	
30	KENZIG ROAD	11,142,362
31	PRIORITY REPLACEMENT TRANSMISSION LINES - LG&E	2,566,328
32	RELOCATE 345 ROW WIDENING	1,557,681
33	HARRODS CREEK - HARMONY LANDING P2 REPLACEMENT	1,079,321
34	RELOCATE 345 ROW BLUE LICK/MIDDLETOWN	1,000,086
35	TRANSMISSION MINOR	8,182,489
36		
37	DISTRIBUTION MAJOR	
38	PILC UNDERGROUND CABLE REPLACEMENT - LG&E	5,381,410
39	POLE INSPECTION AND REPLACEMENT PROJECT - LG&E	2,831,670
40	DSP MANSLICK SUBSTATION EXPANSION	2,181,441
41	PURCHASE DISTRIBUTION BUCKET TRUCKS - LG&E	1,517,839
42	DOWNTOWN NETWORK SWITCHES PROJECT	1,340,592
43	TOTAL	357,132,814

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION MINOR	15,110,013
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
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42		
43	TOTAL	357,132,814

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,008,999,108	2,008,923,672	75,436	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	113,830,566	113,830,566		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	400,229	400,229		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	45,749		45,749	
9	Fuel Stock	240,086	240,086		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	114,516,630	114,470,881	45,749	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	523,137,223	523,137,223		
13	Cost of Removal	23,470,794	23,470,794		
14	Salvage (Credit)	751,534	751,534		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	545,856,483	545,856,483		
16	Other Debit or Cr. Items (Describe, details in footnote):	11,908,656	11,908,656		
17					
18	Book Cost or Asset Retirement Costs Retired	-230,977	-230,977		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,589,336,934	1,589,215,749	121,185	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	843,050,648	842,929,463	121,185	
21	Nuclear Production				
22	Hydraulic Production-Conventional	8,761,689	8,761,689		
23	Hydraulic Production-Pumped Storage				
24	Other Production	107,168,895	107,168,895		
25	Transmission	147,408,544	147,408,544		
26	Distribution	475,589,914	475,589,914		
27	Regional Transmission and Market Operation				
28	General	7,357,244	7,357,244		
29	TOTAL (Enter Total of lines 20 thru 28)	1,589,336,934	1,589,215,749	121,185	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 8 Column: d

Depreciation on a facility not currently used in electric operations.

Schedule Page: 219 Line No.: 16 Column: c

Accrual for Depreciation on Asset Retirement Costs - (Other Regulatory Assets FERC 182.3)	$	11,096,795
Customer Payments Related to Construction Projects		811,861
Total Other Debit or Credit Items	$	11,908,656

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	OVEC (5.63%)			
2	Common Stock, $100 par value, 5,630 shares			
3	700 shares	11/18/52		70,000
4	700 shares	01/08/53		70,000
5	700 shares	02/25/53		70,000
6	700 shares	04/10/53		70,000
7	700 shares	05/12/53		70,000
8	1400 shares	07/27/53		140,000
9	730 shares	03/04/05		104,286
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
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27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 594,286		TOTAL	594,286

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		70,000		3
		70,000		4
		70,000		5
		70,000		6
		70,000		7
		140,000		8
		104,286		9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
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				28
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				30
				31
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				41
		594,286		42

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 1 Column: a

See Note 1 of Notes to Financial Statements under Cost Method Investment for a full description of the OVEC investment.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	66,567,149	71,040,238	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	30,219,899	27,006,495	Electric
8	Transmission Plant (Estimated)	2,477,123	3,003,481	Electric
9	Distribution Plant (Estimated)	2,733,410	2,038,317	Electric, Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	35,430,432	32,048,293	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	6,352,862	5,546,728	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	108,350,443	108,635,259	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 9 Column: b

	Balance End of Year
Electric	$ 2,290,278
Gas	443,132
Total Distribution	$ 2,733,410

Schedule Page: 227 Line No.: 9 Column: c

	Balance End of Year
Electric	$ 1,526,024
Gas	512,293
Total Distribution	$ 2,038,317

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	58,269.00	189	62,379.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	62,379.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	19,170.00	30		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	101,478.00	159	62,379.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	901.00		901.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	901.00			
40	Balance-End of Year			901.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	901.00	96		
45	Gains		96		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
62,379.00		62,379.00		1,621,854.00		1,867,260.00	189	1
								2
								3
						62,379.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						19,170.00	30	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
62,379.00		62,379.00		1,621,854.00		1,910,469.00	159	29
								30
								31
								32
								33
								34
								35
901.00		901.00		44,149.00		47,753.00		36
								37
								38
				901.00		1,802.00		39
901.00		901.00		43,248.00		45,951.00		40
								41
								42
								43
				901.00	26	1,802.00	122	44
					26		122	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	255.00	6,140		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	21,770.00		20,399.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchases - Open Market	37.00			
10					
11					
12					
13					
14					
15	Total	37.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	17,956.00	5,789		
19	Other:				
20	Charges to Account 549	704.00	351		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	3,402.00		20,399.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						255.00	6,140	1
								2
								3
						42,169.00		4
								5
								6
								7
								8
						37.00		9
								10
								11
								12
								13
								14
						37.00		15
								16
								17
						17,956.00	5,789	18
								19
						704.00	351	20
								21
								22
								23
								24
								25
								26
								27
								28
						23,801.00		29
								30
								31
								32
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								34
								35
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	System Impact Studies	3,721	561.6	3,721	561.6
3	Facility Studies	341	561.6	341	561.6
4					
5					
6					
7					
8					
9					
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13					
14					
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16					
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19					
20					
21	**Generation Studies**				
22					
23					
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40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	ASC 715 - Pension and Postretirement	214,538,462	31,966,740	Various	37,548,834	208,956,368
2	Asset Retirement Obligation - Electric	24,857,861	29,252,876	Various	740,182	53,370,555
3	Asset Retirement Obligation - Gas	3,388,874	1,947,945	230/403.1	1,713,247	3,623,572
4	Long-Term Interest Rate Swap	47,988,828		244	843,464	47,145,364
5	Long-Term Interest Rate Swap Non-LKE Affiliate	33,263,681	10,627,689	Various	825,497	43,065,873
6	Winter Storm 2009 - Electric (Aug-10 to Jul-20)	24,382,809		571/593	4,367,071	20,015,738
7	Winter Storm 2009 - Gas (Aug-10 to Jul-20)	93,627		880	16,769	76,858
8	ASC 740 - Income Taxes	13,792,117	14,319	282/283	279,552	13,526,884
9	Environmental Cost Recovery	3,840,000	10,486,000	440-445	1,020,000	13,306,000
10	Wind Storm 2008 (Aug-10 to Jul-20)	13,143,352		593	2,354,033	10,789,319
11	Swap Termination (Aug-10 to Apr-35)	7,901,428		930.2	388,659	7,512,769
12	Pension Gain/Loss Amortization - 15 Year		5,747,780	Various		5,747,780
13	Summer Storm 2011 (Jan-13 to Dec-17)	4,831,275		593	1,610,425	3,220,850
14	Unamortized Debt Expense (Aug-10 to Apr-35) - PAA	2,513,378		181	150,689	2,362,689
15	Performance-Based Rates	1,711,218	1,218,784	803	1,500,798	1,429,204
16	Gas Line Tracker		1,286,856	480-482		1,286,856
17	2014 Rate Case Expense-Electric (Jul-15 to Jun-18)	753,342	383,968	146/928	189,600	947,710
18	2014 Rate Case Expense-Gas (Jul-15 to Jun-18)	188,335	95,992	146/928	47,400	236,927
19	2012 Rate Case Expense-Electric (Jan-13 to Dec-15)	298,214		928	298,214	
20	2012 Rate Case Expense-Gas (Jan-13 to Dec-15)	94,960		928	94,960	
21	Carbon Mgmt Research Group (Aug-10 to Jul-20)	154,470	175,560	930.2	175,560	154,470
22	Fuel Adjustment Clause	1,562,000	2,088,000	440-445	3,650,000	
23	Coal Contracts (Nov-10 to Dec-15) - PAA	167,241		253	167,241	
24	2011 General Mgmt Audit-Electric (Jan-13 to Dec-15)	30,527		928	30,527	
25	2011 General Mgmt Audit-Gas (Jan-13 to Dec-15)	9,941		928	9,941	
26	Gas Supply Clause	13,794,977	2,074,932	803	15,869,909	
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43						
44	TOTAL	413,300,917	97,367,441		73,892,572	436,775,786

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: d
Accounts credited include 184, 228 and 926.

Schedule Page: 232 Line No.: 2 Column: d
Accounts credited include 230, 403.1 and 411.1.

Schedule Page: 232 Line No.: 5 Column: d
Accounts credited include 245, 254 and 427.

Schedule Page: 232 Line No.: 8 Column: a
The regulatory assets represent the future revenue impact from the reversal of deferred income tax liability required for a tax depreciation basis adjustment.

Schedule Page: 232 Line No.: 12 Column: d
Accounts credited include 182, 219, 232 and 926.

Schedule Page: 232 Line No.: 14 Column: a
Amounts in Unamortized Debt Expense (Aug-10 to Apr-35) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 232 Line No.: 23 Column: a
Amounts in Coal Contracts (Nov-10 to Dec-15) - PAA are purchase accounting adjustments (PAA) only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Goodwill	389,157,352				389,157,352
2						
3	OVEC Power Purchase Contract					
4	(Nov-10 to Mar-26) - PAA	63,856,830		254	5,756,807	58,100,023
5						
6	Coal Contracts					
7	(Nov-10 to Dec-16) - PAA	25,385,051		254	17,761,589	7,623,462
8						
9	Cane Run 7 LTPC Asset		1,863,539			1,863,539
10						
11	Valuation of SO2 Allowances					
12	(Nov-10 to Dec-40) - PAA	1,341,711		254	179,745	1,161,966
13						
14	Customer Credit Accounts					
15	Receivable	637,031		142	34,627	602,404
16						
17	Cellular Antenna Billable Chgs	52,381		Various	11,163	41,218
18						
19	Financing Expense	38,531	1,474			40,005
20						
21						
22						
23						
24						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	480,468,887				458,589,969

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: f

Goodwill is recorded as a result of PPL's acquisition of LKE in November 2010 and in conformity with purchase accounting journal entries filed in Docket No. AC11-83-000.

Schedule Page: 233 Line No.: 4 Column: f

Amounts in OVEC Power Purchase Contract (Nov-10 to Mar-26) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 233 Line No.: 7 Column: f

Amounts in Coal Contracts (Nov-10 to Dec-16) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 233 Line No.: 12 Column: f

Amounts in Valuation of SO2 Allowances (Nov-10 to Dec-40) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 233 Line No.: 17 Column: d

Accounts credited include 142, 143, and 172.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Net Operating Loss		63,995,723
3	Other Post Retirement & Employment Benefits	21,729,607	19,332,833
4	Regulatory Tax Adjustments	27,318,501	26,312,002
5	Interest Rate Swaps	38,174,183	27,113,871
6	Asset Retirement Obligation	24,896,125	66,343,208
7	Other - See Notes for Detail	48,701,107	41,839,523
8	TOTAL Electric (Enter Total of lines 2 thru 7)	160,819,523	244,937,160
9	Gas		
10	Net Operating Loss		12,189,661
11	Other Post Retirement & Employment Benefits	6,157,536	5,441,616
12	Regulatory Tax Adjustments	1,191,661	1,137,009
13	Interest Rate Swaps	9,543,449	6,778,370
14	Asset Retirement Obligation	8,315,032	7,216,620
15	Other - See Notes for Detail	6,236,962	8,770,232
16	TOTAL Gas (Enter Total of lines 10 thru 15	31,444,640	41,533,508
17	Other (Specify)	260,281	71,359
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	192,524,444	286,542,027

Notes

	Electric Amounts Beg. Bal.	Electric Amounts End. Bal.	Gas Amounts Beg. Bal.	Gas Amounts End. Bal.
Vacation Pay	$ 1,535,316	$ 1,469,420	$ 474,715	$ 458,240
Workers' Compensation	1,040,451	1,036,373	318,550	317,531
Air Permit Fees	1,237,732	1,074,561	-	-
Pensions	7,569,082	9,759,202	3,433,971	4,088,162
Bad Debts Reserve	452,678	326,884	167,407	133,969
Demand Side Management	45,018	173,083	364,236	1,400,392
Capitalized Gas Inventory	-	-	1,519,567	2,303,938
Other	2,038,877	2,473,446	92,635	194,839
Total Line No. 7/15 Without Purchase Accounting	13,919,154	16,312,969	6,371,081	8,897,071
Purchase Accounting Adjustments	34,781,953	25,526,554	(134,119)	(126,839)
Total Line No. 7/15 With Purchase Accounting	$48,701,107	$41,839,523	$6,236,962	$8,770,232

	Other Amounts Beginning	Other Amounts Ending
Non-Qualified Thrift	$ 260,281	$ 71,359
Line 17	$ 260,281	$ 71,359

Balance Beginning of Year	$192,524,444
Less Debits to	
Account 410.1	82,594,433
Account 410.2	230,967
Plus Credits to	
Account 411.1	178,235,155
Account 411.2	42,045
Other Balance Sheet Accounts	(1,434,217)
Balance at End of Year	$286,542,027

Note: Some beginning balance amounts were reordered from prior years' Form 1 ending balance amounts for

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

presentation purposes. The total beginning balance of deferrals did not change.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	Common Stock, Without Par Value	75,000,000		
3	Total Common	75,000,000		
4				
5	Preferred Stock			
6	Preferred Stock, $25 Par Value	1,720,000		
7	Preferred Stock, Without Par Value	6,750,000		
8	Total Preferred	8,470,000		
9				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
21,294,223	425,170,424					2
21,294,223	425,170,424					3
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Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 250 Line No.: 2 Column: d

There is no call price for common stock, without par value.

Schedule Page: 250 Line No.: 3 Column: a

The common stock of LG&E is owned by its parent company, LKE.

Schedule Page: 250 Line No.: 8 Column: a

No shares of preferred stock remain issued or outstanding.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211:	
2	Contributed Capital - Misc. - Balance January 1, 2015	1,521,167,368
3	Contributed Capital June 29, 2015	20,000,000
4	Contributed Capital December 30, 2015	70,000,000
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40	TOTAL	1,611,167,368

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 253 Line No.: 1 Column: a

See footnote data detail on Schedule Page: 112, Line No.: 7, Column: c.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Expenses on Common Stock	835,889
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22	TOTAL	835,889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221:		
2	Pollution Control Bonds:		
3	Jefferson County 2000 Series A, due 05/01/2027, Variable	25,000,000	883,831
4	Trimble County 2000 Series A, due 08/01/2030, Variable	83,335,000	1,154,826
5	Jefferson County 2001 Series A., due 09/01/2027, Variable	10,104,000	526,085
6	Jefferson County 2001 Series A, due 09/01/2026, Variable	22,500,000	242,653
7	Trimble County 2001 Series A, due 09/01/2026, 1.050%	27,500,000	263,855
8	Jefferson County 2001 Series B, due 11/01/2027, 1.350%	35,000,000	281,244
9	Trimble County 2001 Series B, due 11/01/2027, 1.350%	35,000,000	281,283
10	Trimble County 2002 Series A, due 10/01/2032, Variable	41,665,000	1,112,006
11	Louisville Metro 2003 Series A, due 10/01/2033, 1.650%	128,000,000	4,792,737
12	Louisville Metro 2005 Series A, due 02/01/2035, 2.200%	40,000,000	1,428,142
13	Trimble County 2007 Series A, due 06/01/2033, 4.600%	60,000,000	1,239,280
14	Louisville Metro 2007 Series A, due 06/01/2033, 1.150%	31,000,000	938,023
15	Louisville Metro 2007 Series B, due 06/01/2033, 1.600%	35,200,000	1,085,694
16	Interest Rate Swaps:		
17			
18	First Mortgage Bonds:		
19	2010 due 11/15/2015, 1.625%	250,000,000	2,563,689
20			882,500 D
21	2010 due 11/15/2040, 5.125%	285,000,000	3,570,026
22			3,100,600 D
23	2013 due 11/15/2043, 4.650%	250,000,000	2,742,758
24			1,800,000 D
25	2015 due 10/1/2025, 3.300% (Case No.2014-00082 June 16, 2014)	300,000,000	2,372,643
26			129,000 D
27	2015 due 10/1/2045, 4.375% (Case No.2014-00082 June 16, 2014)	250,000,000	2,568,352
28			207,500 D
29	TOTAL ACCOUNT 221	1,909,304,000	34,166,727
30			
31			
32			
33	TOTAL	1,907,241,333	34,166,727

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/19/2000	05/01/2027	05/19/2000	05/01/2027	25,000,000	199,338	3
08/09/2000	08/01/2030	08/09/2000	08/01/2030	83,335,000	157,411	4
09/11/2001	09/01/2027	09/11/2001	09/01/2027	10,104,000	15,095	5
03/06/2002	09/01/2026	03/06/2002	09/01/2026	22,500,000	51,639	6
03/06/2002	09/01/2026	03/06/2002	09/01/2026	27,500,000	288,750	7
03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	472,500	8
03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	472,500	9
10/23/2002	10/01/2032	10/23/2002	10/01/2032	41,665,000	100,930	10
11/20/2003	10/01/2033	11/20/2003	10/01/2033	128,000,000	2,112,000	11
04/13/2005	02/01/2035	04/13/2005	02/01/2035	40,000,000	880,000	12
04/26/2007	06/01/2033	04/26/2007	06/01/2033	60,000,000	2,760,000	13
04/26/2007	06/01/2033	04/26/2007	06/01/2033	31,000,000	356,500	14
04/26/2007	06/01/2033	04/26/2007	06/01/2033	35,200,000	563,200	15
					7,942,291	16
						17
						18
11/16/2010	11/15/2015	11/16/2010	11/15/2015		3,543,403	19
		11/16/2010	11/15/2015			20
11/16/2010	11/15/2040	11/16/2010	11/15/2040	285,000,000	14,606,250	21
		11/16/2010	11/15/2040			22
11/14/2013	11/15/2043	11/14/2013	11/15/2043	250,000,000	10,191,295	23
			11/15/2043			24
9/28/2015	10/01/2025	09/28/2015	10/01/2025	300,000,000	2,923,284	25
			10/01/2025			26
9/28/2015	10/01/2045	09/28/2015	10/01/2045	250,000,000	3,082,166	27
			10/01/2045			28
				1,659,304,000	50,718,552	29
						30
						31
						32
				1,657,713,446	50,809,850	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 222:		
2	TOTAL ACCOUNT 222		
3			
4			
5	ACCOUNT 223:		
6	TOTAL ACCOUNT 223		
7			
8	ACCOUNT 224:		
9	Purchase Accounting Adjustments for Fair Value Measurement		
10	Trimble County 2007 Series A, due 06/01/2033, 4.600%	-2,062,667	
11			
12	TOTAL ACCOUNT 224	-2,062,667	
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31			
32			
33	TOTAL	1,907,241,333	34,166,727

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
		11/01/2010	06/01/2033	-1,590,554	91,298	10
						11
				-1,590,554	91,298	12
						13
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						18
						19
						20
						21
						22
						23
						24
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						32
				1,657,713,446	50,809,850	33

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 1 Column: a

Per instruction 9 concerning the treatment of unamortized debt expense, premium or discount, original debt premiums and expenses are being amortized over the lives of the related issues and remarketing expenses are being amortized through the put dates of the remarketed bonds.

Schedule Page: 256 Line No.: 2 Column: a

Pollution control series bonds are obligations of LG&E, issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds.

Schedule Page: 256 Line No.: 16 Column: a

As of December 31, 2015, the company had in effect four interest-rate swap agreements to hedge its exposure to tax exempt rates related to Pollution Control Bonds, Variable Rate Series. The Company’s position under the swap agreements are to pay a fixed rate and receive a variable rate based on the Securities Industry and Financial Markets Association Index or London Interbank Offered Rate (LIBOR). The specifics for each swap agreement related to notional amounts, maturity dates, payable and receivable positions are as follows:

Notional Amount	Maturity	Payable	Receivable
$83,335,000	11/01/2020	Fixed 5.495%	SIFMA Index
$32,000,000	10/01/2033	Fixed 3.657%	68% of 1 mo LIBOR
$32,000,000	10/01/2033	Fixed 3.645%	68% of 1 mo LIBOR
$32,000,000	10/01/2033	Fixed 3.695%	68% of 1 mo LIBOR

By Order in Case No. 2014-00082 on June 16, 2014, LG&E was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $550 million and enter into hedging agreements to lock in interest rates for debt to be issued in 2015. LG&E entered into hedging agreements totaling $500 million for the two bonds and in September 2015 when the debt was issued, the swaps were settled at a loss of $43,688,302. The loss is being amortized over the life of the debt to which it relates.

Schedule Page: 256 Line No.: 18 Column: a

Proceeds from LG&E’s First Mortgage Bonds issued in 2010 were used to repay the loans from a PPL subsidiary and for general corporate purposes. Proceeds from LG&E's First Mortgage Bonds issued in 2013 were used for capital expenditures and general corporate purposes. Proceeds from LG&E’s First Mortgage Bonds issued in 2015 were used to pay maturing debt, pay down short term debt, and general corporate purposes. The first mortgage bonds were issued at a discount.

As of December 31, 2015, all of the Company’s long-term debt is collateralized by a first mortgage lien on substantially all of the assets of the Company in Kentucky.

Schedule Page: 256 Line No.: 25 Column: a

By Order in Case No. 2014-00082 on June 16, 2014, LG&E was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $550 million and enter into hedging agreements to lock in interest rates for debt to be issued in 2015. LG&E entered into hedging agreements totaling $300 million for the 10 year bond and $250 million for the 30 year bond. Debt was issued in September 2015, totaling $300 million in 10 year First Mortgage Bonds and $250 million in 30 year First Mortgage Bonds. The swaps were settled at a loss of $14,076,899 related to the $300 million, 10 year First Mortgage Bonds.

Schedule Page: 256 Line No.: 27 Column: a

By Order in Case No. 2014-00082 on June 16, 2014, LG&E was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $550 million and enter into hedging agreements to lock in interest rates for debt to be issued in 2015. LG&E entered into hedging agreements totaling $300 million for the 10 year bond and $250 million for

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FOOTNOTE DATA

the 30 year bond. Debt was issued in September 2015, totaling $300 million in 10 year First Mortgage Bonds and $250 million in 30 year First Mortgage Bonds. The swaps were settled at a loss of $29,611,403 related to the $250 million, 30 year First Mortgage Bonds.

Schedule Page: 256.1 Line No.: 5 Column: a

LG&E did not have long-term notes with associated companies in 2015.

Schedule Page: 256.1 Line No.: 8 Column: a

Upon completion of the acquisition by PPL, push-down accounting was used, resulting in adjustments to certain of the Company’s assets and liabilities to reflect their estimated fair values on the acquisition date.

The Trimble County 2007 Series A pollution control bond, listed below, was fair valued and continues to be amortized as a result of the PPL acquisition:

Bond Issue	(221) Principal	(224) Fair Value Adjustment	Total Purchase Accounting
Trimble County 2007 Series A, due 6/1/2033, 4.600%	$60,000,000	($2,062,667)	$57,937,333

The purchase accounting adjustment was recorded to Other Long-Term Debt Account (224). Amortization is recorded to Interest on Long-Term Debt Account (427).

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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	185,363,790
2		
3		
4	Taxable Income Not Reported on Books	
5	See footnote	27,675,875
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	368,813,342
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	15,560,689
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	613,419,635
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-47,127,317
28	Show Computation of Tax:	
29	35% Rounded	-16,494,561
30	Add: Adjustment of Prior Years' Taxes & Other	980,676
31		
32	Total:	-15,513,885
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Purchased Gas Adjustment	$ 14,489,662
Contribution in Aid of Construction	6,245,359
Fuel Adjustment Clause	3,948,000
Demand Side Management	2,992,854
Total	$ 27,675,875

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Utility Operating Income	$ (13,679,235)
Other Income and Deductions	(1,834,650)
Provision for Deferred Income Taxes	127,672,181
Net Operating Loss	217,672,526
Capitalized Interest	16,079,287
Storm Damages	8,348,297
Obsolete Inventory	8,200,000
Performance Incentive	1,978,479
Loss on Reacquired Debt - Amortization	1,167,401
Prepaid Insurance	1,376,318
Nondeductible Expenses	604,701
Other	1,136,739
Total Without Purchase Accounting	368,722,044
Purchase Accounting Adjustments - FMV Bonds	91,298
Total	$ 368,813,342

Schedule Page: 261 Line No.: 15 Column: b

Environmental Cost Recovery	$ 9,466,000
Gas Line Tracker	3,950,650
Amortization of Investment Tax Credit	1,338,634
Customer Advances for Construction	805,405
Total	$ 15,560,689

Schedule Page: 261 Line No.: 20 Column: b

Tax over Book Depreciation, Net and Repairs	$ 535,298,202
Interest Rate Swaps	44,499,577
Cost of Removal	27,915,563
Capitalized Gas Inventory	1,900,000
Current State Income Tax	963,329
Other	2,842,964
Total	$ 613,419,635

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income			-85,281,871	-85,281,871	
3	FICA	775,836		7,864,673	7,696,359	
4						
5	Kentucky & Other States:					
6	Income	1,948,239		3,325,113	4,288,442	
7	Public Service Commission		1,358,178	2,779,351	2,842,346	
8	Use (Kentucky)	650,284		6,663,007	6,567,321	
9	Use (Indiana)			58,004	58,004	
10						
11	Federal & Kentucky:					
12	Unemployment Insurance	171,637		144,970	269,442	
13						
14	Miscellaneous			94,810	94,810	
15						
16	Kentucky & Indiana:					
17	Property Taxes	15,323,569		25,868,786	23,989,031	
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	18,869,565	1,358,178	-38,483,157	-39,476,116	

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		-12,314,375			-72,967,496	2
944,150		6,749,475			1,115,198	3
						4
						5
984,910		1,867,677			1,457,436	6
	1,421,173	2,121,000			658,351	7
745,970					6,663,007	8
					58,004	9
						10
						11
47,165		159,007			-14,037	12
						13
		74,900			19,910	14
						15
						16
17,203,324		19,235,773			6,633,013	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
19,925,519	1,421,173	17,893,457			-56,376,614	41

BLANK

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FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

Segregation of Other	Column Other (l)	Page 115 Gas Acct. 408.1 - 409.1	Page 117 Other Inc & Deductions 408.2 – 409.2	Other Accounts
Federal:				
Income	$(72,967,496)	$(1,364,860)	$(1,834,650)	$(69,767,986)
FICA	1,115,198	1,891,430	-	(776,232)
Kentucky & Other States:				
Income	1,457,436	1,792,023	(334,587)	-
PSC	658,351	658,351	-	-
6% Use (Kentucky)	6,663,007	-	-	6,663,007
7% Use (Indiana)	58,004	-	-	58,004
Federal & Kentucky:				
Unemployment Ins	(14,037)	33,279	-	(47,316)
Miscellaneous	19,910	19,910	-	-
Kentucky & Indiana:				
Property Taxes	6,633,013	6,456,922	7,003	169,088
Total	$(56,376,614)	$ 9,487,055	$(2,162,234)	$(63,701,435)

Reconciliation to Schedule Page: 114-115, Line No.: 14-16:

Federal Income:		State Income:		Other:	
Electric	$(12,314,375)	Electric	$1,867,677	Elec Total	$17,893,457
Gas	(1,364,860)	Gas	1,792,023	Gas Total	9,487,055
Total	$(13,679,235)	Total	$3,659,700	Less Federal	13,679,235
				Less State	(3,659,700)
				Total	$37,400,047

Schedule Page: 262 Line No.: 2 Column: b

Balance at Beginning of Year totaling $74,058,751 was reclassified to Accounts Receivable from Associated Companies (146).

Balance at Ending of Year totaling $4,290,765 was reclassified to Accounts Receivable from Associated Companies (146).

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	15%	21,663,195			411.4	416,600	
7	Various	14,098,865			411.4	844,314	
8	TOTAL	35,762,060				1,260,914	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16	Gas Utility	220,045			411.4	77,720	
17	TOTAL	220,045				77,720	
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47		35,982,105			411.4	1,338,634	
48	Grand Total	35,982,105				1,338,634	

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
21,246,595	54 Years		6
13,254,551	32 Years		7
34,501,146			8
			9
			10
			11
			12
			13
			14
			15
142,325	33 Years		16
142,325			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
34,643,471			47
34,643,471			48

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Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Long-Term Retainage	10,663,076	232	8,688,394		1,974,682
2						
3	Corporate Headquarters Lease					
4	(Jul-12 to Dec-25)	1,159,909			41,576	1,201,485
5						
6	Prepaid Transmission System Fee:					
7	MCI Telecom (Apr-09 to Apr-29)	484,483	454	36,796		447,687
8						
9	Uncertain Tax Position - Federal	201,769				201,769
10						
11	Deferred Compensation	669,103	146	485,659		183,444
12						
13	Clearing Accounts Transferred					
14	from Other Deferred Debits	20,457	184	10,913,873	10,901,978	8,562
15						
16	Brown CT Long-Term Service					
17	Agreement	1,410,566	107/232	1,410,566		
18						
19	Valuation of Coal Contracts					
20	(Nov-10 to Dec-15) - PAA	167,241	182.3	167,241		
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	14,776,604		21,702,529	10,943,554	4,017,629

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 269 Line No.: 20 Column: f

Amounts in Coal Contracts (Nov-10 to Dec-15) - PAA are purchase accounting adjustments (PAA) only.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	544,662,487	264,478,892	71,085,235
3	Gas	166,504,147	52,659,691	18,708,363
4				
5	TOTAL (Enter Total of lines 2 thru 4)	711,166,634	317,138,583	89,793,598
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	711,166,634	317,138,583	89,793,598
10	Classification of TOTAL			
11	Federal Income Tax	634,595,824	288,013,423	77,983,248
12	State Income Tax	76,570,810	29,125,160	11,810,350
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		254	447,647	254	605,578	738,214,075	2
		254	150,704	254	158,825	200,463,596	3
							4
			598,351		764,403	938,677,671	5
							6
							7
							8
			598,351		764,403	938,677,671	9
							10
			517,313		426,903	844,535,589	11
			81,038		337,500	94,142,082	12
							13

NOTES (Continued)

BLANK

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: b

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2014, is $15,226,417.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2014, is $(1,280,034).

Schedule Page: 274 Line No.: 2 Column: k

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2015, is $45,582,062.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2015, is $(1,437,965).

Schedule Page: 274 Line No.: 3 Column: b

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2014, is $6,996,760.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2014, is $1,651,689.

Schedule Page: 274 Line No.: 3 Column: k

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2015, is $5,807,050.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2015, is $1,643,568.

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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Loss on Reacquired Debt	6,474,981	20,568	401,574
4	Storm Damages	16,477,039	174,962	3,415,928
5	Interest Rate Swaps	25,285,859	16,391,594	13,603,638
6	Asset Retirement Obligation	9,669,707	11,690,205	598,767
7	Pension - Regulatory Asset	47,623,740	5,092,902	3,029,977
8	Other	49,684,459	2,110,597	15,522,220
9	TOTAL Electric (Total of lines 3 thru 8)	155,215,785	35,480,828	36,572,104
10	Gas			
11	Loss on Reacquired Debt	539,181	3,947	77,060
12	Interest Rate Swaps	6,321,367	4,097,898	3,400,909
13	Asset Retirement Obligation	1,318,272	230,407	139,111
14	Purchased Gas	3,558,088	4,459,915	10,096,394
15	Pension - Regulatory Asset	14,225,272	1,521,257	905,058
16	Other	486,466	2,214,349	1,038,969
17	TOTAL Gas (Total of lines 11 thru 16)	26,448,646	12,527,773	15,657,501
18	Other			
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	181,664,431	48,008,601	52,229,605
20	Classification of TOTAL			
21	Federal Income Tax	153,644,210	41,356,991	44,926,940
22	State Income Tax	28,020,221	6,651,610	7,302,665
23	Local Income Tax			

NOTES

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						6,093,975	3
						13,236,073	4
						28,073,815	5
						20,761,145	6
						49,686,665	7
		182	108,745	182	5,570	36,169,661	8
			108,745		5,570	154,021,334	9
							10
						466,068	11
						7,018,356	12
						1,409,568	13
						-2,078,391	14
						14,841,471	15
		190	393,206	190	20,140	1,288,780	16
			393,206		20,140	22,945,852	17
							18
			501,951		25,710	176,967,186	19
							20
			428,495		25,710	149,671,476	21
			73,456			27,295,710	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: b

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the balance at December 31, 2014:

Prepaid Insurance	$ 1,030,230
Management Audit Fees	11,874
Rate Case Expenses	409,054
Regulatory Tax Adjustments	5,365,133
Swap Termination	3,073,654
FAC Under Recovery	607,619
Post Retirement - Regulatory Asset	3,784,824
Other	99,997

Total for Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$14,382,385
Purchase Accounting Adjustments	35,302,074

Total for Accumulated Deferred Income Taxes - Other (283)	$49,684,459

Schedule Page: 276 Line No.: 8 Column: c

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of LG&E by PPL in November 2010. The following reflects the activity during the year charged to Provision for Deferred Income Taxes (410.1):

Amounts Debited to Account 410.1:	
Prepaid Insurance	$ 332,333
Management Audit Fees	2,834
Rate Case Expenses	91,425
Swap Termination	8,162
FAC Under Recovery	640,622
Post Retirement - Regulatory Asset	386,176
Other	147,872

Total for Amounts Debited to Account (410.1) Without Purchase Accounting	$ 1,609,424
Purchase Accounting Adjustment	501,173

Total for Amounts Debited to Account (410.1)	$ 2,110,597

Schedule Page: 276 Line No.: 8 Column: d

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of LG&E by PPL in November 2010. The following reflects the activity during the year charged to Provision for Deferred Income Taxes-Cr. (411.1):

Amounts Credited to Account 411.1:	
Prepaid Insurance	$ 765,997
Management Audit Fees	14,708
Rate Case Expenses	131,821
Swap Termination	159,351
FAC Under Recovery	2,176,394
Post Retirement - Regulatory Asset	2,409,398
Other	79,744

Total for Amounts Credited to Account (411.1) Without Purchase Accounting	$ 5,737,413
Purchase Accounting Adjustment	9,784,807

Total for Amounts Credited to Account (411.1)	$15,522,220

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: h

Regulatory Tax Adjustments	$ 108,745

Schedule Page: 276 Line No.: 8 Column: j

Regulatory Tax Adjustments	$ 5,570

Schedule Page: 276 Line No.: 8 Column: k

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL in November 2010. The following reflects the balance at December 31, 2015:

Prepaid Insurance	$ 596,566
Rate Case Expenses	368,658
Regulatory Tax Adjustments	5,261,958
Swap Termination	2,922,465
FAC Under Recovery	(928,153)
Post Retirement - Regulatory Asset	1,761,602
Other	168,125

Total for Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$10,151,221
Purchase Accounting Adjustments	26,018,440

Total for Accumulated Deferred Income Taxes - Other (283)	$36,169,661

Schedule Page: 276 Line No.: 16 Column: b

The following reflects the balance in Accumulated Deferred Income Taxes - Other (283) at December 31, 2014:

Prepaid Insurance	$ 241,658
Management Audit Fees	3,869
Rate Case Expenses	110,202
Gas Line Tracker - Regulatory Asset	(1,036,216)
Storm Damages	36,421
Post Retirement - Regulatory Asset	1,130,532

Total for Accumulated Deferred Income Taxes - Other (283)	$ 486,466

Schedule Page: 276 Line No.: 16 Column: c

The following reflects the activity during the year charged to Provision for Deferred Income Taxes (410.1):

Amounts Debited to Account 410.1:	
Prepaid Insurance	$ 77,959
Management Audit Fees	922
Rate Case Expenses	5,587
Gas Line Tracker - Regulatory Asset	2,012,973
Storm Damages	1,557
Post Retirement - Regulatory Asset	115,351

Total Amounts Debited to Account 410.1	$ 2,214,349

Schedule Page: 276 Line No.: 16 Column: d

The following reflects the activity during the year charged to Provision for Deferred Income Taxes-Cr. (411.1):

Amounts Credited to Account 411.1:	
Prepaid Insurance	$ 179,679
Management Audit Fees	4,791
Rate Case Expenses	23,624
Gas Line Tracker - Regulatory Asset	103,104

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Storm Damages	8,080
Post Retirement - Regulatory Asset	719,691

Total Amounts Credited to Account 411.1	$ 1,038,969

Schedule Page: 276 Line No.: 16 Column: h

Gas Line Tracker - Regulatory Asset	$ 393,206

Schedule Page: 276 Line No.: 16 Column: j

Gas Line Tracker - Regulatory Asset	$ 20,140

Schedule Page: 276 Line No.: 16 Column: k

The following reflects the balance in Accumulated Deferred Income Taxes - Other (283) at December 31, 2015:

Prepaid Insurance	$ 139,938
Rate Case Expenses	92,165
Gas Line Tracker - Regulatory Asset	500,587
Storm Damages	29,898
Post Retirement - Regulatory Asset	526,192

Total for Accumulated Deferred Income Taxes - Other (283)	$ 1,288,780

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS: Account Credited (c)	DEBITS: Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	OVEC Pwr Purchase Contract (Nov-10 to Mar-26) - P	63,856,830	186	5,756,807		58,100,023
2	Forward Starting Swap	41,414,924	427	1,433,704		39,981,220
3	ASC 740 - Income Taxes	37,308,800	190/282	2,080,128	690,868	35,919,540
4	Coal Contracts (Nov-10 to Dec-16) - PAA	25,385,051	186	17,761,589		7,623,462
5	Gas Supply Clause	6,359,438	803	18,141,117	18,553,788	6,772,109
6	DSM Cost Recovery	1,052,065	Various	5,638,808	8,631,662	4,044,919
7	Fuel Adjustment Clause		440-445	1,378,859	3,764,859	2,386,000
8	Emission Allowances (Nov-10 to Dec-40) - PAA	1,341,711	186	338,610	158,865	1,161,966
9	MISO Exit Fee Refund	686,188	575.7	297,828	2,798	391,158
10	Off-System Sales Tracker		440-445	65,778	118,112	52,334
11	Gas Line Tracker	2,663,794	480-482	2,663,794		
12						
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41	TOTAL	180,068,801		55,557,022	31,920,952	156,432,731

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 Column: a
Amounts in OVEC Pwr Purchase Contract (Nov-10 to Mar-26) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 278 Line No.: 3 Column: a
The regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

Schedule Page: 278 Line No.: 4 Column: a
Amounts in Coal Contracts (Nov-10 to Dec-16) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 278 Line No.: 6 Column: c
Accounts debited include 440-445 and 480-482.

Schedule Page: 278 Line No.: 8 Column: a
Amounts in Emission Allowances (Nov-10 to Dec-40) - PAA are purchase accounting adjustments (PAA) only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	425,948,298	419,063,081
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	359,004,552	343,407,017
5	Large (or Ind.) (See Instr. 4)	189,367,016	182,233,761
6	(444) Public Street and Highway Lighting	3,230,561	2,702,454
7	(445) Other Sales to Public Authorities	99,216,038	94,996,188
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,076,766,465	1,042,402,501
11	(447) Sales for Resale	51,201,789	118,088,832
12	TOTAL Sales of Electricity	1,127,968,254	1,160,491,333
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,127,968,254	1,160,491,333
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,668,174	2,437,193
17	(451) Miscellaneous Service Revenues	1,611,663	1,546,535
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,143,777	3,690,979
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	1,297,995	1,707,947
22	(456.1) Revenues from Transmission of Electricity of Others	8,387,540	7,770,433
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	18,109,149	17,153,087
27	TOTAL Electric Operating Revenues	1,146,077,403	1,177,644,420

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
4,080,624	4,157,326	353,419	350,588	2
				3
3,746,408	3,714,091	42,694	42,261	4
2,775,815	2,773,972	476	440	5
19,334	17,122	659	656	6
1,144,848	1,154,653	4,123	4,097	7
				8
				9
11,767,029	11,817,164	401,371	398,042	10
1,735,184	3,556,567	14	13	11
13,502,213	15,373,731	401,385	398,055	12
				13
13,502,213	15,373,731	401,385	398,055	14

Line 12, column (b) includes $ -243,092 of unbilled revenues.
Line 12, column (d) includes -52,061 MWH relating to unbilled revenues

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 21 Column: b

Items which compose Other Electric Revenues (456) year-to-date activity:

2015 invoices to Kosmos	$ 1,008,563
Other items less than $250,000	289,432
Total for Other Electric Revenues (456)	$ 1,297,995

Schedule Page: 300 Line No.: 21 Column: c

Items which compose Other Electric Revenues (456) year-to-date activity:

2014 invoices to Kosmos	$ 1,238,413
Other items less than $250,000	469,534
Total for Other Electric Revenues (456)	$ 1,707,947

Schedule Page: 300 Line No.: 22 Column: b

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

2015 invoices to Owensboro Municipal Utilities	$ 2,574,199
2015 invoices to East Kentucky Power Cooperative	2,111,065
2015 invoices to Kentucky Municipal Power Agency	881,131
2015 invoices to City of Frankfort	704,872
2015 invoices to Tennessee Valley Authority	408,343
2015 invoices to Kentucky Utilities Company	380,782
2015 invoices to City of Madison	294,755
Other items less than $250,000 each	1,032,393
Total for Revenues from Transmission of Electricity of Others (456.1)	$ 8,387,540

Schedule Page: 300 Line No.: 22 Column: c

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

2014 invoices to Owensboro Municipal Utilities	$ 2,387,283
2014 invoices to East Kentucky Power Cooperative	2,246,750
2014 invoices to Kentucky Municipal Power Agency	847,207
2014 invoices to City of Frankfort	663,271
2014 invoices to Kentucky Utilities Company	276,241
Other items less than $250,000 each	1,349,681
Total for Revenues from Transmission of Electricity of Others (456.1)	$ 7,770,433

Schedule Page: 300 Line No.: 1 Column: $

The net unbilled revenue represents the following:

Base Revenue	$ (2,532,000)
Environmental Cost Recovery Accrual	9,466,000
Fuel Adjustment Clause Accrual	(3,948,000)
Demand Side Management Accrual	(3,176,758)
Off-System Sales Tracker Accrual	(52,334)
Net Unbilled	$ (243,092)

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue of (52,061) MWH represents the net change of unbilled MWH from the previous period; as a result, it could be positive or negative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 440					
2	Residential Service (RS)	4,118,394	429,072,409	356,621	11,548	0.1042
3	Volunteer Fire Department (VFD)	374	35,183	2	187,000	0.0941
4	General Service (GS)	169	22,832	503	336	0.1351
5	Lighting Service (LS)	2,838	704,797	3,888	730	0.2483
6	Restricted Lighting Service (RLS)	2,378	489,228	2,317	1,026	0.2057
7	Low Emission Vehicle (LEV)	217	21,358	9	24,111	0.0984
8	Residential Time of Day (RTOD)	185	17,575	13	14,231	0.0950
9	Duplicate Customers			-9,934		
10						
11	Reclassifications and Adjustments		-12,493			
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36	Subtotal	4,124,555	430,350,889	353,419	11,670	0.1043
37	Unbilled	-43,931	-4,402,591			0.1002
38	Total	4,080,624	425,948,298	353,419	11,546	0.1044
39						
40						
41	TOTAL Billed	11,819,090	1,077,009,557	401,371	29,447	0.0911
42	Total Unbilled Rev.(See Instr. 6)	-52,061	-243,092	0	0	0.0047
43	TOTAL	11,767,029	1,076,766,465	401,371	29,317	0.0915

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 442					
2	Residential Service (RS)	156	16,068	170	918	0.1030
3	General Service (GS)	1,224,501	138,499,480	41,138	29,766	0.1131
4	Power Service (PS)	1,804,880	160,773,872	2,581	699,295	0.0891
5	Ind Time-of-Day Secondary (ITODS)	120,052	10,191,377	37	3,244,649	0.0849
6	Ind Time-of-Day Primary (ITODP)	691,714	46,834,728	31	22,313,355	0.0677
7	Com Time-of-Day Primary (CTODP)	87,250	6,803,869	13	6,711,538	0.0780
8	Com Time-of-Day Secondary	334,709	26,602,310	111	3,015,396	0.0795
9	Retail Transmission Service (RTS)	923,297	51,302,659	7	131,899,571	0.0556
10	Lighting Service (LS)	33,673	5,913,069	7,154	4,707	0.1756
11	Restricted Lighting Service (RLS)	14,171	3,688,686	2,631	5,386	0.2603
12	Lighting Energy Service (LE)	2	165	16	125	0.0825
13	Time-of-Day Primary (TODP)	773,928	53,103,649	44	17,589,273	0.0686
14	Time-of-Day Secondary (TODS)	518,326	41,378,272	158	3,280,544	0.0798
15	Duplicate Customers			-10,921		
16						
17	Reclassifications and Adjustments		-334,926			
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37	Subtotal	6,526,659	544,773,278	43,170	151,185	0.0835
38	Unbilled	-4,436	3,598,290			-0.8112
39	Total	6,522,223	548,371,568	43,170	151,082	0.0841
40						
41	TOTAL Billed	11,819,090	1,077,009,557	401,371	29,447	0.0911
42	Total Unbilled Rev.(See Instr. 6)	-52,061	-243,092	0	0	0.0047
43	TOTAL	11,767,029	1,076,766,465	401,371	29,317	0.0915

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 444					
2	General Service (GS)	184	18,764	10	18,400	0.1020
3	Lighting Service (LS)	8,186	1,272,838	439	18,647	0.1555
4	Restricted Lighting Service (RLS)	6,518	1,470,759	566	11,516	0.2256
5	Lighting Energy Service (LE)	2,021	141,422	65	31,092	0.0700
6	Traffic Energy Service (TE)	2,139	212,352	22	97,227	0.0993
7	Duplicate Customers			-443		
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36						
37	Subtotal	19,048	3,116,135	659	28,904	0.1636
38	Unbilled	286	114,426			0.4001
39	Total	19,334	3,230,561	659	29,338	0.1671
40						
41	TOTAL Billed	11,819,090	1,077,009,557	401,371	29,447	0.0911
42	Total Unbilled Rev.(See Instr. 6)	-52,061	-243,092	0	0	0.0047
43	TOTAL	11,767,029	1,076,766,465	401,371	29,317	0.0915

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 445					
2	Residential Service (RS)	1,088	114,263	332	3,277	0.1050
3	Volunteer Fire Department (VFD)	1	245	1	1,000	0.2450
4	General Service (GS)	106,123	11,491,550	2,073	51,193	0.1083
5	Power Service (PS)	307,558	30,697,964	306	1,005,092	0.0998
6	Ind Time-of-Day Secondary (ITODS)	5,689	466,809	2	2,844,500	0.0821
7	Ind Time-of-Day Primary (ITODP)	45,318	3,418,502	4	11,329,500	0.0754
8	Com Time-of-Day Primary (CTODP)	96,828	7,323,825	6	16,138,000	0.0756
9	Retail Transmission Service (RTS)	101,082	7,648,767	6	16,847,000	0.0757
10	Lighting Service (LS)	17,513	3,164,410	1,114	15,721	0.1807
11	Restricted Lighting Service (RLS)	16,762	3,588,537	814	20,592	0.2141
12	Lighting Energy Service (LE)	1,308	91,463	114	11,474	0.0699
13	Traffic Energy Service (TE)	974	90,011	888	1,097	0.0924
14	Special Contracts	203,003	12,687,995	3	67,667,667	0.0625
15	Com Time-of-Day Secondary	24,820	2,146,617	10	2,482,000	0.0865
16	Time-of-Day Primary (TODP)	188,359	13,088,415	10	18,835,900	0.0695
17	Time-of-Day Secondary (TODS)	32,402	2,760,102	13	2,492,462	0.0852
18	Duplicate Customers			-1,573		
19						
20	Reclassifications and Adjustments		-10,220			
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Subtotal	1,148,828	98,769,255	4,123	278,639	0.0860
39	Unbilled	-3,980	446,783			-0.1123
40	Total	1,144,848	99,216,038	4,123	277,674	0.0867
41	TOTAL Billed	11,819,090	1,077,009,557	401,371	29,447	0.0911
42	Total Unbilled Rev.(See Instr. 6)	-52,061	-243,092	0	0	0.0047
43	TOTAL	11,767,029	1,076,766,465	401,371	29,317	0.0915

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $2,140,010
Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $226
Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of ($81)
Schedule Page: 304 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $1,339
Schedule Page: 304 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $1,191
Schedule Page: 304 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $291
Schedule Page: 304 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of ($94)
Schedule Page: 304 Line No.: 9 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.
Schedule Page: 304 Line No.: 11 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.
Schedule Page: 304.1 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $73
Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $674,388
Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $1,021,078
Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $190,012
Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $961,941
Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $135,787
Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $519,510
Schedule Page: 304.1 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $614,472
Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $15,919
Schedule Page: 304.1 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $6,984
Schedule Page: 304.1 Line No.: 12 Column: c
Includes Fuel Adjustment Clause of $1
Schedule Page: 304.1 Line No.: 13 Column: c
Includes Fuel Adjustment Clause of ($215,708)
Schedule Page: 304.1 Line No.: 14 Column: c
Includes Fuel Adjustment Clause of ($190,125)
Schedule Page: 304.1 Line No.: 15 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.
Schedule Page: 304.1 Line No.: 17 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.
Schedule Page: 304.2 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $109
Schedule Page: 304.2 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $3,872

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 304.2 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $3,128

Schedule Page: 304.2 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $910

Schedule Page: 304.2 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $1,162

Schedule Page: 304.2 Line No.: 7 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304.3 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $612

Schedule Page: 304.3 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $1

Schedule Page: 304.3 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $59,203

Schedule Page: 304.3 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $173,159

Schedule Page: 304.3 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $8,578

Schedule Page: 304.3 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $74,605

Schedule Page: 304.3 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $124,772

Schedule Page: 304.3 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $56,361

Schedule Page: 304.3 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $8,036

Schedule Page: 304.3 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $7,985

Schedule Page: 304.3 Line No.: 12 Column: c
Includes Fuel Adjustment Clause of $632

Schedule Page: 304.3 Line No.: 13 Column: c
Includes Fuel Adjustment Clause of $561

Schedule Page: 304.3 Line No.: 14 Column: c
Includes Fuel Adjustment Clause of $122,566

Schedule Page: 304.3 Line No.: 15 Column: c
Includes Fuel Adjustment Clause of $37,721

Schedule Page: 304.3 Line No.: 16 Column: c
Includes Fuel Adjustment Clause of ($2,454)

Schedule Page: 304.3 Line No.: 17 Column: c
Includes Fuel Adjustment Clause of ($12,586)

Schedule Page: 304.3 Line No.: 18 Column: a
The total consists of a true-up of prior periods.

Schedule Page: 304.3 Line No.: 20 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	American Electric Power Service Corp.	OS	(3)	N/A	N/A	N/A
2	Associated Electric Coop Inc.	OS	(3)	N/A	N/A	N/A
3	Benham Power Board	OS	(6)	N/A	N/A	N/A
4	Bluegrass Generation Company,LLC	OS	(8)	N/A	N/A	N/A
5	Brookfield Energy Marketing LP	OS	(3)	N/A	N/A	N/A
6	Cargill Power Markets, LLC	OS	(3)	N/A	N/A	N/A
7	ETC Endure Energy, LLC	OS	(3)	N/A	N/A	N/A
8	Exelon Generation Company, LLC	OS	(3)	N/A	N/A	N/A
9	Illinois Municipal Electric Agency	OS	(5)	N/A	N/A	N/A
10	Illinois Municipal Electric Agency	OS	(3)	N/A	N/A	N/A
11	Illinois Municipal Electric Agency	AD	(3)	N/A	N/A	N/A
12	Indiana Municipal Power Agency	OS	(7)	N/A	N/A	N/A
13	Indiana Municipal Power Agency	OS	(3)	N/A	N/A	N/A
14	Indiana Municipal Power Agency	AD	(3)	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,340		255,582		255,582	1
333		13,002		13,002	2
4		78		78	3
66		4,066		4,066	4
344		19,184		19,184	5
19,535		973,096		973,096	6
2,385		139,035		139,035	7
773		33,562		33,562	8
512		21,574		21,574	9
2,114		91,421		91,421	10
			-3,600	-3,600	11
1,858		67,333		67,333	12
1,758		138,353		138,353	13
			-6,700	-6,700	14
0	0	0	0	0	
1,735,184	0	51,211,742	-9,953	51,201,789	
1,735,184	**0**	**51,211,742**	**-9,953**	**51,201,789**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Kentucky Municipal Power Agency	OS	(6)	N/A	N/A	N/A
2	Kentucky Utilities Company	SF	(1)	N/A	N/A	N/A
3	Midcontinent Independent System Oper	OS	(3)	N/A	N/A	N/A
4	Midcontinent Independent System Oper	AD	(3)	N/A	N/A	N/A
5	Owensboro Municipal Utilities	OS	(6)	N/A	N/A	N/A
6	Owensboro Municipal Utilities	OS	(2)	N/A	N/A	N/A
7	PJM Settlement, Inc.	OS	(3)	N/A	N/A	N/A
8	Tenaska Power Services Company	OS	(3)	N/A	N/A	N/A
9	Tennessee Valley Authority	OS	(3)	N/A	N/A	N/A
10	The Energy Authority, Inc.	OS	(3)	N/A	N/A	N/A
11	Westar Energy, Inc.	OS	(3)	N/A	N/A	N/A
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
618		24,273		24,273	1
1,481,943		36,859,944		36,859,944	2
56,032		2,910,386		2,910,386	3
			347	347	4
240		9,038		9,038	5
3,084		118,593		118,593	6
134,936		8,263,762		8,263,762	7
1,866		83,596		83,596	8
7,811		310,539		310,539	9
8,233		681,988		681,988	10
4,399		193,337		193,337	11
					12
					13
					14
0	0	0	0	0	
1,735,184	0	51,211,742	-9,953	51,201,789	
1,735,184	**0**	**51,211,742**	**-9,953**	**51,201,789**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 1 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 2 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 2 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 3 Column: b
Energy Imbalance
Schedule Page: 310 Line No.: 3 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 310 Line No.: 4 Column: b
Energy Imbalance
Schedule Page: 310 Line No.: 4 Column: c
(8) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255
Schedule Page: 310 Line No.: 5 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 5 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 6 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 6 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 7 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 7 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 8 Column: b
Market Based Sale
Schedule Page: 310 Line No.: 8 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 9 Column: b
Cost Based Sale
Schedule Page: 310 Line No.: 9 Column: c
(5) LGE CBR Tariff First Revised Service Agreement No. 3
Schedule Page: 310 Line No.: 10 Column: b
Energy Imbalance
Schedule Page: 310 Line No.: 10 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 11 Column: b
December 2014 correction made in 2015.
Schedule Page: 310 Line No.: 11 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 11 Column: j
December 2014 correction made in 2015.
Schedule Page: 310 Line No.: 12 Column: b
Cost Based Sale
Schedule Page: 310 Line No.: 12 Column: c
(7) LGE CBR Tariff Service Agreement No. 4
Schedule Page: 310 Line No.: 13 Column: b
Energy Imbalance
Schedule Page: 310 Line No.: 13 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 14 Column: b
December 2014 correction made in 2015.
Schedule Page: 310 Line No.: 14 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310 Line No.: 14 Column: j
December 2014 correction made in 2015.
Schedule Page: 310.1 Line No.: 1 Column: b
Energy Imbalance
Schedule Page: 310.1 Line No.: 1 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 310.1 Line No.: 2 Column: a
LG&E and KU are owned by PPL.
Schedule Page: 310.1 Line No.: 2 Column: c
(1) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000
Schedule Page: 310.1 Line No.: 3 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 3 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310.1 Line No.: 4 Column: b
December 2014 correction made in 2015.
Schedule Page: 310.1 Line No.: 4 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310.1 Line No.: 4 Column: j
December 2014 correction made in 2015.
Schedule Page: 310.1 Line No.: 5 Column: b
Energy Imbalance
Schedule Page: 310.1 Line No.: 5 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 310.1 Line No.: 6 Column: b
Cost Based Sale
Schedule Page: 310.1 Line No.: 6 Column: c
(2) LGE CBR Tariff and pro forma Service Agreement
Schedule Page: 310.1 Line No.: 7 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 7 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310.1 Line No.: 8 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 8 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310.1 Line No.: 9 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 9 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310.1 Line No.: 10 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 10 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff
Schedule Page: 310.1 Line No.: 11 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 11 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	7,778,894	4,111,669
5	(501) Fuel	293,363,305	375,211,977
6	(502) Steam Expenses	24,037,462	35,380,222
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.	5,774	
9	(505) Electric Expenses	1,656,803	812,391
10	(506) Miscellaneous Steam Power Expenses	16,389,656	19,494,262
11	(507) Rents	41,154	46,200
12	(509) Allowances	4,471	301,609
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	343,265,971	435,358,330
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,346,838	2,157,291
16	(511) Maintenance of Structures	2,753,377	2,770,754
17	(512) Maintenance of Boiler Plant	38,558,839	40,957,440
18	(513) Maintenance of Electric Plant	5,973,295	9,454,232
19	(514) Maintenance of Miscellaneous Steam Plant	9,599,669	1,762,911
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	60,232,018	57,102,628
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	403,497,989	492,460,958
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	124,513	128,162
45	(536) Water for Power	39,039	39,019
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	267,947	273,236
48	(539) Miscellaneous Hydraulic Power Generation Expenses	199,153	157,807
49	(540) Rents	477,265	430,474
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,107,917	1,028,698
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures	317,142	407,273
55	(543) Maintenance of Reservoirs, Dams, and Waterways	200,701	123,800
56	(544) Maintenance of Electric Plant	337,879	357,056
57	(545) Maintenance of Miscellaneous Hydraulic Plant	35,117	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	890,839	888,129
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,998,756	1,916,827

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	187,899	57,904
63	(547) Fuel	46,198,399	40,325,598
64	(548) Generation Expenses	182,717	183,061
65	(549) Miscellaneous Other Power Generation Expenses	811,542	63,538
66	(550) Rents	21,165	14,381
67	TOTAL Operation (Enter Total of lines 62 thru 66)	47,401,722	40,644,482
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	33,920	19,742
70	(552) Maintenance of Structures	110,714	82,675
71	(553) Maintenance of Generating and Electric Plant	1,410,206	1,292,339
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	682,039	104,575
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,236,879	1,499,331
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	49,638,601	42,143,813
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	59,903,876	47,842,269
77	(556) System Control and Load Dispatching	1,266,897	1,388,439
78	(557) Other Expenses	724,813	1,490,929
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	61,895,586	50,721,637
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	517,030,932	587,243,235
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	947,956	915,783
84			
85	(561.1) Load Dispatch-Reliability	265,644	1,527,812
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,048,600	136,366
87	(561.3) Load Dispatch-Transmission Service and Scheduling	365,206	76,880
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	460,299	454,898
90	(561.6) Transmission Service Studies	-936	4,515
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,574,738	1,632,632
94	(563) Overhead Lines Expenses	287,353	260,852
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	792,961	1,122,847
97	(566) Miscellaneous Transmission Expenses	5,887,745	5,529,819
98	(567) Rents	19,330	53,891
99	TOTAL Operation (Enter Total of lines 83 thru 98)	11,648,896	11,716,295
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,639,818	1,782,405
108	(571) Maintenance of Overhead Lines	932,134	999,313
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	266,398	123,305
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,838,350	2,905,023
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	14,487,246	14,621,318

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	-272,709	-286,591
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	-272,709	-286,591
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	-272,709	-286,591
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,580,294	1,936,840
135	(581) Load Dispatching	745,703	779,844
136	(582) Station Expenses	1,534,124	1,319,675
137	(583) Overhead Line Expenses	5,512,561	6,671,394
138	(584) Underground Line Expenses	683,338	391,082
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	6,397,771	6,424,055
141	(587) Customer Installations Expenses	-183,127	-125,549
142	(588) Miscellaneous Expenses	4,034,065	3,464,167
143	(589) Rents	20,070	9,916
144	TOTAL Operation (Enter Total of lines 134 thru 143)	20,324,799	20,871,424
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	70,302	168,619
147	(591) Maintenance of Structures	2,286	-2,401
148	(592) Maintenance of Station Equipment	1,084,361	895,074
149	(593) Maintenance of Overhead Lines	23,934,983	24,896,772
150	(594) Maintenance of Underground Lines	1,212,304	1,717,452
151	(595) Maintenance of Line Transformers	199,399	157,309
152	(596) Maintenance of Street Lighting and Signal Systems	403,750	308,874
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	752,563	1,228,435
155	TOTAL Maintenance (Total of lines 146 thru 154)	27,659,948	29,370,134
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	47,984,747	50,241,558
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,215,815	1,083,275
160	(902) Meter Reading Expenses	2,392,784	2,378,891
161	(903) Customer Records and Collection Expenses	5,886,201	5,552,011
162	(904) Uncollectible Accounts	2,164,601	3,877,005
163	(905) Miscellaneous Customer Accounts Expenses	-699	25,257
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	11,658,702	12,916,439

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	184,030	210,291
168	(908) Customer Assistance Expenses	13,109,791	14,158,914
169	(909) Informational and Instructional Expenses	613,839	349,853
170	(910) Miscellaneous Customer Service and Informational Expenses	398,592	422,446
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,306,252	15,141,504
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	609,852	47,452
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	609,852	47,452
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	25,503,188	24,169,655
182	(921) Office Supplies and Expenses	5,394,912	5,701,210
183	(Less) (922) Administrative Expenses Transferred-Credit	4,172,708	3,751,481
184	(923) Outside Services Employed	16,031,799	15,788,827
185	(924) Property Insurance	4,176,647	4,533,816
186	(925) Injuries and Damages	2,954,173	3,191,890
187	(926) Employee Pensions and Benefits	28,705,232	26,025,764
188	(927) Franchise Requirements	32,327	37,189
189	(928) Regulatory Commission Expenses	1,057,578	795,332
190	(929) (Less) Duplicate Charges-Cr.	265,253	286,053
191	(930.1) General Advertising Expenses	116,028	791,221
192	(930.2) Miscellaneous General Expenses	2,819,721	2,851,252
193	(931) Rents	1,150,194	1,501,129
194	TOTAL Operation (Enter Total of lines 181 thru 193)	83,503,838	81,349,751
195	Maintenance		
196	(935) Maintenance of General Plant	746,596	892,334
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	84,250,434	82,242,085
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	690,055,456	762,167,000

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Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 121 Column: b

The credit balance is the result of the monthly amortization of the net Regulatory Liability for the MISO Exit Fee. During the 2012 KY base rate case, the Company netted the MISO Exit Fee Regulatory Asset and Regulatory Liability together for a net Regulatory Liability as of January 1, 2013.

Schedule Page: 320 Line No.: 121 Column: c

The credit balance is the result of the monthly amortization of the net Regulatory Liability for the MISO Exit Fee. During the 2012 KY base rate case, the Company netted the MISO Exit Fee Regulatory Asset and Regulatory Liability together for a net Regulatory Liability as of January 1, 2013.

Schedule Page: 320 Line No.: 141 Column: b

The credit is due to meter tampering charges billed to customers to offset cost of meter maintenance. The cost is recorded in several other accounts.

Schedule Page: 320 Line No.: 141 Column: c

The credit is due to meter tampering charges billed to customers to offset cost of meter maintenance. The cost is recorded in several other accounts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Benham Power Board	OS	(3)	N/A	N/A	N/A
2	Bluegrass Generation Company, LLC	IU	(9)	N/A	N/A	N/A
3	Bluegrass Generation Company, LLC	OS	(7)	N/A	N/A	N/A
4	City of Paris	OS	(5)	N/A	N/A	N/A
5	City of Paris	AD	(5)	N/A	N/A	N/A
6	East Kentucky Power Cooperative, Inc.	OS	(11)	N/A	N/A	N/A
7	East Kentucky Power Cooperative, Inc.	OS	(3)	N/A	N/A	N/A
8	East Kentucky Power Cooperative, Inc.	IU	(9)	N/A	N/A	N/A
9	Illinois Municipal Electric Agency	EX	(8)	N/A	N/A	N/A
10	Illinois Municipal Electric Agency	AD	(8)	N/A	N/A	N/A
11	Indiana Municipal Power Agency	EX	(8)	N/A	N/A	N/A
12	Indiana Municipal Power Agency	AD	(8)	N/A	N/A	N/A
13	Kentucky Municipal Power Agency	OS	(3)	N/A	N/A	N/A
14	Kentucky Utilities Company	SF	(2)	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
13				444		444	1
69,410			5,115,626			5,115,626	2
52				1,395		1,395	3
8				160		160	4
-1					-17	-17	5
7				245		245	6
20				603		603	7
5,572			1,628,301			1,628,301	8
1,675				6,769		6,769	9
					-23	-23	10
1,165				9,803		9,803	11
					-23	-23	12
2,200				78,357		78,357	13
775,699				19,648,847		19,648,847	14
1,393,678		381,311	24,640,833	35,035,238	227,805	59,903,876	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ohio Valley Electric Corporation	OS	(6)	N/A	N/A	N/A
2	Ohio Valley Electric Corporation	AD	(6)	N/A	N/A	N/A
3	Owensboro Municipal Utilities	OS	(3)	N/A	N/A	N/A
4	PJM Interconnection LLC	OS	(1)	N/A	N/A	N/A
5	Tennessee Valley Authority	OS	(10)	N/A	N/A	N/A
6	Tennessee Valley Authority	OS	(4)	N/A	N/A	N/A
7	Inadvertent Interchange			N/A	N/A	N/A
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
527,071			17,896,906	14,992,743		32,889,649	1
					227,868	227,868	2
1,497				45,065		45,065	3
1,201				24,195		24,195	4
7,489				156,872		156,872	5
600				69,740		69,740	6
		381,311					7
							8
							9
							10
							11
							12
							13
							14
1,393,678		381,311	24,640,833	35,035,238	227,805	59,903,876	

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 1 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 326 Line No.: 2 Column: b
Tolling Agreement
Schedule Page: 326 Line No.: 2 Column: c
(9) FERC-approved tariff on file with the Commission
Schedule Page: 326 Line No.: 3 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 3 Column: c
(7) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255
Schedule Page: 326 Line No.: 4 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 4 Column: c
(5) FERC-approved tariff and or rate schedule on file with the Commission
Schedule Page: 326 Line No.: 5 Column: b
December 2014 correction made in 2015.
Schedule Page: 326 Line No.: 5 Column: c
(5) FERC-approved tariff and or rate schedule on file with the Commission
Schedule Page: 326 Line No.: 5 Column: l
December 2014 correction made in 2015.
Schedule Page: 326 Line No.: 6 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 6 Column: c
(11) FERC-approved tariff and/or rate schedule on file with the Commission. EEI Master Power Purchase and Sale Agreement dated November 20, 2009.
Schedule Page: 326 Line No.: 7 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 7 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 326 Line No.: 8 Column: b
Tolling Agreement
Schedule Page: 326 Line No.: 8 Column: c
(9) FERC-approved tariff on file with the Commission
Schedule Page: 326 Line No.: 9 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 9 Column: c
(8) FERC-approved tariff and/or rate schedule as on file with the Commission. Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 10 Column: b
December 2014 correction made in 2015.
Schedule Page: 326 Line No.: 10 Column: c
(8) FERC-approved tariff and/or rate schedule as on file with the Commission. Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 10 Column: l
December 2014 correction made in 2015.
Schedule Page: 326 Line No.: 11 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 11 Column: c
(8) FERC-approved tariff and/or rate schedule as on file with the Commission. Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 12 Column: b
December 2014 correction made in 2015.

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 12 Column: c
(8) FERC-approved tariff and/or rate schedule as on file with the Commission. Participation Agreement dated February 9, 2004.

Schedule Page: 326 Line No.: 12 Column: l
December 2014 correction made in 2015.

Schedule Page: 326 Line No.: 13 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 13 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326 Line No.: 14 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 326 Line No.: 14 Column: c
(2) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000

Schedule Page: 326.1 Line No.: 1 Column: a
Intercompany Power Agreement dated September 10, 2010. The Company owns 5.63% of the common stock of OVEC. Purchase of surplus power pursuant to Article 4 of the Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 1 Column: b
Surplus Power

Schedule Page: 326.1 Line No.: 1 Column: c
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 2 Column: a
Intercompany Power Agreement dated September 10, 2010. The Company owns 5.63% of the common stock of OVEC. Purchase of surplus power pursuant to Article 4 of the Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 2 Column: b
December 2014 true-up of accrual estimate for both energy and demand charges booked in 2015.

Schedule Page: 326.1 Line No.: 2 Column: c
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 2 Column: l
December 2014 true-up of accrual estimate for both energy and demand charges booked in 2015.

Schedule Page: 326.1 Line No.: 3 Column: b
Energy Imbalance

Schedule Page: 326.1 Line No.: 3 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326.1 Line No.: 4 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 4 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission

Schedule Page: 326.1 Line No.: 5 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 5 Column: c
(10) FERC Electric Rate Schedule No. 28 Interchange Agreement dated July 1, 1977

Schedule Page: 326.1 Line No.: 6 Column: b
Emergency Power

Schedule Page: 326.1 Line No.: 6 Column: c
(4) FERC-approved tariff and/or rate schedule as on file with the Commission as stated in

BLANK

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

the Contingency Reserve Sharing Agreement dated November 20, 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF
4	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
5	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
6	Indiana Municipal Power Agency	Indiana Municipal Power Agency	Midwest ISO and PJM	OLF
7	Indiana Municipal Power Agency	Indiana Municipal Power Agency	Midwest ISO and PJM	LFP
8	Illinois Municipal Electric Agency	IL Municipal Electric Agency	Midwest ISO	OLF
9	Illinois Municipal Electric Agency	IL Municipal Electric Agency	Midwest ISO	LFP
10	Cargill Power Markets, LLC	Various	Various	AD
11	LG&E/KU	Various	Various	NF
12	LG&E/KU	Various	Various	AD
13	LG&E/KU	Various	Various	SFP
14	LG&E/KU	Various	Various	LFP
15	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO
16	Hoosier Energy	Midwest ISO	Hoosier Energy	AD
17	Hoosier Energy	Midwest ISO	Hoosier Energy	AD
18	Kentucky Municipal Power Agency	Midwest ISO	LG&E	FNO
19	Kentucky Municipal Power Agency	Midwest ISO	LG&E	AD
20	Kentucky Municipal Power Agency	Midwest ISO	LG&E	AD
21	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO
22	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
23	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
24	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP
25	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
26	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF
27	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
28	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO
29	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	AD
30	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	AD
31	City of Benham	Midwest ISO	City of Benham	FNO
32	City of Benham	Midwest ISO	City of Benham	OS
33	City of Benham	Midwest ISO	City of Benham	AD
34	The Energy Authority	Various	Various	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
LGE/KU Joint	East Kentucky Power	East Kentucky Power	61	343,207	343,207	1
LGE/KU Joint	East Kentucky Power	East Kentucky Power				2
LGE/KU Joint	East Kentucky Power	East Kentucky Power				3
LGE/KU Joint	East Kentucky Power	East Kentucky Power				4
LGE/KU Joint	East Kentucky Power	East Kentucky Power				5
LGE/KU Joint	Trimble Co. Unit 1	Midwest ISO and PJM		425,380	425,380	6
LGE/KU Joint	Trimble Co. Unit 2	Midwest ISO and PJM		703,333	703,333	7
LGE/KU Joint	Trimble Co. Unit 1	Midwest ISO		370,005	370,005	8
LGE/KU Joint	Trimble Co. Unit 2	Midwest ISO		661,596	661,596	9
LGE/KU Joint	Various	Various				10
LGE/KU Joint	Various	Various				11
LGE/KU Joint	Various	Various				12
LGE/KU Joint	Various	Various	21			13
LGE/KU Joint	Various	Various	8			14
LGE/KU Joint	Midwest ISO	Hoosier Energy	2	10,843	10,843	15
LGE/KU Joint	Midwest ISO	Hoosier Energy				16
LGE/KU Joint	Miswest ISO	Hoosier Energy				17
SA 13	Various	LGEE.KMPA	36	217,898	217,898	18
SA 13	Various	LGEE.KMPA				19
SA 13	Various	LGEE.KMPA				20
SA 15	Owensboro Municipal	Various	40	1,855	1,855	21
SA 15	Owensboro Municipal	Various				22
SA 15	Owensboro Municipal	Various				23
LGE/KU Joint	Owensboro Municipal	Various	81	462,853	462,853	24
LGE/KU Joint	Owensboro Municipal	Various				25
LGE/KU Joint	Owensboro Municipal	Various				26
LGE/KU Joint	Owensboro Municipal	Various				27
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric	3	23,331	23,331	28
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric				29
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric				30
LGE/KU Joint	Midwest ISO	City of Benham		1,004	1,004	31
LGE/KU Joint	Midwest ISO	City of Benham				32
LGE/KU Joint	Midwest ISO	City of Benham				33
LGE/KU Joint	Various	Various	2	2,096	2,096	34
			1,438	**3,330,769**	**3,330,769**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	The Energy Authority	Various	Various	NF
2	The Energy Authority	Various	Various	AD
3	The Energy Authority	Various	Various	AD
4	Constellation Energy Commodities Group	PJM	TVA	AD
5	Dynegy Energy	Various	Various	SFP
6	Dynegy Energy	Various	Various	AD
7	EDF Trading	Various	Various	NF
8	EDF Trading	Various	Various	AD
9	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	FNO
10	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
11	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
12	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
13	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF
14	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
15	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
16	Midwest ISO	Midwest ISO	Midwest ISO	AD
17	City of Barbourville	Various	City of Barbourville	FNO
18	City of Barbourville	Various	City of Barbourville	AD
19	City of Bardstown	Various	City of Bardstown	FNO
20	City of Bardstown	Various	City of Bardstown	AD
21	City of Bardwell	Various	City of Bardwell	FNO
22	City of Bardwell	Various	City of Bardwell	AD
23	City of Benham	Various	City of Benham	FNO
24	City of Benham	Various	City of Benham	AD
25	City of Berea	Various	City of Berea	FNO
26	City of Berea	Various	City of Berea	AD
27	City of Corbin	Various	City of Corbin	FNO
28	City of Corbin	Various	City of Corbin	AD
29	City of Falmouth	Various	City of Falmouth	FNO
30	City of Falmouth	Various	City of Falmouth	AD
31	City of Frankfort	Various	City of Frankfort	FNO
32	City of Frankfort	Various	City of Frankfort	AD
33	City of Madisonville	Various	City of Madisonville	FNO
34	City of Madisonville	Various	City of Madisonville	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
LGE/KU Joint	Various	Various		90	90	1
LGE/KU Joint	Various	Various				2
LGE/KU Joint	Various	Various				3
LGE/KU Joint	PJM	TVA				4
LGE/KU Joint	Various	Various				5
LGE/KU Joint	Various	Various				6
LGE/KU Joint	Various	Various		886	886	7
LGE/KU Joint	Various	Various				8
LGE/KU Joint	TVA	TVA	20	106,392	106,392	9
LGE/KU Joint	TVA	TVA				10
LGE/KU Joint	TVA	TVA				11
LGE/KU Joint	TVA	TVA				12
LGE/KU Joint	TVA	TVA				13
LGE/KU Joint	TVA	TVA				14
LGE/KU Joint	TVA	TVA				15
N/A	Midwest ISO	N/A				16
184	Various	City of Barbourville	64			17
184	Various	City of Barbourville				18
185	Various	City of Bardstown	122			19
185	Various	City of Bardstown				20
186	Various	City of Bardwell	6			21
186	Various	City of Bardwell				22
187	Various	City of Benham	3			23
187	Various	City of Benham				24
197	Various	City of Berea	89			25
197	Various	City of Berea				26
188	Various	City of Corbin	57			27
188	Various	City of Corbin				28
189	Various	City of Falmouth	12			29
189	Various	City of Falmouth				30
190	Various	City of Frankfort	448			31
190	Various	City of Frankfort				32
161	Various	City of Madisonville	163			33
161	Various	City of Madisonville	12			34
			1,438	**3,330,769**	**3,330,769**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	City of Nicholasville	Various	City of Nicholasville	FNO
2	City of Nicholasville	Various	City of Nicholasville	AD
3	City of Paris	Various	City of Paris	FNO
4	City of Paris	Various	City of Paris	AD
5	City of Providence	Various	City of Providence	FNO
6	City of Providence	Various	City of Providence	AD
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
157	Various	City of Nicholasvile	126			1
157	Various	City of Nicholasvile				2
83	Various	City of Paris	43			3
83	Various	City of Paris				4
195	Various	City of Providence	19			5
195	Various	City of Providence				6
						7
						8
						9
						10
						11
						12
						13
						14
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						18
						19
						20
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						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,438	**3,330,769**	**3,330,769**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,940,986		188,229	2,129,215	1
-12,128			-12,128	2
	2,548	231	2,779	3
-2,375	-95		-2,470	4
-6,331			-6,331	5
				6
				7
				8
				9
	-83		-83	10
	315,836	24,076	339,912	11
-1,197			-1,197	12
133,466		12,974	146,440	13
137,620		14,088	151,708	14
24,811		2,385	27,196	15
-10			-10	16
-62			-62	17
641,498		228,020	869,518	18
13,367			13,367	19
-1,754			-1,754	20
568,235		220,668	788,903	21
17,659			17,659	22
-4,027			-4,027	23
1,431,225		146,512	1,577,737	24
19,650			19,650	25
	158,393	13,725	172,118	26
	2,159		2,159	27
50,645		5,331	55,976	28
1,003	-1,599		-596	29
361			361	30
3,550		1,274	4,824	31
		762	762	32
-12			-12	33
3,538		360	3,898	34
7,095,563	**564,541**	**983,517**	**8,643,621**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	308	18	326	1
1			1	2
-4			-4	3
	555		555	4
		-227	-227	5
	17,137		17,137	6
	3,244	190	3,434	7
	32		32	8
373,760		36,139	409,899	9
-2,021			-2,021	10
-794			-794	11
1,365			1,365	12
	7		7	13
	3		3	14
	-116		-116	15
	66,212		66,212	16
95,286		4,833	100,119	17
467			467	18
183,203		9,215	192,418	19
1,057			1,057	20
8,528		424	8,952	21
-110			-110	22
3,971		234	4,205	23
43			43	24
132,259		6,767	139,026	25
508			508	26
84,571		4,268	88,839	27
501			501	28
18,685		937	19,622	29
77			77	30
667,755		33,778	701,533	31
3,338			3,338	32
262,077		14,061	276,138	33
18,617			18,617	34
7,095,563	**564,541**	**983,517**	**8,643,621**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
188,143		9,551	197,694	1
1,131			1,131	2
64,550		3,292	67,842	3
570			570	4
28,025		1,402	29,427	5
286			286	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,095,563	**564,541**	**983,517**	**8,643,621**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 2 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 3 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 4 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 4 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 5 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 6 Column: a
LG&E transmits electricity for IMPA from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 6 Column: d
The OLF transmission service agreement between LG&E and IMPA has no expiration date.

Schedule Page: 328 Line No.: 7 Column: a
LG&E transmits electricity for IMPA from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 7 Column: d
The LFP transmission service agreement between LG&E and IMPA has a termination date of 1/01/2020 for Trimble County Unit 2.

Schedule Page: 328 Line No.: 8 Column: a
LG&E transmits electricity for IMEA from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 8 Column: d
The OLF transmission service agreement between LG&E and IMEA has a termination date of 3/1/2023 for Trimble County Unit 1.

Schedule Page: 328 Line No.: 9 Column: a
LG&E transmits electricity for IMEA from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 9 Column: d
The LFP transmission service agreement between LG&E and IMEA has a termination date of 1/1/2020 for Trimble County Unit 2.

Schedule Page: 328 Line No.: 10 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 11 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 11 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 12 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 12 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 13 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 13 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 14 Column: a

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 14 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 15 Column: m
The total consists of Hoosier Energy Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 16 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 17 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 18 Column: m
The total consists of Kentucky Municipal Power Agency Schedule 1, Schedule 2, Schedule 3, Schedule 5 and Schedule 6 charges.

Schedule Page: 328 Line No.: 19 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 20 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 21 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1, Schedule 2, Schedule 3, Schedule 5 and Schedule 6 charges.

Schedule Page: 328 Line No.: 22 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 23 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 24 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 25 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 26 Column: m
Includes Fuel Adjustment Clause of $1

Schedule Page: 328 Line No.: 27 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 28 Column: m
The total consists of Big Rivers Electric Corporation Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 29 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 29 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 30 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 31 Column: m
The total consists of City of Benham Schedule 1, Schedule 2, Schedule 3, Schedule 5 and Schedule 6 charges.

Schedule Page: 328 Line No.: 32 Column: m
The total consists of City of Benham Direct Facility Assignment Charges.

Schedule Page: 328 Line No.: 33 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 34 Column: m
The total consists of The Energy Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 1 Column: m
The total consists of The Energy Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 2 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 3 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328.1 Line No.: 4 Column: l

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 5 Column: m
The total consists of Dynegy Energy Schedule 2 charges.

Schedule Page: 328.1 Line No.: 6 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 7 Column: m
The total consists of EDF Trading Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 8 Column: l
The total consists of a true-up of prior periods.

Schedule Page: 328.1 Line No.: 9 Column: j
This footnote is not to reference this cell, but the total on Line No.: 35, Column: j.
All Inadvertent Interchange is reported on Page 327.1, Line No.: 7, Column: i.

Schedule Page: 328.1 Line No.: 9 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 10 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328.1 Line No.: 11 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328.1 Line No.: 12 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 14 Column: l
The total consists of a true-up of prior periods.

Schedule Page: 328.1 Line No.: 15 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 16 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 17 Column: m
The total consists of City of Barbourville Schedule 1 charges.

Schedule Page: 328.1 Line No.: 18 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 19 Column: m
The total consists of City of Bardstown Schedule 1 charges.

Schedule Page: 328.1 Line No.: 20 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 21 Column: m
The total consists of City of Bardwell Schedule 1 charges.

Schedule Page: 328.1 Line No.: 22 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 23 Column: m
The total consists of City of Benham Schedule 1 charges.

Schedule Page: 328.1 Line No.: 24 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 25 Column: m
The total consists of City of Berea Schedule 1 charges.

Schedule Page: 328.1 Line No.: 26 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 27 Column: m
The total consists of City of Corbin Schedule 1 charges.

Schedule Page: 328.1 Line No.: 28 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 29 Column: m
The total consists of City of Falmouth Schedule 1 charges.

Schedule Page: 328.1 Line No.: 30 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 31 Column: m

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

The total consists of City of Frankfort Schedule 1 charges.

Schedule Page: 328.1 Line No.: 32 Column: k

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.1 Line No.: 33 Column: m

The total consists of City of Madisonville Schedule 1 charges.

Schedule Page: 328.1 Line No.: 34 Column: k

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.2 Line No.: 1 Column: m

The total consists of City of Nicholasville Schedule 1 charges.

Schedule Page: 328.2 Line No.: 2 Column: k

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.2 Line No.: 3 Column: m

The total consists of City of Paris Schedule 1 charges.

Schedule Page: 328.2 Line No.: 4 Column: k

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.2 Line No.: 5 Column: m

The total consists of City of Providence Schedule 1 charges.

Schedule Page: 328.2 Line No.: 6 Column: k

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.2 Line No.: 6 Column: n

This footnote is not to reference this cell, but the total on Line No.: 35, Column: n.

Reconciliation of revenues from transmission of electricity of others to amount reported in electric operating revenues:

Schedule Page: 330.1, Line No.: 35, Column: n	$ 8,643,621
Elimination of intracompany transmission revenues	(256,081)
Schedule Page: 300, Line No.: 22, Column: b	$ 8,387,540

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Energy Charges ($) (f)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Other Charges ($) (g)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Total Cost of Transmission ($) (h)
1	LG&E/KU	LFP	58,811	58,811	38,242		4,075	42,317
2	LG&E/KU	SFP	1,809,916	1,809,916	141,352		15,901	157,253
3	LG&E/KU	NF	122,385	122,385		573,957	45,839	619,796
4	PJM Interconnect	SFP	67,913	67,913	205,318			205,318
5	PJM Interconnect	NF	2,511	2,511		1,748	20,596	22,344
6	PJM Interconnect	AD				-647	2,661	2,014
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,061,536	2,061,536	384,912	575,058	89,072	1,049,042

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 332 Line No.: 1 Column: b
Long-Term Firm purchases by LG&E and KU take place under the Open Access Transmission Tariff (OATT) with intercompany allocations for revenues and expenses determined by the Transmission Coordination Agreement between the Companies. The Tariff is evergreen and the Transmission Coordination Agreement automatically renews unless terminated.

Schedule Page: 332 Line No.: 1 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 2 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 332 Line No.: 2 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 3 Column: a
LG&E and KU are owned by PPL.

Schedule Page: 332 Line No.: 3 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 5 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 6 Column: f
The total consists of a true-up of prior periods.

Schedule Page: 332 Line No.: 6 Column: g
The total consists of a true-up of prior periods of Schedule 1, Schedule 2 and Black Start Service charges.

Schedule Page: 332 Line No.: 6 Column: h
This footnote is not to reference this cell, but the total on Line No.: 17, Column: h.

Reconciliation of transmission of electricity by others to amount reported in transmission expenses:

Schedule Page: 332, Line No.: 17, Column: h	$ 1,049,042
Elimination of intracompany transmission expenses	(256,081)
Schedule Page: 321, Line No.: 96, Column: b	$ 792,961

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	673,439
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,568,345
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Market Research and Consulting Expenses:	
7	Bellomy Research	103,314
8	Vision Critical Communications US Inc	23,204
9	Insight Services	5,076
10	IBEW Non-Billable Charges	36,650
11	IEEE Customer Operations Subscription	5,953
12	Wellness Scheller's Fitness & Cycling	5,181
13	Swap Termination Amortization	307,079
14	Miscellaneous	91,480
15		
16		
17		
18		
19		
20		
21		
22		
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46	TOTAL	2,819,721

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant	59,620,614				59,620,614
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	2,521,865				2,521,865
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,015,064				12,015,064
7	Transmission Plant	7,018,552				7,018,552
8	Distribution Plant	31,797,816				31,797,816
9	Regional Transmission and Market Operation					
10	General Plant	856,655				856,655
11	Common Plant-Electric	8,373,267		7,464,986		15,838,253
12	TOTAL	122,203,833		7,464,986		129,668,819

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2015	AMORTIZATION	
330300	14%	$ 50,228,459	$ 4,304,705	
330310	10%	45,350,035	3,160,281	

			$ 7,464,986	Column (d)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Other Production Plant						
13	341 Strctrs & Imprvmts						
14	0172 Cane Run Unit 7	16,721	60.00		2.62	60-S1.5	38.20
15							
16	342 Fuel Holders Prdcr						
17	0172 Cane Run Unit 7	31,223	55.00	-5.00	2.73	55-R3	38.42
18							
19	343 Prime Movers						
20	0172 Cane Run Unit 7	25,159	55.00	-5.00	2.79	55-R2.5	37.68
21							
22	344 Generators						
23	0172 Cane Run Unit 7	31,742	50.00	-10.00	3.11	50-R1.5	35.35
24							
25	345 Accessry Elec Eqpm						
26	0172 Cane Run Unit 7	7,359	50.00	-5.00	2.97	50-S0.5	35.33
27							
28	0346 Misc Plant Eqpmt						
29	0172 Cane Run Unit 7	4	45.00		2.82	45-R2	35.41
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FERC				
2	Annual Charge	350,592		350,592	
3	Administrative Charge, Project #289	188,645		188,645	
4					
5	KPSC				
6	2014 Rate Case - Electric (Jul-15 to Jun-18)		189,600	189,600	753,342
7	2014 Rate Case - Gas (Jul-15 to Jun-18)		47,400	47,400	188,335
8					
9	2012 Rate Case - Electric (Jan-13 to Dec-15)		298,214	298,214	298,214
10	2012 Rate Case - Gas (Jan-13 to Dec-15)		94,960	94,960	94,960
11					
12	2011 Gen Mgmt Audit - Elec (Jan-13 to Dec-15)		30,527	30,527	30,527
13	2011 Gen Mgmt Audit - Gas (Jan-13 to Dec-15)		9,941	9,941	9,941
14					
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46	TOTAL	539,237	670,642	1,209,879	1,375,319

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	350,592					2
Electric	928	188,645					3
							4
							5
Electric	928	189,600	383,968	928	189,600	947,710	6
Gas	928	47,400	95,992	928	47,400	236,927	7
							8
Electric	928	298,214		928	298,214		9
Gas	928	94,960		928	94,960		10
							11
Electric	928	30,527		928	30,527		12
Gas	928	9,941		928	9,941		13
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		1,209,879	479,960		670,642	1,184,637	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:
A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $50,000.)
(7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	EPRI (1)	Annual Membership and Annual Research Portfolio
2	EPRI (1)	Annual Membership and Annual Research Portfolio
3	EPRI (1)	Annual Membership and Annual Research Portfolio
4	EPRI (1)	Evaluating Smart Thermostats Impact on Energy Efficiency and Demand Respos
5	EPRI (1)	Ohio River Ecological Research
6	EPRI (1)	Tailored Collaboration
7	University of Kentucky Research Foundation (4)	Amortization of Carbon Capturing Research Regulatory Asset
8	University of Texas at Austin (4)	Tailored Collaboration
9	Ronald Doades and Company (1)	Annual Participation in Research & Technology Management Forum
10	Georgia Tech Research Corporation (1)	NEETRAC Membership Renewal
11	HDR Engineering Inc (1)	Tailored Collaboration for Energy Stoage Demonstration
12	HDR Engineering Inc (1)	Tailored Collaboration for Construction Drawings and Procurement Specifics
13	HDR Engineering Inc (1)	Tailored Collaboration for Construction Drawings and Procurement Specifics
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	1,373,412	930	1,373,412		1
	182,913	107	182,913		2
	47,123	183	47,123		3
	25,000	908	25,000		4
	13,703	930	13,703		5
	4,950	921	4,950		6
	97,560	930	97,560		7
	52,500	930	52,500		8
	5,220	930	5,220		9
	18,190	930	18,190		10
	7,760	930	7,760		11
	14,019	188	14,019	14,019	12
	12,416	188	12,416	12,416	13
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			1,854,766		36
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	24,560,753		
4	Transmission	2,755,115		
5	Regional Market			
6	Distribution	8,216,253		
7	Customer Accounts	4,111,598		
8	Customer Service and Informational	744,996		
9	Sales			
10	Administrative and General	18,918,444		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	59,307,159		
12	Maintenance			
13	Production	10,527,971		
14	Transmission	501,545		
15	Regional Market			
16	Distribution	2,577,698		
17	Administrative and General	427,479		
18	TOTAL Maintenance (Total of lines 13 thru 17)	14,034,693		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	35,088,724		
21	Transmission (Enter Total of lines 4 and 14)	3,256,660		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	10,793,951		
24	Customer Accounts (Transcribe from line 7)	4,111,598		
25	Customer Service and Informational (Transcribe from line 8)	744,996		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	19,345,923		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	73,341,852	18,378,544	91,720,396
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	567,263		
34	Storage, LNG Terminaling and Processing	2,062,326		
35	Transmission	904,800		
36	Distribution	3,694,058		
37	Customer Accounts	3,364,035		
38	Customer Service and Informational	265,190		
39	Sales			
40	Administrative and General	5,231,147		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	16,088,819		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,462,982		
47	Transmission	389,102		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	5,317,173		
49	Administrative and General	183,206		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,352,463		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	567,263		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,525,308		
56	Transmission (Lines 35 and 47)	1,293,902		
57	Distribution (Lines 36 and 48)	9,011,231		
58	Customer Accounts (Line 37)	3,364,035		
59	Customer Service and Informational (Line 38)	265,190		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	5,414,353		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	23,441,282	6,157,189	29,598,471
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	96,783,134	24,535,733	121,318,867
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	12,275,422	11,737,736	24,013,158
69	Gas Plant	5,819,800	4,273,104	10,092,904
70	Other (provide details in footnote):	2,657,598	1,023,963	3,681,561
71	TOTAL Construction (Total of lines 68 thru 70)	20,752,820	17,034,803	37,787,623
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,578,768	1,179,541	2,758,309
74	Gas Plant	280,721	347,974	628,695
75	Other (provide details in footnote):		21	21
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,859,489	1,527,536	3,387,025
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable (work done for others)	11,127,366	2,941,769	14,069,135
79	Deferred Debits	77,095	20,879	97,974
80	Certain Civic, Political and Related Activities and Other	622,310	78,888	701,198
81	Accounts Receivable (Non-jurisdictional - Trimble County)	2,289,312	617,634	2,906,946
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	14,116,083	3,659,170	17,775,253
96	TOTAL SALARIES AND WAGES	133,511,526	46,757,242	180,268,768

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

(1) See attached sheet, page 356.1.

(2) See attached sheet, page 356.1.

(3) Depreciation - Electric $8,373,267; Gas $3,588,543. Amortization - Electric $7,464,986; Gas $3,199,280.

Common Utility expense accounts are not maintained but such expenses are allocated to Electric and Gas Departments as follows:

Customer Accounts Expenses (excluding for uncollectable accounts)

Allocated between departments based on average number of customers served by each department for the year ending December 31, 2014.

Customer Service and Informational Expenses

Allocated between departments based on gross revenues from ultimate consumers by departments for the twelve month period.

Administrative and General Expenses

The administrative and general expenses are allocated based on general measures of cost causation.

(4) The property original cost studies made pursuant to the Uniform System of Accounts included a separate classification for Common Utility Plant. Orders were issued in connection with such studies by Public Service Commission of Kentucky on September 16, 1941, and January 5, 1945, and the Federal Power Commission on December 15, 1944.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant (1)
Allocation to Utility Department (2)

Accounts 101 and 106	Electric 70%	Gas 30%	Balance End of Year
Intangible Plant			
301 Organization			$ 83,781
303 Miscellaneous Intangible Plant			95,578,496
Total Intangible Plant			$ 95,662,277
Common Plant			
389 Land and Land Rights			$ 1,766,489
390 Structures and Improvements			77,686,145
391 Office and Furniture and Equipment			38,573,809
392 Transportation Equipment			281,880
393 Stores Equipment			1,493,842
394 Tools, Shop and Garage Equipment			3,983,606
396 Power Operated Equipment			315,562
397 Communication Equipment			46,179,915
Total Common Plant			$ 170,281,248
Total Accounts 101 and 106			$ 265,943,525
Account 107			10,298,144
Total Common Utility Plant	$ 193,369,168	$ 82,872,501	$ 276,241,669

Accumulated Provision for Depreciation of Common Utility Plant

	Electric 70%	Gas 30%	Balance End of Year
Balance at end of year	$ 96,876,366	$ 41,518,443	$ 138,394,809

(1) Common plant consists of land, structures and equipment of a general nature used by all departments not specifically assignable to one department, and includes offices, storerooms, communication, transportation and work equipment, etc.

(2) Based on estimated usage by departments.

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)		73	4,326	24,195
3	Net Sales (Account 447)	9,634,855	10,357,635	10,773,028	11,174,495
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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46	TOTAL	9,634,855	10,357,708	10,777,354	11,198,690

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	2,061,536	MWH	33,562	1,170,455	MWH	379,298
2	Reactive Supply and Voltage	2,061,536	MWH	52,667	1,170,455	MWH	251,137
3	Regulation and Frequency Response				683,610	MWH	85,932
4	Energy Imbalance	3,782	MWH	125,864		MWH	
5	Operating Reserve - Spinning				683,610	MWH	133,194
6	Operating Reserve - Supplement				683,610	MWH	133,194
7	Other			2,843			762
8	Total (Lines 1 thru 7)	4,126,854		214,936	4,391,740		983,517

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 7 Column: b
The Other services amounts are not associated with a number of units or a unit of measure.
Schedule Page: 398 Line No.: 7 Column: d
This amount consists of Black Start services.
Schedule Page: 398 Line No.: 7 Column: e
The Other services amounts are not associated with a number of units or a unit of measure.
Schedule Page: 398 Line No.: 7 Column: g
This amount consists of City of Benham Direct Facility Assignment Charges.
Schedule Page: 398 Line No.: 8 Column: b
The number of units per ancillary service type cover multiple schedules and should not be accumulated in total.
Schedule Page: 398 Line No.: 8 Column: e
The number of units per ancillary service type cover multiple schedules and should not be accumulated in total.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	2,449	8	8	1,973	254	191		31	
2	February	2,561	20	8	1,967	262	191		141	
3	March	2,128	6	8	1,712	225	191			
4	Total for Quarter 1				5,652	741	573		172	
5	April	1,845	9	15	1,524	130	191			
6	May	2,400	11	14	2,023	186	191			
7	June	2,906	15	16	2,472	243	191			
8	Total for Quarter 2				6,019	559	573			
9	July	3,012	29	15	2,585	233	194			
10	August	2,938	3	17	2,484	260	194			
11	September	2,882	4	16	2,443	245	194			
12	Total for Quarter 3				7,512	738	582			
13	October	2,142	8	16	1,797	151	194			
14	November	2,067	23	8	1,570	208	194		95	
15	December	1,966	4	8	1,570	202	194			
16	Total for Quarter 4				4,937	561	582		95	
17	Total Year to Date/Year				24,120	2,599	2,310		267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	11,767,029
3	Steam	11,522,245			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	273,775			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,735,184
7	Other	1,258,247			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	1,525
9	Net Generation (Enter Total of lines 3 through 8)	13,054,267	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	22,438
10	Purchases	1,393,678	27	Total Energy Losses	540,458
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	14,066,634
12	Received				
13	Delivered	381,311			
14	Net Exchanges (Line 12 minus line 13)	-381,311			
15	Transmission For Other (Wheeling)				
16	Received	3,330,769			
17	Delivered	3,330,769			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	14,066,634			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,394,600	338,016	1,976	8	900
30	February	1,459,388	464,465	1,967	20	800
31	March	1,207,744	267,211	1,724	6	900
32	April	1,056,598	209,920	1,527	9	1600
33	May	1,123,735	103,509	2,043	7	1700
34	June	1,235,371	42,384	2,488	23	1600
35	July	1,302,513	26,749	2,594	29	1600
36	August	1,235,068	29,516	2,484	3	1700
37	September	1,126,324	39,647	2,443	4	1600
38	October	994,744	79,391	1,827	7	1700
39	November	960,910	96,075	1,570	23	800
40	December	969,639	38,301	1,577	18	1900
41	TOTAL	14,066,634	1,735,184			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Mill Creek* (b)			Plant Name: *Cane Run* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1972			1954		
4	Year Last Unit was Installed	1982			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1717.00			645.00		
6	Net Peak Demand on Plant - MW (60 minutes)	1483			556		
7	Plant Hours Connected to Load	7260			2414		
8	Net Continuous Plant Capability (Megawatts)	1465			563		
9	When Not Limited by Condenser Water	1465			563		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	249			63		
12	Net Generation, Exclusive of Plant Use - KWh	7935224000			736744000		
13	Cost of Plant: Land and Land Rights	1919832			1312195		
14	Structures and Improvements	144918002			17304448		
15	Equipment Costs	1602621715			17553217		
16	Asset Retirement Costs	67310143			21975097		
17	Total Cost	1816769692			58144957		
18	Cost per KW of Installed Capacity (line 17/5) Including	1058.1070			90.1472		
19	Production Expenses: Oper, Supv, & Engr	2497323			3643543		
20	Fuel	201119632			22477350		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	15303127			6164519		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	815214			21736		
26	Misc Steam (or Nuclear) Power Expenses	9038061			3496712		
27	Rents	37100			4250		
28	Allowances	286			146		
29	Maintenance Supervision and Engineering	2336085			413125		
30	Maintenance of Structures	1745293			184402		
31	Maintenance of Boiler (or reactor) Plant	26954896			2098953		
32	Maintenance of Electric Plant	3732398			405054		
33	Maintenance of Misc Steam (or Nuclear) Plant	978520			7956304		
34	Total Production Expenses	264557935			46866094		
35	Expenses per Net KWh	0.0333			0.0636		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas		Coal	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	mcf		tons	mcf	
38	Quantity (Units) of Fuel Burned	3463183	408752	0	384993	64994	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12057	1014	0	11203	1018	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	55.660	10.006	0.000	57.490	2.854	0.000
41	Average Cost of Fuel per Unit Burned	56.893	10.006	0.000	57.902	2.854	0.000
42	Average Cost of Fuel Burned per Million BTU	2.359	9.865	0.000	2.584	2.804	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	10524.000	0.000	0.000	11709.000	0.000	0.000

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Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Trimble County* (d)	Plant Name: *Cane Run CT* (e)	Plant Name: *Paddy's Run CT* (f)	Line No.
Steam	Combustion Turbine	Combustion Turbine	1
Conventional	Conventional	Conventional	2
1990	1968	1968	3
2011	1968	2001	4
544.00	16.00	143.00	5
659	12	103	6
7312	73	453	7
488	14	113	8
488	14	113	9
0	0	0	10
188	0	0	11
3904998000	256000	95560000	12
3555900	0	2957	13
129572289	211518	2478176	14
687181830	9976512	41072319	15
48452581	0	0	16
868762600	10188030	43553452	17
1596.9901	636.7519	304.5696	18
2184039	0	0	19
95725338	40829	3627066	20
0	0	0	21
3463561	0	0	22
0	0	0	23
0	0	0	24
1093138	26775	20476	25
5139847	0	0	26
-261	0	12149	27
5385	0	0	28
796840	0	8948	29
1098241	1106	3649	30
12673825	0	0	31
2447793	69590	454920	32
886461	0	0	33
125514207	138300	4127208	34
0.0321	0.5402	0.0432	35

(d)			(e)			(f)			Line No.
Coal	Oil		Gas			Gas			36
tons	barrels		mcf			mcf			37
1799920	14351	0	14146	0	0	1029359	0	0	38
11228	3333	0	1022	0	0	1012	0	0	39
50.810	57.223	0.000	2.886	0.000	0.000	3.524	0.000	0.000	40
38.203	57.223	0.000	2.886	0.000	0.000	3.524	0.000	0.000	41
1.701	9.732	0.000	2.824	0.000	0.000	3.483	0.000	0.000	42
0.018	0.000	0.000	0.159	0.000	0.000	0.038	0.000	0.000	43
10350.000	0.000	0.000	56473.000	0.000	0.000	10899.000	0.000	0.000	44

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Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Zorn CT* (b)			Plant Name: *Brown CT* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combustion Turbine			Combustion Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1969			1999		
4	Year Last Unit was Installed	1969			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	18.00			200.00		
6	Net Peak Demand on Plant - MW (60 minutes)	12			181		
7	Plant Hours Connected to Load	116			1181		
8	Net Continuous Plant Capability (Megawatts)	14			190		
9	When Not Limited by Condenser Water	14			190		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			154		
12	Net Generation, Exclusive of Plant Use - KWh	1058000			204529000		
13	Cost of Plant: Land and Land Rights	0			5015		
14	Structures and Improvements	8241			1121072		
15	Equipment Costs	1954572			71697211		
16	Asset Retirement Costs	21720			0		
17	Total Cost	1984533			72823298		
18	Cost per KW of Installed Capacity (line 17/5) Including	110.2518			364.1165		
19	Production Expenses: Oper, Supv, & Engr	0			55823		
20	Fuel	82407			6602843		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	8159			101204		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			9120		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			12681		
30	Maintenance of Structures	0			67400		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	22714			388575		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	113280			7237646		
35	Expenses per Net KWh	0.1071			0.0354		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf			mcf		
38	Quantity (Units) of Fuel Burned	21063	0	0	2299232	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1024	0	0	1025	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.912	0.000	0.000	1.890	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.912	0.000	0.000	1.890	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.820	0.000	0.000	1.844	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.078	0.000	0.000	0.021	0.000	0.000
44	Average BTU per KWh Net Generation	20388.000	0.000	0.000	11523.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Trimble County CT* (d)			Plant Name: *Cane Run NGCC* (e)			Plant Name: (f)			Line No.
Combustion Turbine			Steam						1
Conventional			Conventional						2
2002			2015						3
2004			2015						4
410.00			178.00			0.00			5
369			171			0			6
1186			4075			0			7
328			147			0			8
328			147			0			9
0			0			0			10
0			57			0			11
338766000			618078000			0			12
10526			1762			0			13
11452997			16720974			0			14
112998783			95486956			0			15
41566			20978			0			16
124503872			112230670			0			17
303.6680			630.5094			0			18
0			132076			0			19
19978403			12352391			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
163203			674443			0			25
0			0			0			26
-105			0			0			27
0			0			0			28
0			12291			0			29
0			38560			0			30
0			0			0			31
509250			647196			0			32
0			0			0			33
20650751			13856957			0			34
0.0610			0.0224			0.0000			35
Gas			Gas						36
mcf			mcf						37
3641950	0	0	4271171	0	0	0	0	0	38
1017	0	0	1010	0	0	0	0	0	39
5.486	0.000	0.000	2.892	0.000	0.000	0.000	0.000	0.000	40
5.486	0.000	0.000	2.892	0.000	0.000	0.000	0.000	0.000	41
5.395	0.000	0.000	2.863	0.000	0.000	0.000	0.000	0.000	42
0.059	0.000	0.000	0.020	0.000	0.000	0.000	0.000	0.000	43
10931.000	0.000	0.000	6980.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: -1 Column: c

Cane Run Steam Unit 6 was retired in March 2015 and Cane Run Steam Units 4 and 5 were retired in June 2015.

Schedule Page: 403 Line No.: -1 Column: d

Partnership Expenses included in Column d:

Line No.: 19	Production Expenses: Oper, Supv & Engr	$ (546,011)
Line No.: 20	Fuel	(25,959,015)
Line No.: 22	Steam Expenses	(899,519)
Line No.: 25	Electric Expenses	(273,285)
Line No.: 26	Misc Steam Power Expenses	(1,284,964)
Line No.: 27	Rents	65
Line No.: 28	Allowances	(1,346)
Line No.: 29	Maintenance Supervision and Engineering	(199,211)
Line No.: 30	Maintenance of Structures	(274,561)
Line No.: 31	Maintenance of Boiler Plant	(3,168,835)
Line No.: 32	Maintenance of Electric Plant	(611,949)
Line No.: 33	Maintenance of Misc Steam Plant	(221,616)
Line No.: 34	Total Production Expenses	(33,440,247)

Total Power Production Expenses per Schedule Page: 402-403, Sum of Line No.: 34, Column: b-f	$ 483,062,378
EKPC - Oldham Co. Unit 3 Agreement Fuel Expenses	3,514,459
IMEA-IMPA Partnership Expenses	(33,440,247)
Total Power Production Expenses per Schedule Page: 320-321, Sum of Line No.: 21 & 74, Column: b	$ 453,136,590

Schedule Page: 403 Line No.: 1 Column: d

The Nameplate Rating for Trimble County Steam Unit 1 represents 75% ownership of the 566 MW unit. The Nameplate Rating for Trimble County Steam Unit 2 represents 14.25% ownership of the 838 MW unit. The remaining percentages of Units 1 and 2 are owned by KU, IMEA and IMPA.

Schedule Page: 403 Line No.: 5 Column: f

The Nameplate Rating for Paddy's Run represents 100% ownership of Unit 11, a 16 MW unit, and Unit 12, a 33 MW unit, and 53% ownership of Unit 13, a 178 MW unit, for LG&E. The remaining percentage of Unit 13 is owned by KU.

Schedule Page: 403 Line No.: 11 Column: e

Employees at the Cane Run Plant include those assigned to the steam plant, the Cane Run CT site and the Cane Run NGCC during the year and are reflected in the Cane Run NGCC statistics. The Cane Run Steam plant was retired in 2015.

Schedule Page: 403 Line No.: 11 Column: f

No production/operation employees are directly assigned to Paddy's Run turbines. Employees from the Cane Run Plant operate and maintain the Paddy's Run turbines.

Schedule Page: 402.1 Line No.: 5 Column: c

The Nameplate Rating for Brown CT represents 53% ownership of unit 5, a 123 MW unit, and 38% ownership of units 6 and 7, which are 177 MW each, for LG&E. The remaining percentages of units 5, 6 and 7 are owned by KU.

Schedule Page: 403.1 Line No.: 5 Column: d

The Nameplate Rating for Trimble County CT represents 29% ownership of units 5 and 6, and 37% ownership of units 7, 8, 9 and 10 for LG&E. The remaining percentages for units 5, 6, 7, 8, 9 and 10 are owned by KU. Total Nameplate Ratings for these units are 199 MW per unit.

Schedule Page: 403.1 Line No.: 5 Column: e

The Nameplate Rating for Cane Run NGCC represents 22% ownership of Unit 7, a 808 MW unit. The remaining percentage of Unit 7 is owned by KU.

Schedule Page: 402.1 Line No.: 11 Column: b

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

FOOTNOTE DATA

No production/operation employees are directly assigned to the Zorn station. Employees from the Cane Run Plant maintain the Zorn station. Zorn station is peak load only and is automatically operated.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees at the Brown plant include those assigned to the steam plant and the Brown CT site and are reflected in the Brown steam plant statistics.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees at the Trimble County plant include those assigned to the steam plant and the Trimble County CT site and are reflected in the Trimble County steam plant statistics.

Schedule Page: 403.1 Line No.: 11 Column: e

Employees at the Cane Run Plant include those assigned to the steam plant, the Cane Run CT site and the Cane Run NGCC during the year and are reflected in the Cane Run NGCC statistics. The Cane Run Steam plant was retired in 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 289 Plant Name: Ohio Falls (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1928	
4	Year Last Unit was Installed	1928	
5	Total installed cap (Gen name plate Rating in MW)	96.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	63	0
7	Plant Hours Connect to Load	6,486	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	60	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	7	0
12	Net Generation, Exclusive of Plant Use - Kwh	273,775,000	0
13	Cost of Plant		
14	Land and Land Rights	6	0
15	Structures and Improvements	7,872,008	0
16	Reservoirs, Dams, and Waterways	17,038,183	0
17	Equipment Costs	71,527,692	0
18	Roads, Railroads, and Bridges	29,931	0
19	Asset Retirement Costs	257,805	0
20	TOTAL cost (Total of 14 thru 19)	96,725,625	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,007.5586	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	124,513	0
24	Water for Power	39,039	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	267,947	0
27	Misc Hydraulic Power Generation Expenses	199,153	0
28	Rents	477,265	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	317,142	0
31	Maintenance of Reservoirs, Dams, and Waterways	200,701	0
32	Maintenance of Electric Plant	337,879	0
33	Maintenance of Misc Hydraulic Plant	35,117	0
34	Total Production Expenses (total 23 thru 33)	1,998,756	0
35	Expenses per net KWh	0.0073	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Mill Creek Sub	Paddy's West Sub	345.00	345.00	ST	15.94		2
2	Paddy's West Sub	Kenzig Road	345.00	345.00	ST,SP	5.64		1
3	Trimble County Sub	Clifty Creek Sub	345.00	345.00	ST,WP	12.35		2
4	Blue Lick Sub	Middletown Sub	345.00	345.00	ST	0.12	19.22	1
5	Buckner	Wises Landing	345.00	345.00	ST,SP	0.32	13.11	1
6	Middletown	Buckner	345.00	345.00	ST,SP	0.16	14.13	1
7	Middletown Sub	Trimble County Sub	345.00	345.00	ST	27.96		1
8	Mill Creek Sub	Blue Lick Sub	345.00	345.00	ST	0.24	11.80	1
9	Mill Creek Sub	Middletown Sub	345.00	345.00	ST	31.36		1
10	Paddy's Run Sub	T.V.A. Tower	161.00	161.00	ST	66.16	50.25	2
11	Appl Park Switching Station	Middletown Sub	138.00	138.00	ST	0.08	12.56	1
12	Appl Park Switching Station	Ethel Sub	138.00	138.00	WP,ST	1.95		1
13	Ashbottom Sub	Appl Park Switching Station	138.00	138.00	ST	4.61	1.30	1
14	Grade Lane	Fern Valley Sub	138.00	138.00	ST,SP	2.79		1
15	Ashbottom	Grade Lane	138.00	138.00	ST,SP	0.92		1
16	Ashbottom Sub	Manslick Sub	138.00	138.00	WP,ST	3.43		1
17	Ashby Sub	Pleasure Ridge Park Sub	138.00	138.00	WP,SP,CP	2.82		1
18	Beargrass Sub	Lyndon South Sub	138.00	138.00	ST	0.10	7.33	1
19	Beargrass Sub	Middletown Sub	138.00	138.00	ST	9.06	5.53	2
20	Beargrass Sub	Northside Sub	138.00	138.00	ST,SP	6.37		1
21	Beargrass Sub	Northside Sub	138.00	138.00	ST	0.23	6.11	1
22	Breckenridge Sub	Hurstbourne Sub	138.00	138.00	WP,SP,CP	3.89	0.17	1
23	Campground	Cane Run Switching Station	138.00	138.00	ST	3.08	3.29	2
24	Canal Sub	Waterside West	138.00	138.00	ST	0.23	0.87	1
25	Cane Run Switching Station	Ashbottom Sub	138.00	138.00	ST	9.64	7.87	3
26	Cane Run	Cane Run Switching Station	138.00	138.00	ST,WP	2.39		2
27	Cane Run	Cane Run Switching Station	138.00	138.00	ST,WP	2.28		2
28	Cane Run	Cane Run Switching Station	138.00	138.00	ST	1.37	2.26	1
29	Cane Run	Cane Run Switching Station	138.00	138.00	ST	0.11	2.19	1
30	Cane Run Switching Station	International	138.00	138.00	ST,SP,WP	2.25		1
31	Centerfield Sub	Trimble County Sub	138.00	138.00	WP,ST	15.08	0.67	1
32	Dixie Sub	Algonquin Sub	138.00	138.00	WP,SP	0.80		1
33	Ethel Sub	Breckenridge Sub	138.00	138.00	WP,ST,SP	3.90		1
34	Fern Valley Sub	Okolona Sub	138.00	138.00	WP,SP	1.40		1
35	Fern Valley Sub	Watterson Sub	138.00	138.00	ST	3.92	1.36	1
36					TOTAL	676.34	243.64	88

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 mcm	113,337	5,584,658	5,697,995					1
1024.5 mcm	102,753	5,694,897	5,797,650					2
954 mcm		3,517,965	3,517,965					3
954 mcm		807,000	807,000					4
954 mcm		2,990,335	2,990,335					5
954 mcm		2,696,216	2,696,216					6
954 mcm	479,907	8,519,860	8,999,767					7
954 mcm		693,386	693,386					8
954 mcm	314,954	4,264,302	4,579,256					9
500 mcm	98,666	3,204,097	3,302,763					10
795 mcm	102,525	927,549	1,030,074					11
795 mcm	862	346,118	346,980					12
795 mcm	42,502	490,157	532,659					13
795 mcm		411,830	411,830					14
795 mcm		186,861	186,861					15
795 mcm		561,066	561,066					16
1272 mcm		1,021,519	1,021,519					17
795 mcm		121,582	121,582					18
795 mcm	159,406	1,513,146	1,672,552					19
1024.5 mcm	67,983	3,560,055	3,628,038					20
1024.5 mcm	6,427	1,210,499	1,216,926					21
1272 mcm	15,419	1,425,739	1,441,158					22
795 mcm	8,216	253,452	261,668					23
795 mcm		258,995	258,995					24
795 mcm	38,205	1,462,865	1,501,070					25
795 mcm	18,788	1,615,888	1,634,676					26
795 mcm		191,740	191,740					27
954 mcm		574,206	574,206					28
954 mcm		336,453	336,453					29
795 mcm		613,090	613,090					30
795 mcm	85,784	1,212,183	1,297,967					31
795 mcm	1,446	331,415	332,861					32
1272 mcm	27,072	1,179,516	1,206,588					33
1272 mcm		418,533	418,533					34
795 mcm	2,054	57,683	59,737					35
	9,343,438	191,829,878	201,173,316	287,353	932,134	19,330	1,238,817	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Hurstbourne Sub	Bluegrass Sub	138.00	138.00	SP,WP	2.02		1
2	Knob Creek Sub	Tip Top Sub	138.00	138.00	WP,ST,CP	11.79		1
3	Lyndon South Sub	Middletown Sub	138.00	138.00	ST,SP	5.58		1
4	Magazine Sub	Hancock Sub	138.00	138.00	SP,WP	2.38	0.04	1
5	Magazine Sub	Waterside West	138.00	138.00	ST,SP,WP	3.38		1
6	Manslick Sub	Mill Creek Sub	138.00	138.00	WP,ST	10.52		1
7	Middletown Sub	Centerfield Sub	138.00	138.00	WP,ST	12.26		1
8	Mill Creek Sub	Ashby Sub	138.00	138.00	WP,SP	5.56		1
9	Mill Creek Sub	Knob Creek Sub	138.00	138.00	WP,ST	2.80	3.59	1
10	Mill Creek Sub	Kosmosdale Prim. Meter Stn.	138.00	138.00	WP,ST	1.27	0.44	2
11	Mud Lane Sub	Blue Lick Sub	138.00	138.00	SP,WP	5.45		1
12	Okolona Sub	Mud Lane Sub	138.00	138.00	WP,ST	3.86	0.18	1
13	Paddy's Run Sub	Campground	138.00	138.00	ST	0.45		1
14	Paddy's Run Sub	Dixie Sub	138.00	138.00	WP,SP	3.58		1
15	Paddy's Run Sub	Ohio Falls Sub	138.00	138.00	ST	12.41	0.39	3
16	Paddy's Run Sub	Paddy's West Sub	138.00	138.00	ST	0.69	0.12	2
17	Plainview Sub	Hurstbourne Sub	138.00	138.00	WP,SP	2.18		1
18	Paddy's West Sub	PSI Connection Gallagher	138.00	138.00	SP	0.42		1
19	Northside Sub	Clifty Creek Sub	138.00	138.00	ST,WP	32.54		1
20	Northside Sub	Tower No. 43 at P.S.I.						
21		Connection	138.00	138.00	ST	0.19	0.04	1
22	Clifty Creek Sub	Tower No.220 Connection						
23		with CG&E Co.	138.00	138.00	ST	4.24	2.50	1
24	Watterson Sub	Middletown Sub	138.00	138.00	ST,WP	7.20	0.22	1
25	Tip Top Sub	Cloverport Sub	138.00	138.00	WP,SP,ST	32.81	2.74	1
26	Waterside West	Beargrass Sub	138.00	138.00	ST,SP	2.08		2
27	Waterside West	Beargrass Sub	138.00	138.00	SP	0.25	1.81	1
28	Mill Creek Sub	Cane Run Sub	138.00	138.00	ST,SP	1.55	13.15	1
29	Mill Creek	East Fort Knox	345.00	345.00	HF,ST	6.89		1
30	Middletown	Old Henry	138.00	138.00	ST	3.76		1
31	Old Henry	Collins	138.00	138.00	SP	3.80	0.20	1
32	Trimble County	Speed	345.00	345.00	ST,SP	2.48		1
33	Trimble County	Ghent	345.00	345.00	ST,SP	0.04	2.44	1
34	Kenzig Road	Northside	345.00	345.00	ST,SP	9.19	0.31	1
35	Kenzig Road	Speed Tap	345.00	345.00	SP	0.86		1
36					TOTAL	676.34	243.64	88

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 mcm	37,300	1,164,786	1,202,086					1
636 mcm	7,955	1,168,965	1,176,920					2
795 mcm	35,941	4,734,416	4,770,357					3
1272 mcm		1,805,684	1,805,684					4
795 mcm	2,600	1,232,065	1,234,665					5
636 mcm	16,570	1,488,380	1,504,950					6
795 mcm	42,761	880,596	923,357					7
1272 mcm	528	1,932,380	1,932,908					8
636 mcm	10,855	411,925	422,780					9
840.2 mcm		752,735	752,735					10
840.2 mcm	46,432	2,601,256	2,647,688					11
1272 mcm	79,825	1,363,940	1,443,765					12
795 mcm	1,455	64,918	66,373					13
795 mcm	27,351	937,836	965,187					14
300 mcm	81,226	3,682,734	3,763,960					15
954 mcm	2,763	421,996	424,759					16
1272 mcm	3,591	766,819	770,410					17
954 mcm		219,011	219,011					18
336.4 mcm	73,852	1,550,541	1,624,393					19
								20
954 mcm		45,884	45,884					21
								22
336.4 mcm	22,743	889,814	912,557					23
840.2 mcm		361,979	361,979					24
397.5 mcm	48,020	2,378,933	2,426,953					25
795 mcm	17,950	567,097	585,047					26
795 mcm		913,129	913,129					27
954 mcm	20,979	1,089,717	1,110,696					28
954 mcm	941,552	8,321,901	9,263,453					29
954 mcm		3,435,988	3,435,988					30
954 mcm	10,100	416,299	426,399					31
954 mcm	188,845	15,468,099	15,656,944					32
954 mcm	389,275	1,357,164	1,746,439					33
954 mcm		1,396,543	1,396,543					34
954 mcm		4,180,014	4,180,014					35
	9,343,438	191,829,878	201,173,316	287,353	932,134	19,330	1,238,817	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Kenzig Road	Ramsey Tap	345.00	345.00	SP	0.07	0.80	1
2	Overhead Lines under							
3	132KV		69.00	69.00	WP,ST	232.12	54.65	
4	Ashbottom Sub	Grade Lane Sub	138.00	138.00	Undg. (26)	0.58		1
5	Waterside West	Canal Sub	138.00	138.00	Undg. (26)	0.75		1
6	Magazine Sub	Waterside West	138.00	138.00	Undg. (26)	0.75		1
7	Waterside West	Beargrass Sub	138.00	138.00	Undg. (26)	0.93		1
8	Waterside West	Beargrass Sub	138.00	138.00	Undg. (26)	0.93		1
9	Underground Lines under							
10	132KV		69.00	69.00	Undg. (26)	2.78		
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34	Exp Applicable to All Lines							
35								
36					TOTAL	676.34	243.64	88

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 mcm		4,180,014	4,180,014					1
								2
Various	5,546,663	52,643,985	58,190,648					3
1500 Kcmil cu		1,042,460	1,042,460					4
1750 mcm ho		584,760	584,760					5
1500 mcm ho		584,626	584,626					6
1500 mcm cu		1,659,275	1,659,275					7
1500 mcm ho		1,465,974	1,465,974					8
								9
Various		3,410,384	3,410,384					10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
				287,353	932,134	19,330	1,238,817	34
								35
	9,343,438	191,829,878	201,173,316	287,353	932,134	19,330	1,238,817	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Mill Creek	Paddy's West	1.40	ST,SP		1	
2	Kenzig Road	Speed Tap	0.86	SP		1	
3	Kenzig Road	Ramsey Tap	0.87	SP		1	
4	Paddy's West	Kenzig Road	0.29	ST,SP		1	
5	Kenzig Road	Northside	0.29	ST,SP		1	
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
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21							
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23							
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26							
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32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		3.71			5	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
954 mcm					1,484,506	862,411		2,346,917	1
954 mcm					2,090,007	2,090,007		4,180,014	2
954 mcm					2,090,007	2,090,007		4,180,014	3
1024.5 mcm					696,669	696,669		1,393,338	4
1024.5 mcm					696,669	696,669		1,393,338	5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
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									43
					7,057,858	6,435,763		13,493,621	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Aiken	Transmission*	69.00		
2	Algonquin	Transmission*	138.00	69.00	13.80
3	Appliance Park	Transmission*	138.00		
4	Ashbottom	Transmission*	138.00	69.00	13.80
5	Beargrass	Transmission*	138.00	69.00	13.80
6	Beargrass Pumping	Transmission*	69.00		
7	Blue Lick, Brooks, KY	Transmission*	345.00	138.00	
8	Blue Lick, Brooks, KY	Transmission*	345.00	161.00	
9	Blue Lick, Brooks, KY	Transmission*	138.00	69.00	13.80
10	Breckenridge	Transmission*	138.00	69.00	13.20
11	Canal	Transmission*	136.80	66.00	14.00
12	Cane Run Switching	Transmission*	138.00	69.00	13.80
13	Centerfield	Transmission*	138.00	69.00	13.80
14	Clay	Transmission*	69.00		
15	Clifton	Transmission*	69.00		
16	Cloverport	Transmission*	138.00		
17	Collins	Transmission*	138.00	69.00	
18	Eastwood	Transmission*	69.00		
19	Ethel	Transmission*	138.00	69.00	13.80
20	Farnsley	Transmission*	69.00		
21	Fern Valley	Transmission*	138.00	69.00	13.80
22	Ford	Transmission*	69.00		
23	Grady	Transmission*	69.00		
24	Hancock	Transmission*	138.00	69.00	13.80
25	Harrods Creek	Transmission*	69.00		
26	Kenzig Road	Transmission*	345.00		
27	Lyndon	Transmission*	69.00		
28	Lyndon South, Lyndon, KY	Transmission*	138.00	69.00	13.80
29	Madison	Transmission*	69.00		
30	Middletown, Middletown, KY	Transmission*	345.00	138.00	
31	Middletown, Middletown, KY	Transmission*	138.00	69.00	
32	Middletown, Middletown, KY	Transmission*	138.00	69.00	13.80
33	Mill Creek, Kosmosdale, KY	Transmission*	345.00	138.00	13.80
34	Mill Creek, Kosmosdale, KY	Transmission*	138.00	69.00	13.80
35	Mill Creek, Kosmosdale, KY	Transmission*	138.00	69.00	14.00
36	Mud Lane	Transmission*	138.00	69.00	13.80
37	Northside, Jeffersonville, IN	Transmission*	345.00	138.00	13.80
38	Oxmoor	Transmission*	69.00		
39	Paddy's Run	Transmission*	161.00	138.00	
40	Paddy's Run	Transmission*	138.00	69.00	14.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
			NONE			1
140	1		NONE			2
			NONE			3
224	2		NONE			4
185	1		NONE			5
			NONE			6
448	1		NONE			7
240	1		NONE			8
112	1		NONE			9
112	1		NONE			10
93	1		NONE			11
224	2		NONE			12
140	1		NONE			13
			NONE			14
			NONE			15
			NONE			16
149	1		NONE			17
			NONE			18
140	1		NONE			19
			NONE			20
80	2		NONE			21
			NONE			22
			NONE			23
140	1		NONE			24
			NONE			25
			NONE			26
			NONE			27
140	1		NONE			28
			NONE			29
1794	4		NONE			30
150	1		NONE			31
298	2		NONE			32
672	2		NONE			33
40	1		NONE			34
40	1		NONE			35
120	1		NONE			36
448	1		NONE			37
			NONE			38
200	1		NONE			39
187	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Paddy's West - IN	Transmission*	345.00	138.00	13.80
2	Seminole	Transmission*	69.00		
3	Shively	Transmission*	69.00		
4	Smyrna	Transmission*	69.00		
5	Taylor	Transmission*	69.00		
6	Tip Top, KY	Transmission*	135.00	66.00	14.00
7	Tip Top, KY	Transmission*	135.00	66.00	37.00
8	Trimble County CT	Transmission*	345.00		
9	Trimble County	Transmission*	345.00	138.00	
10	Waterside West	Transmission*	138.00		
11	Watterson	Transmission*	138.00	69.00	13.80
12	Worthington	Transmission*	69.00		
13	Total Transmission		7881.80	2636.00	340.80
14					
15	Aiken	Distribution*	69.00	12.47	
16	Algonquin	Distribution*	69.00	13.80	
17	Ashbottom	Distribution*	138.00	13.80	
18	Ashby	Distribution*	138.00	12.47	
19	Bishop	Distribution*	69.00	12.47	
20	Bluegrass	Distribution*	138.00	12.47	
21	Brandenburg, near Brandenburg, KY	Distribution*	69.00	12.47	
22	Breckenridge	Distribution*	69.00	13.80	
23	Breckenridge	Distribution*	69.00	12.47	
24	Campground	Distribution*	138.00	13.80	
25	Canal	Distribution*	69.00	13.80	
26	Cane Run	Distribution*	69.00	13.80	
27	Centerfield	Distribution*	138.00	12.47	
28	Clay	Distribution*	69.00	13.80	
29	Clifton	Distribution*	69.00	13.80	
30	Clifton	Distribution*	69.00	12.47	
31	Collins	Distribution*	69.00	12.47	
32	Conestoga	Distribution*	69.00	12.47	
33	Crestwood, Crestwood, KY	Distribution*	69.00	12.47	
34	Crop	Distribution*	13.80	4.16	
35	Dahila	Distribution*	69.00	12.47	
36	Del Park	Distribution*	69.00	13.80	
37	Dixie	Distribution*	138.00	12.47	
38	Eastwood West	Distribution*	69.00	12.47	
39	Ethel	Distribution*	69.00	13.80	
40	Ethel	Distribution*	69.00	12.47	

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
448	1		NONE			1
			NONE			2
			NONE			3
			NONE			4
			NONE			5
33	1		NONE			6
45	1		NONE			7
			NONE			8
448	2		NONE			9
			NONE			10
152	2		NONE			11
			NONE			12
7642	40					13
						14
73	2		NONE			15
101	3		Ground Transformer	4	12	16
95	2		Ground Transformer	2	10	17
56	2		NONE			18
56	2		NONE			19
90	2		NONE			20
11	1		NONE			21
40	2		Ground Transformer	2	5	22
84	3		NONE			23
45	1		Ground Transformer	1	5	24
60	2		Ground Transformer	2	8	25
120	2		Ground Transformer	9	60	26
45	1		NONE			27
50	2		Ground Transformer	2	10	28
48	2		Ground Transformer	2	9	29
56	2		NONE			30
56	2		NONE			31
28	1		NONE			32
56	2		NONE			33
12	2		NONE			34
56	2		NONE			35
45	1		Ground Transformer	1	5	36
45	1		NONE			37
45	1		NONE			38
25	1		Ground Transformer	1	4	39
56	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Fairmount	Distribution*	69.00	12.47	
2	Farnsley Shively, KY	Distribution*	69.00	12.47	
3	Fern Valley	Distribution*	138.00	13.80	
4	Fern Valley	Distribution*	138.00	12.47	
5	Floyd	Distribution*	69.00	13.80	
6	Ford Truck Plant	Distribution*	69.00	12.47	
7	Frey's Hill	Distribution*	69.00	12.47	
8	Grade Lane	Distribution*	138.00	13.80	
9	Grady	Distribution*	69.00	13.80	
10	Hancock	Distribution*	138.00	12.47	
11	Harmony Landing, near Goshen, KY	Distribution*	69.00	12.47	
12	Harrod's Creek	Distribution*	69.00	12.47	
13	Herman - Class B	Distribution*	13.80	4.16	
14	Highland #1	Distribution*	69.00	12.47	
15	Highland	Distribution*	69.00	13.80	
16	Hillcrest	Distribution*	69.00	12.47	
17	Hillcrest	Distribution*	69.00	13.80	
18	Hurstbourne, Jeffersontown, KY	Distribution*	138.00	12.47	
19	International	Distribution*	138.00	12.47	
20	Jeffersontown	Distribution*	69.00	12.47	
21	Kenwood	Distribution*	69.00	12.47	
22	Knob Creek, near Shepherdsville, KY	Distribution*	138.00	34.50	14.00
23	Locust	Distribution*	69.00	12.47	
24	Lyndon, KY	Distribution*	69.00	12.47	
25	Lyndon South	Distribution*	69.00	12.47	
26	Lynn	Distribution*	13.80	4.16	
27	Madison	Distribution*	69.00	13.80	
28	Magazine	Distribution*	13.80	4.16	
29	Magazine	Distribution*	69.00	13.80	
30	Manslick	Distribution*	138.00	12.47	
31	Mill Creek	Distribution*	138.00	12.47	
32	Mud Lane	Distribution*	138.00	12.47	
33	Nachand	Distribution*	69.00	12.47	
34	Okolona	Distribution*	138.00	12.47	
35	Old Henry	Distribution*	138.00	12.47	
36	Oxmoor	Distribution*	69.00	12.47	
37	Paddy's Run	Distribution*	138.00	13.80	
38	Pirtle	Distribution*	13.80	4.16	
39	Plainview	Distribution*	138.00	12.47	
40	Pleasure Ridge Park	Distribution*	138.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
73	2		NONE			1
56	2		NONE			2
78	2		Ground Transformer	2	9	3
101	3		NONE			4
45	1		Ground Transformer	1	5	5
134	2		NONE			6
73	2		NONE			7
202	3		Ground Transformer	2	10	8
66	3		Ground Transformer	2	9	9
45	1		NONE			10
28	1		NONE			11
84	3		NONE			12
11	2		NONE			13
45	1		Ground Transformer	1	5	14
34	1		NONE			15
45	1		Ground Transformer	1	5	16
34	1		NONE			17
90	2		NONE			18
90	2		NONE			19
73	2		NONE			20
56	2		NONE			21
30	1		NONE			22
45	1		NONE			23
28	1		NONE			24
73	2		NONE			25
12	2		NONE			26
134	3		Ground Transformer	2	10	27
15	2		Ground Transformer	3	15	28
111	3		NONE			29
45	1		NONE			30
28	1		Ground Transformer	2	19	31
90	2		NONE			32
84	3		NONE			33
45	1		NONE			34
45	1		NONE			35
56	2		NONE			36
335	6		Ground Transformer	5	70	37
14	2		NONE			38
45	1		NONE			39
45	1		NONE			40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Seminole	Distribution*	69.00	13.80	
2	Seminole	Distribution*	69.00	12.47	
3	Seventh Street	Distribution*	13.80	4.16	
4	Shepherdsville, KY	Distribution*	69.00	12.47	
5	Shively	Distribution*	69.00	12.47	
6	Shively	Distribution*	69.00	13.80	
7	Skylight, KY	Distribution*	69.00	12.47	
8	Smyrna	Distribution*	69.00	12.47	
9	South Park	Distribution*	69.00	12.47	
10	South Park	Distribution*	69.00	34.50	14.00
11	Southern	Distribution*	13.80	4.16	
12	Stewart	Distribution*	69.00	12.47	
13	Taylor	Distribution*	69.00	12.47	
14	Terry	Distribution*	69.00	12.47	
15	Tip Top	Distribution*	138.00	34.50	28.00
16	Waterside West	DIstribution*	138.00	13.80	
17	Watterson	Distribution*	138.00	12.47	
18	West Point	Distribution*	34.50	12.47	
19	Western	Distribution*	13.80	4.16	
20	Worthington	Distribution*	69.00	12.47	
21	WHAS	Distribution*	69.00	12.47	
22	20 Stations Less Than 10 MVa				
23	Total Distribution		7182.90	1113.76	56.00
24					
25					
26					
27					
28					
29					
30	Summary				
31	Transmission 46				
32	Distribution 97				
33	Total 143				
34					
35	* Unattended				
36					
37					
38					
39					
40					

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
229	5		NONE			1
45	1		NONE			2
14	2		NONE			3
21	2		NONE			4
45	1		Ground Transformer	1	5	5
25	1		NONE			6
10	1		NONE			7
56	2		NONE			8
28	1		NONE			9
10	1		NONE			10
14	2		NONE			11
62	3		NONE			12
84	3		NONE			13
73	2		NONE			14
101	2		NONE			15
200	4		NONE			16
73	2		NONE			17
11	1		NONE			18
14	2		NONE			19
90	2		NONE			20
20	2		NONE			21
104	27		NONE			22
5526	190			48	290	23
						24
						25
						26
						27
						28
						29
						30
7642	40					31
5526	190			48	290	32
13168	230			48	290	33
						34
						35
						36
						37
						38
						39
						40

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital Expenditures	Kentucky Utilities Company	see footnote	2,263,125
3	Direct-Indirect Labor	Kentucky Utilities Company	see footnote	1,127,580
4	Equipment and Facilities	Kentucky Utilities Company	see footnote	422,150
5	Office and Administrative Services	Kentucky Utilities Company	see footnote	55,729
6	Materials and Fuels	Kentucky Utilities Company	see footnote	90,054
7	Outside Services	Kentucky Utilities Company	see footnote	165,269
8	Transmission	Kentucky Utilities Company	see footnote	499,624
9				
10	Capital Expenditures	LG&E and KU Services Company	see footnote	31,847,103
11	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	87,784,776
12	Equipment and Facilities	LG&E and KU Services Company	see footnote	12,391,593
13	Office and Administrative Services	LG&E and KU Services Company	see footnote	5,780,530
14	Materials	LG&E and KU Services Company	see footnote	2,829,528
15	Outside Services	LG&E and KU Services Company	see footnote	16,478,786
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Capital Expenditures	Kentucky Utilities Company	see footnote	8,047,576
22	Direct-Indirect Labor	Kentucky Utilities Company	see footnote	16,195,556
23	Equipment and Facilities	Kentucky Utilities Company	see footnote	797,376
24	Office and Administrative Services	Kentucky Utilities Company	see footnote	5,379
25	Materials and Fuels	Kentucky Utilities Company	see footnote	232,966
26	Outside Services	Kentucky Utilities Company	see footnote	237,141
27	Transmission	Kentucky Utilities Company	see footnote	358,144
28				
29	Capital Expenditures	LG&E and KU Services Company	see footnote	141,161
30	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	648,896
31	Equipment and Facilities	LG&E and KU Services Company	see footnote	315,857
32	Office and Administrative Services	LG&E and KU Services Company	see footnote	35,265
33	Materials	LG&E and KU Services Company	see footnote	12,193
34	Outside Services	LG&E and KU Services Company	see footnote	522,647
35				
36	Direct-Indirect Labor	PPL Services Corporation	see footnote	622
37	Equipment and Facilities	PPL Services Corporation	see footnote	356,226
38				
39				
40				
41				
42	See footnote for allocation process			

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FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 3 Column: c
Accounts charged include: 163, 184, 408.1, 426.5, 500, 502, 505, 506, 546, 549, 551-554, 560, 561.2, 580, 583, 588, 592, 593, 595, 598, 901, 903, 920, 922, 925, 926 and 935

Schedule Page: 429 Line No.: 4 Column: c
Accounts charged include: 163, 184, 426.4, 426.5, 500-502, 506, 510, 512, 513, 550, 552, 553, 560-563, 566, 567, 570, 571, 573, 580, 582-584, 586, 588, 590, 592-594, 596, 598, 836, 878, 901, 903, 907, 921, 923, 925, 931 and 935

Schedule Page: 429 Line No.: 5 Column: c
Accounts charged include: 151, 184, 426.5, 500, 506, 510, 566, 571, 580, 588, 593, 874, 901, 903, 921 and 930.2

Schedule Page: 429 Line No.: 6 Column: c
Accounts charged include: 163, 184, 426.5, 501, 511-514, 553, 560, 562, 570, 571, 573, 582, 588, 593 and 921

Schedule Page: 429 Line No.: 7 Column: c
Accounts charged include: 163, 184, 500, 510, 552, 553, 560, 562, 566, 570, 571, 573, 593, 902 and 923

Schedule Page: 429 Line No.: 8 Column: c
Accounts charged include: 565

Schedule Page: 429 Line No.: 10 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 11 Column: c
Accounts charged include: 143, 163, 182.3, 183, 184, 232, 408.1, 426.4, 426.5, 500-502, 506, 510-514, 544, 546, 549, 553, 554, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592, 593, 598, 814, 817, 818, 850, 851, 874, 880, 887, 901-903, 905, 907, 908, 920, 921, 925, 926, 930.2 and 935

Schedule Page: 429 Line No.: 12 Column: c
Accounts charged include: 143, 163, 165, 183, 184, 426.4, 426.5, 500-502, 506, 510-514, 544, 546, 553, 556, 560, 561.1, 561.5, 563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 590, 592, 593, 598, 814, 817, 818, 850, 851, 874, 880, 887, 892, 901-903, 905, 907, 908, 921, 923, 930.2, 931 and 935

Schedule Page: 429 Line No.: 13 Column: c
Accounts charged include: 184, 186, 408.2, 426.4, 426.5, 500-502, 506, 510-513, 539, 549, 553, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592, 593, 595, 598, 807, 814, 818, 821, 850, 856, 863, 874, 880, 887, 892, 901-903, 905, 907, 908-910, 913, 920, 921, 924, 930.2 and 935

Schedule Page: 429 Line No.: 14 Column: c
Accounts charged include: 163, 165, 184, 426.4, 426.5, 500-502, 506, 510-514, 539, 542, 545, 549, 553, 554, 560, 561.1, 561.5, 566, 570, 573, 580, 582, 586, 588, 593, 598, 817, 818, 821, 833, 837, 850, 874, 878, 880, 887, 892, 894, 902, 903, 907, 908, 921, 923, 930.2 and 935

Schedule Page: 429 Line No.: 15 Column: c
Accounts charged include: 165, 184, 186, 188, 426.4, 426.5, 500-502, 506, 510-514, 542, 545, 549, 552-554, 556, 560-562, 566, 570, 573, 580, 582, 583, 586, 588, 592, 593, 598, 807, 817, 818, 821, 833, 837, 850, 851, 875, 880, 887, 892, 894, 901-903, 908, 909, 921, 923, 930.2 and 935

Schedule Page: 429 Line No.: 21 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 22 Column: c
Accounts charged include: 163, 182.3, 184, 232, 408.1, 426.4, 426.5, 500-502, 505, 506, 510-514, 546, 548, 549, 551-554, 560, 561.2, 561.5, 562, 566, 570, 580, 582, 583, 586, 588, 592, 593, 595, 598, 901, 903, 907, 908, 920, 925, 926 and 935

Schedule Page: 429 Line No.: 23 Column: c
Accounts charged include: 163, 184, 426.4, 426.5, 454, 493, 500-502, 506, 510, 512, 513,

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549-554, 560-563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 590, 592-595, 598, 901-903, 907, 908, 921, 923, 931 and 935

Schedule Page: 429 Line No.: 24 Column: c

Accounts charged include: 151, 184, 426.5, 500, 502, 506, 510, 549, 556, 566, 570, 580, 582, 586, 588, 901, 903, 908, 921 and 935

Schedule Page: 429 Line No.: 25 Column: c

Accounts charged include: 163, 184, 502, 506, 511-514, 550, 553, 554, 570, 580, 582, 583, 586, 588, 592, 593, 598, 903, 921, 923 and 935

Schedule Page: 429 Line No.: 26 Column: c

Accounts charged include: 184, 186, 500, 506, 512, 513, 549, 552-554, 560, 562, 563, 566, 570, 571, 573, 580, 582, 586, 588, 923 and 935

Schedule Page: 429 Line No.: 27 Column: c

Accounts charged include: 456.1

Schedule Page: 429 Line No.: 29 Column: c

Accounts charged include: 107

Schedule Page: 429 Line No.: 30 Column: c

Accounts charged include: 163, 184, 408.1 426.4, 426.5, 500, 501, 506, 510, 560, 561.2, 561.5, 566, 570, 580, 586, 588, 901, 903, 907, 920, 925, 930.2 and 935

Schedule Page: 429 Line No.: 31 Column: c

Accounts charged include: 184 and 921

Schedule Page: 429 Line No.: 32 Column: c

Accounts charged include: 184, 921 and 935

Schedule Page: 429 Line No.: 33 Column: c

Accounts charged include: 184 and 921

Schedule Page: 429 Line No.: 34 Column: c

Accounts charged include: 184, 921 and 923

Schedule Page: 429 Line No.: 36 Column: c

Accounts charged include: 920

Schedule Page: 429 Line No.: 37 Column: c

Accounts charged include: 454, 493 and 921

Schedule Page: 429 Line No.: 42 Column: a

Costs between Louisville Gas and Electric Company and Kentucky Utilities Company are charged directly and are not allocated.

LG&E and KU Services Company (LKS) will allocate the costs of service among the affiliated companies using one of several methods that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. Any of the methods may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes in the business, but are generally determined annually. The assignment methods used by LKS are as follows:

Contract Ratio – Based on the sum of the physical amount (i.e. tons of coal, mmbtu of natural gas) of the contract for coal and natural gas fuel burned for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Departmental Charge Ratio – A specific LKS department ratio based upon various factors. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of service being performed and are documented and monitored by the Budget Coordinators for each department. The numerator and denominator vary by department. The ratio is based upon various factors such as labor hours, labor dollars, departmental or entity headcount, capital

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expenditures, operations and maintenance costs, retail energy sales, charitable contributions, generating plant sites, average allocation of direct reports, net book value of utility plant, total line of business assets, electric capital expenditures, substation assets and transformer assets. These ratios are calculated on an annual basis. Any changes in these ratios will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in any of these ratios from that used in the prior year.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Generation Ratio – Based on the annual forecast of megawatt hours, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Non-Fuel Material and Services Expenditures – Based on non-fuel material and services expenditures, net of reimbursements, for the immediately preceding twelve consecutive calendar months. The numerator is equal to such expenditures for a specific entity and/or line-of-business as appropriate and the denominator is equal to such expenditures for all applicable entities. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Customers Ratio – Based on the number of retail electric and/or gas customers. This ratio will be determined based on the actual number of customers at the end of the previous calendar year. In some cases, the ratio may be calculated based on the type of customer class being served (i.e. Residential, Commercial or Industrial). The numerator is the total number of each Company’s retail customers. The denominator is the total number of retail customers for both LG&E and KU. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Employees Ratio – Based on the number of employees benefiting from the performance of a service. This ratio will be determined based on actual counts of applicable employees at the end of the previous calendar year. A two-step assignment methodology is utilized to properly allocate LKS employee costs to the proper legal entity. The numerator for the first step of this ratio is the total number of employees for each specific company, and the denominator is the total number of employees for all companies in which an allocator is assigned (i.e. LG&E, KU and LKS). For the second step, the ratio of LKS to total employees will then be allocated to the other companies (LG&E, KU and LKC) based on each company’s ratio of labor dollars to total labor dollars. LKC has no employees, but non-utility related labor is charged to it. In some cases, the ratio may be calculated based on the number of employees at a specific location for the first step with the ratio of LKS to total employees being allocated based on labor hours of the employees at the specific location. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Meters Ratio – Based on the number or types of meters being utilized by customer classes within the system for the immediately preceding twelve consecutive calendar

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months. The numerator is equal to the number of meters for each utility and the denominator is equal to the total meters for KU and LG&E. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Transactions Ratio – Based on the number of transactions occurring in the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. The Controller's organization is responsible for maintaining and monitoring specific product/service methodology documentation for actual transactions related to LKS billings. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Revenue Ratio – Based on the sum of the revenue for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Revenue, Total Assets and Number of Employees Ratio – Based on an average of the revenue, total assets and number of employees ratios. The numerator is the sum of Revenue Ratio, Total Assets Ratio and Number of Employees Ratio for the specific company. The denominator is three – the number of ratios being averaged. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Total Assets Ratio – Based on the total assets at year-end for the preceding year. In the event of joint is the total assets for each specific company at the end of the preceding year. The denominator is the sum of total assets for each company in which an allocator is assigned (LG&E, KU and LKC). This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Total Utility Plant Assets Ratio – Based on the total utility plant assets at year-end for the preceding year, the numerator of which is for an operating company and the denominator of which is for all operating companies. In the event of joint ownership of a specific asset, ownership percentages are utilized to assign costs. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Transmission Ratio –The Transmission Coordination Agreement (TCA) provides "the contractual basis for the coordinated planning, operation, and maintenance of the combined" LG&E and KU transmission system. Pursuant to the terms of the TCA, LG&E/KU "operate their transmission systems as a single control area." The TCA establishes cost and revenue allocations between LG&E and KU. The Transmission Ratio is based upon Schedule A (Allocation of Operating Expenses of the Transmission System Operator) of the TCA. Transmission System Operator Company allocation percentages are calculated during June of each year to be effective July 1st of each year using the previous year's summation of the Transmission Peak Demands as found in FERC Form 1 for Kentucky Utilities Company (KU) and Louisville Gas & Electric Company (LG&E) page 400 line 17(b).

Transportation Resource Management System Chargeback Ratio – Based on the costs associated with providing and operating transportation fleet for all affiliated companies including

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FOOTNOTE DATA

developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities. This ratio is calculated monthly based on the actual transportation charges from the previous month. The numerator is the department labor charged to a specific company. The denominator is the total labor costs for the specific department. The ratio is then multiplied by the total transportation costs to determine the amount charged to each company.

Ownership Percentages – Based on the contractual ownership percentages of jointly-owned generating units, information technology, facilities and other capital projects. This ratio is updated as a result of a new jointly-owned capital projects and is based on the benefit to the respective company. The numerator is the specific company’s forecasted usage. The denominator is the total forecasted usage of all respective companies.

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a PPL company

ANNUAL REPORT

Major Natural Gas Companies

Public Service Commission
of Kentucky

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Louisville Gas and Electric Company	End of 2015/Q4

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Principal Payment and Interest Information

	Amount	Yes/No
Amount of Principal Payment During Calendar Year	$250,000,000.00	
Is Principal Current?	Y	
Is Interest Current?	Y	

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Services Performed by Independent CPA

	Yes/No	A/C/R
Are your financial statements examined by a Certified Public Accountant?		
Enter Y for Yes or N for No	Y	
If yes, which service is performed?		
Enter an X on each appropriate line		
Audit		X
Compilation		
Review		
Please enclose a copy of the accountant’s report with annual report.		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Purchases

	Seller	Acct	Gas Purc MCF	Cost of Gas
	Gas Purchases	803	33,611,882	$119,359,573.00
	Performance Based Ratemaking Incentive	803	0	$519,042.00
	Gas Supply Adjustments	803	0	$13,970,620.00
	Wholesale Purchases	803	0	$0.00
Total			33,611,882	$133,849,235.00

Note:
See Notes 1 and 4 of Notes to Financial Statements for a description of the Performance Based Ratemaking Incentive in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Additional Information - Counties

Barren, Bullitt, Green, Hardin, Hart, Henry, Jefferson, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Spencer, Trimble, Washington

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Revenues, Customers and MCF Sales

	Revenues	MCFs Nat Gas Sold	Customers
Residential (480)	$206,847,666.00	18,840,133	294,527
Commercial and Industrial Sales (481)			
Small (or Commercial)	$77,411,303.00	8,798,204	24,919
Large (Or Industrial)	$9,977,988.00	1,382,263	356
Other Sales to Public Authorities (482)	$10,027,028.00	1,272,270	1,122
Interdepartmental Sales (484)	$4,771,518.00	411,902	1
Total Sales to Ultimate Customers	$309,035,503.00	30,704,772	320,925
Sales for Resale (483)	$0.00	0	0
Total Natural Gas Service	$309,035,503.00	30,704,772	320,925

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Identification (Ref Page: 1)

	Name	Address1	Address2	City	State	Zip	Phone
Exact Legal Name of Respondent							
	Louisville Gas and Electric Company						
Previous Name and Date of change (if name changed during the year)							
Name Address and Phone number of the contact person							
	T. Eric Raible	220 West Main Street	P.O. Box 32030	Louisville	KY	40202	(502) 627-3426
Note File: Attestation and signature via Electronic Filing							

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

General Information - (1) (Ref Page: 101)

	Name	Address	City	State	Zip
Provide name and title of the Officer having custody of the general corporate books of account	Kent W. Blake, Chief Financial Officer				
Provide Address of Office where the general Corporate books are kept		220 West Main Street	Louisville	KY	40202
Provide the Address of any other offices where other coprorate books are kept if different from where the general corporate books are kept					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

General Information (2,3,4) (Ref Page: 101)

	Explain
Provide the name of the State under the laws which respondent is incorporated and date	
If incorporated under a special law give reference to such law	
If not incorporated state that fact and give the type of organization and the date organized	
	Kentucky July 2, 1913
If at any time during the year the property of respondent was held by a receiver or trustee	
give (a) the name of receiver or trustee	
(b) date such receiver or trustee took possession	
(c) the authority by which the receivership or trusteeship was created and	
(d) date when possession by receiver or trustee ceased.	
	Not Applicable
State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.	
	Respondent furnishes electric and natural gas services in Metro Louisville and adjacent territory in Kentucky.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

General Information - (5) (Ref Page: 101)

	Yes/No	Date
Have you engaged as the principal acountant to audit your financial statements an accountant who is not the principal account for the previous years certified financial statements?		
Enter Y for Yes or N for No	N	
If yes, Enter the date when such independend accountant was initially engaged		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Corporations Controlled by Respondent (Ref Page: 103)

Name of Company (a)	Type (b)	Business (c)	Percent Voting Stock (d)
Not Applicable			0.00000000

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Security Holders and Voting Powers - Part 1 (Ref Page: 107)

	Explain	Date	Total
1. Give date of the latest closing of the stock book prior to end of the year, and state the purpose of such closing:	Stock books not closed during the year.		
2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors or the respondent and the number of such votes cast by proxy			
Total:			21,294,223
By Proxy:			21,294,223
3. Give the date and place of such a meeting	Louisville, KY	6/2/2015	
Voting Securities			
Number of votes as of Date:			21,294,223

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Security Holders and Voting Powers - Part 2 (Ref Page: 107)

	Name	Address	Total Votes	Common Stock	Preferred Stock	Other
4. Total votes of all voting securities			21,294,223	21,294,223	0	0
5. Total number of all security holders			1	1	0	0
6. Total Votes of Security Holders listed below						
	LG&E and KU Energy LLC	Louisville, KY	21,294,223	21,294,223	0	0

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Important Changes During the Year (Ref Page: 108)

	Explain
Give particulars concerning the matters indicated below.	
1. Changes in and important additions to franchise rights:	None.
2. Acquisition of ownership in other companies by reorganization, merger or consolidation with other companies:	None.
3. Purchase or sale of an operating unit or system:	On June 23, 2015, LG&E and KU completed an early termination and repurchase transaction under an existing joint lease regarding two 146 MW combustion turbine generating units located at the E.W. Brown Station (Brown Units 6 & 7) operated and maintained by LG&E and KU. The early termination and repurchase transaction occurred pursuant to provisions in such lease. LG&E and KU received FERC authorization in FERC Docket No. EC15-78-000. Per Docket No. EC15-78-000, the termination and repurchase transaction did not involve any accounting entries for LG&E.
4. Important leaseholds (other than leaseholds for natural gas lands) thant have been accquired or given assigned or surrendered:	None of a material nature.
5. Important extension or reduction of transmission or distribution system:	None.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees.	LG&E received FERC authorization in FERC Docket No. ES15-67-000 for up to $500 million in the form of money pool debt, commercial paper or any other type of short-term loan through November 30, 2017. LG&E's money pool balance was zero at December 31, 2015, and December 31, 2014. LG&E's commercial paper program limit is $350 million as of April 30, 2013. As of December 31, 2015, and December 31, 2014, the outstanding commercial paper balance is $142 million and $264 million, respectively. On September 28, 2015, LG&E issued $550 million of first mortgage bonds of which $300 million was issued at an interest rate of 3.30% and will be due October 1, 2025, and $250 million was issued at an interest rate of 4.375% and will be due October 1, 2045. These bonds were issued pursuant to a Kentucky Public Service Commission Order in Case No. 2014-00089 dated June 16, 2014, and amended July 1, 2014. LG&E has a revolving credit facility totaling $500 million. The facility was approved by the Kentucky Public Service Commission Order, Case No. 2010-00205 on September 30, 2010. There were no borrowings outstanding under this facility at December 31, 2015, and December 31, 2014. On January 29, 2016, LG&E amended this revolving credit facility to extend the termination date from July 28, 2019, to December 31, 2020. The extension was approved by the Kentucky Public Service Commission Order, Case No. 2015-00138 on July 2, 2015.
7. Changes in articles of incoporation or amendments to charter: Explain the nature and purpose of such changes or amendments.	None.
8. State the estimated annual effect and nature of any important wage scale changes during the year.	During the first quarter of 2015, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. As outlined in the IBEW Local 2100 contract, union employees received a negotiated 2.5% wage increase effective November 9, 2015.
9. State briefly the status of any materially important legal proceedings pending at the end of the year and the results.	See Notes 4 and 8 of Notes to Financial Statements on page 123.
10. Describe briefly any materially important transactions not disclosed elsewhere in this report in which an officer, director, or associated company was a party or had a material interest.	None.
11. Estimated increase or decrease in annual revenues caused by important rate changes.	On June 30, 2015, LG&E received authorization in Kentucky Public Service Commission Order, Case No. 2014-00372 to increase base rate revenues by $7 million for services rendered on and after July 1, 2015.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$5,704,302,005.00	$6,131,439,950.00
3, Construction Work in Progress (107)	$676,320,025.00	$389,846,496.00
4. TOTAL UTILITY PLANT	$6,380,622,030.00	$6,521,286,446.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$2,416,826,220.00	$2,015,937,460.00
6. Net Utility Plant (Line 4 less Line 5)	$3,963,795,810.00	$4,505,348,986.00
7. Nuclear Fuel (120.1-120.4,120.6)	$0.00	$0.00
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	$0.00	$0.00
9. Nuclear Fuel (Line 7 less Line 8)	$0.00	$0.00
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$3,963,795,810.00	$4,505,348,986.00
11. Utility Plant Adjustments (116)	$0.00	$0.00
12. Gas Stored-Base Gas (117.1)	$2,139,990.00	$2,139,990.00
13. System Balancing Gas (117.2)	$0.00	$0.00
14. Gas Stored Underground - Non Current (117.3)	$0.00	$0.00
15. Gas Owned to System Gas (117.4)	$0.00	$0.00
16. OTHER PROPERTY AND INVESTMENTS		
17. Nonutility Property (121)	$631,414.00	$630,897.00
18. (Less) Accum. Prov. for Depr and Amort. (122)	$63,362.00	$63,362.00
19. Investment in Associated Companies (123)	$0.00	$0.00
20. Investments in Subsidiary Companies (123.1)	$594,286.00	$594,286.00
21.		
22. Noncurrent Portion of Allowances	$0.00	$0.00
23. Other Investments (124)	$0.00	$0.00
24. Special Funds (125-128)	$20,873,650.00	$9,111,614.00
25. TOTAL Other Property and Investments	$22,035,988.00	$10,273,435.00
26. CURRENT AND ACCRUED ASSETS		
27. Cash (131)	$4,451,872.00	$2,729,674.00
28. Special Deposits (132-134)	$0.00	$0.00
29. Working Fund (135)	$19,790.00	$19,790.00
30. Temporary Cash Investments (136)	$5,476,948.00	$16,031,632.00
31. Notes Receivable (141)	$0.00	$0.00
32. Customer Accounts Receivable (142)	$108,131,455.00	$92,825,949.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
33. Other Accounts Receivable (143)	$10,133,997.00	$6,816,857.00
34. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$1,594,049.00	$1,184,712.00
35. Notes Receivable from Associated Companies (145)	$0.00	$0.00
6. Accounts Receivable from Assoc. Companies (146)	$97,209,024.00	$16,375,434.00
37. Fuel Stock (151)	$66,567,149.00	$71,040,238.00
38. Fuel Stock Expenses Undistributed (152)	$0.00	$0.00
39. Residuals (Elec) and Extracted Products (153)	$0.00	$0.00
40. Plant Materials and Operating Supplies (154)	$35,430,432.00	$32,048,293.00
41. Merchandise (155)	$0.00	$0.00
42. Other Materials and Supplies (156)	$0.00	$0.00
43. Nuclear Materials Held for Sale (157)	$0.00	$0.00
44. Allowances (158.1 and 158.2)	$6,329.00	$159.00
45. (Less) Noncurrent Portion of Allowances	$0.00	$0.00
46. Stores Expense Undistributed (163)	$6,352,862.00	$5,546,728.00
47. Gas Stored Underground - Current (164.1)	$54,151,379.00	$42,068,559.00
48. Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	$0.00	$0.00
49. Prepayments (165)	$7,636,886.00	$6,472,537.00
50. Advances for Gas (166-167)	$0.00	$0.00
51. Interest and Dividends Receivable (171)	$8,727.00	$2,497.00
52. Rents Receivable (172)	$781,782.00	$456,414.00
53. Accrued Utility Revenues (173)	$76,374,353.00	$67,041,506.00
54. Miscellaneous Current and Accrued Assets (174)	$0.00	$412.00
54.a Derivative Instrument Assets (175)	$0.00	$0.00
54.b Derivative Instrument Assets - Hedges (176)	$0.00	$0.00
55. TOTAL Current and Accrued Assets (Lines 27 - 54.b)	$471,138,936.00	$358,291,967.00
56. DEFERRED DEBITS		
57. Unamortized Debt Expenses (181)	$10,484,102.00	$13,519,246.00
58. Extraordinary Property Losses (181.1)	$0.00	$0.00
59. Unrecovered Plant and Regulatory Study Costs (182.2)	$0.00	$0.00
60. Other Regulatory Assets (182.3)	$413,300,917.00	$436,775,786.00
61. Prelim. Survey and Investigation Charges (Electric) (183)	$3,024,273.00	$4,012,217.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
62. Prelim. Sur. and Invest. Charges (Gas) (183.1,183.2)	$0.00	$0.00
63. Clearing Accounts (184)	$0.00	$0.00
64. Temporary Facilities (185)	$0.00	$0.00
65. Miscellaneous Deferred Debits (186)	$480,468,887.00	$458,589,969.00
66. Def. Losses from Disposition of Utility Plt. (187)	$0.00	$0.00
67. Research, Devel. and Demonstration Expend. (188)	$0.00	$26,435.00
68. Unamortized Loss on Reacquired Debt (189)	$18,031,262.00	$16,863,862.00
69. Accumulated Deferred Income Taxes (190)	$192,524,444.00	$286,542,027.00
70. Unrecovered Purchased Gas Costs (191)	$0.00	$0.00
71. TOTAL Deferred Debits (Lines 57-70)	$1,117,833,885.00	$1,216,329,542.00
72. Total Assets and other Debits (Total Lines 10-15,22,55,71)	$5,576,944,609.00	$6,092,383,920.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
1. PROPRIETARY CAPITAL		
2. Common Stock Issued (201)	$425,170,424.00	$425,170,424.00
3. Preferred Stock Issued (204)	$0.00	$0.00
4. Capital Stock Subscribed (202,205)	$0.00	$0.00
5. Stock Liability for Conversion (203,206)	$0.00	$0.00
6. Premium on Capital Stock (207)	$0.00	$0.00
7. Other Paid-in Capital Stock (208-211)	$1,521,167,368.00	$1,611,167,368.00
8. Installments Received on Capital stock (212)	$0.00	$0.00
9. (Less) Discount on Capital Stock (213)	$0.00	$0.00
10. (Less) Capital Stock Expense (214)	$835,889.00	$835,889.00
11. Retained Earnings (215,215.1,216)	$228,533,983.00	$294,897,774.00
12. Unappropriated Undistributed Subsidaiary Earnings (216.1)	$0.00	$0.00
13. (Less) Reacquired Capital Stock (217)	$0.00	$0.00
14. Accumulated Other Comprehensive Income (219)	$0.00	$0.00
15. TOTAL Proprietary Capital	$2,174,035,886.00	$2,330,399,677.00
16. LONG TERM DEBT		
17. Bonds (221)	$1,359,304,000.00	$1,659,304,000.00
18. (Less) Reacquired Bonds (222)	$0.00	$0.00
19. Advances from Associated Companies (223)	$0.00	$0.00
20. Other Long-Term Debt (224)	($1,681,852.00)	($1,590,554.00)
21. Unamortized Premium on Long-Term Debt (225)	$0.00	$0.00
22. (Less) Unamortized Discount on LongTerm Debt (226)	$4,560,414.00	$4,574,532.00
23. (Less) Current Portion of Long Term Debt	$0.00	$0.00
24. TOTAL Long Term Debt	$1,353,061,734.00	$1,653,138,914.00
25. OTHER NONCURRENT LIABILITIES		
26. Obligations Under Capital Leases-NonCurrent (227)	$0.00	$0.00
27. Accumulated Provision for Property Insurance (228.1)	$0.00	$0.00
28. Accumulated Provision for Injuries and Damages (228.2)	$4,272,805.00	$4,249,578.00
29. Accumulated Provision for Pensions and Benefits (228.3)	$142,374,775.00	$132,307,531.00
30. Accumulated Miscellaneous Operating Provisions (228.4)	$0.00	$0.00
31. Accumulated Provision for Rate Refunds (229)	$0.00	$0.00
32. Asset Retirement Obligations (230)	$85,375,725.00	$189,099,815.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
33. TOTAL OTHER Noncurrent Liabilities	$232,023,305.00	$325,656,924.00
34. CURRENT AND ACCRUED LIABILITIES		
35. Current Portion of Long-Term Debt	$0.00	$0.00
36. Notes Payable (231)	$263,956,483.00	$141,969,180.00
37. Accounts Payable (232)	$245,177,038.00	$172,152,826.00
38. Notes Payable to Associated Companies (233)	$0.00	$0.00
39. Account Payable to Associated Companies (234)	$20,016,016.00	$24,563,440.00
40. Customer Deposits (235)	$24,498,183.00	$25,405,488.00
41. Taxes Accrued (236)	$18,869,565.00	$19,925,519.00
42. Interest Accrued (237)	$5,870,903.00	$10,946,603.00
43. Dividends Declared (238)	$0.00	$0.00
44. Matured Long-Term Debt (239)	$0.00	$0.00
45. Matured Interests (240)	$0.00	$0.00
46. Tax Collections Payable (241)	$2,001,512.00	$1,516,387.00
47. Miscellaneous current and Accrued Liabilities (242)	$24,288,849.00	$21,396,264.00
48. Obligatons Under Capital Leases - Current (243)	$0.00	$0.00
49. Derivative Instrument Liabilities (244)	$47,988,828.00	$47,145,364.00
50. Derivative Instrument Liabilties - Hedges (245)	$33,263,681.00	$0.00
51. TOTAL Current and Accrued Liabilities	$685,931,058.00	$465,021,071.00
52. DEFERRED CREDITS		
53. Customer Advances for Construction (252)	$8,234,051.00	$7,428,646.00
54. Accumulated Deferred Investment Tax Credits (255)	$35,982,105.00	$34,643,471.00
55. Deferred Gains from Disposition of Utility Plant (256)	$0.00	$0.00
56. Other Deferred Credits (253)	$14,776,604.00	$4,017,629.00
57. Other Regulatory Liabilities (254)	$180,068,801.00	$156,432,731.00
58. Unamortized gain on Reacquired Debt (257)	$0.00	$0.00
59. Accumulated Deferred Income Taxes (281-283)	$892,831,065.00	$1,115,644,857.00
60. TOTAL Deferred Credits	$1,131,892,626.00	$1,318,167,334.00
61. TOTAL Liabilities and Other Credits (Total Lines 15,24,33,51 and 60)	$5,576,944,609.00	$6,092,383,920.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Balance Sheet - Liabilities and Other Credits (Ref Page: 112) - NOTES

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Income for the Year (Ref Page: 114)

	Total (c)	Total - Prev Yr (d)	Electric (e)	Gas (g)	Other (i)
1..UTILITY OPERATING INCOME					
2. Gas Operating Revenues (400)	$1,465,598,747.00	$1,537,927,386.00	$1,146,077,403.00	$319,521,344.00	$0.00
3. Operating Expenses					
4. Operation Expenses (401)	$790,731,677.00	$911,715,538.00	$595,450,826.00	$195,280,851.00	$0.00
5. Maintenance Expenses (402)	$114,048,758.00	$111,790,202.00	$94,604,630.00	$19,444,128.00	$0.00
6. Depreciation Expense (403)	$151,308,951.00	$147,126,109.00	$122,203,833.00	$29,105,118.00	$0.00
7. Depreciation Expense for Asset Retirement Costs (403.1)	$0.00	$0.00	$0.00	$0.00	$0.00
8. Amort and Depl of Utility Plant (404-405)	$10,664,307.00	$9,488,709.00	$7,464,986.00	$3,199,321.00	$0.00
9. Amort of Utility Plant Acq. Adj (406)	$0.00	$0.00	$0.00	$0.00	$0.00
10. Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407.1)	$0.00	$0.00	$0.00	$0.00	$0.00
11. Amort. of Conversion Expenses (407.2)	$0.00	$0.00	$0.00	$0.00	$0.00
12. Regulatory Debits (407.3)	$0.00	$0.00	$0.00	$0.00	$0.00
13. (Less) Regulatory Credits (407.4)	$0.00	$0.00	$0.00	$0.00	$0.00
14. Taxes Other than Income Taxes (408.1)	$37,400,047.00	$34,200,411.00	$28,340,155.00	$9,059,892.00	$0.00
15. Income Taxes - Federal (409.1)	($13,679,235.00)	($24,215,205.00)	($12,314,375.00)	($1,364,860.00)	$0.00
16. Income Taxes - Other (409.1)	$3,659,700.00	$9,909,706.00	$1,867,677.00	$1,792,023.00	$0.00
17. Provision for Deferred Income Taxes (410.1)	$447,741,617.00	$298,118,539.00	$366,455,672.00	$81,285,945.00	$0.00
18. (Less) Provision for Deferred Income Taxes (411.1)	$320,258,358.00	$178,198,376.00	$259,277,427.00	$60,980,931.00	$0.00
19. Investment Tax Credit Adj. - Net (411.4)	($1,338,634.00)	($1,788,780.00)	($1,260,914.00)	($77,720.00)	$0.00
20. (Less) Gains from Disp. of Utility Plant (411.6)	$0.00	$0.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Income for the Year (Ref Page: 114)

	Total (c)	Total - Prev Yr (d)	Electric (e)	Gas (g)	Other (i)
21. Losses from Disp. of Utility Plant (411.7)	$0.00	$0.00	$0.00	$0.00	$0.00
22. (Less) Gains from Disposition of Allowances (411.8)	$122.00	$427.00	$122.00	$0.00	$0.00
23. Losses from Disposition of Allowances (411.9)	$0.00	$0.00	$0.00	$0.00	$0.00
24. Accretion Expense (411.10)	$0.00	$0.00	$0.00	$0.00	$0.00
25. Total Utility Operating Expenses (Enter Total of Lines 4 - 22)	$1,220,278,708.00	$1,318,146,426.00	$943,534,941.00	$276,743,767.00	$0.00
26. Net Utility Operating Income (Line 2 less line 23 - Carry forward to pg 117 line 25)	$245,320,039.00	$219,780,960.00	$202,542,462.00	$42,777,577.00	$0.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Income (continued) (Ref Page: 116)

	Current Year	Previous Year
27. Net Utility Operating Income (Carried from pg 114)	$245,320,039.00	$219,780,960.00
28. Other Income and Deductions		
29. Other Income		
30. Nonutility Operating Income		
31. Revenues From Merchandising, Jobbing and Contract Work (415)	$6,285.00	$39,286.00
32. (Less) Costs and Exp. of Merchandising,Job. and Contract Work (416)	$2,207.00	$6,842.00
33. Revenues From Nonutility Operations (417)	$1,393,587.00	$1,429,857.00
34. (Less) Expenses of Nonutility Operations (417.1)	$0.00	$0.00
35. Nonoperating Rental Income (418)	$0.00	$0.00
36. Equity in Earnings of Subsidiary Companies (418.1)	$0.00	$0.00
37. Interest and Dividend Income (419)	$68,155.00	$44,207.00
38. Allowance for Other Funds Used During Construction (419.1)	$0.00	$0.00
39. Miscellaneous Nonoperating Income (421)	($9,045.00)	($4,390.00)
40. Gain on Disposition of Property (421.1)	$165,839.00	$6,852.00
41. TOTAL Other Income	$1,622,614.00	$1,508,970.00
42. Other Income Deductions		
43. Loss on Disposition of Property (421.2)	$15,141.00	$217,416.00
44. Miscellaneous Amortization (425)	$0.00	$0.00
45. Miscellaneous Income Deductions (426.1 - 426.5)	$7,000,464.00	$5,079,208.00
46.TOTAL Other Income Deductions	$7,015,605.00	$5,296,624.00
47. Taxes Applic. to Other Income and Deductions		
48. Taxes Other Than Income Taxes (408.2)	$7,003.00	$6,710.00
49. Income Taxes - Federal (409.2)	($1,834,650.00)	($1,079,880.00)
50. Income Taxes - Other (409.2)	($334,587.00)	($196,938.00)
51. Provision for Deferred Inc. Taxes (410.2)	$230,967.00	$1,257.00
52. (Less) Provision for Deferred Income Taxes CR (411.2)	$42,045.00	$24,548.00
53. Investment Tax Credit Adj. Net (411.5)	$0.00	
54. (Less) Investment Tax Credits (420)	$0.00	
55. TOTAL Taxes on Other Income and Deduct.	($1,973,312.00)	($1,293,399.00)
56. Net Other Income and Deductions (Lines 39,44,53)	($3,419,679.00)	($2,494,255.00)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Income (continued) (Ref Page: 116)

	Current Year	Previous Year
57. Interest Charges		
58. Interest on Long Term Debt (427)	$50,809,850.00	$44,283,072.00
59. Amort of Debt Disc. and Expense (428)	$2,470,268.00	$2,310,317.00
60. Amortization of Loss on Reacquired Debt (428.1)	$1,167,401.00	$1,106,947.00
61. (Less) Amort. of Premium on Debt - CR (429)	$0.00	$0.00
62. (Less) Amortization of Gain on Reacquired Debt - CR (429.1)	$0.00	$0.00
63. Interest on Debt to Assoc. Companies (430)	$5,661.00	$5,761.00
64. Other Interest Expense (431)	$2,083,390.00	$1,504,616.00
65. (Less) Allowance for Borrowed Funds Used During Construction CR (432)	$0.00	$0.00
66. Net Interest Charges	$56,536,570.00	$49,210,713.00
67. Income Before Extraordinay Items (Lines 25,54 and 64)	$185,363,790.00	$168,075,992.00
68. Extraordinary Items		
69. Extraordinary Income (434)	$0.00	$0.00
70. (Less) Extraordinary Deductions (435)	$0.00	$0.00
71. Net Extraordinary Items (Lines 67 less 68)	$0.00	$0.00
72. Income Taxes - Federal and Other (409.3)	$0.00	$0.00
73. Extraordinary Items After Taxes (Lines 69 less 70)	$0.00	$0.00
74. Net Income (Lines 67 and 73)	$185,363,790.00	$168,075,992.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Retained Earnings for the Year (Ref Page: 118)

Item (a)		Acct (b)	Amount (c)
UNAPPROPRIATED RETAINED EARNINGS (216)			
State balance and purpose of each appropriated retained earnings amount at end of year and			
1. Balance - Beginning of the Year			$228,533,983.00
Changes (Identify by prescribed retained earnings accounts)			
give accounting entries for any applications of appropriated retained earnings during the year.			
Adjustments to Retained Earnings (439)			
Credit:	Rounding	0	$1.00
4. TOTAL Credits to Retained Earnings (439)			$1.00
Debit:			
5. TOTAL Debits to Retained Earnings (439)			
6. Balance Transferred from Income (433 less 418.1)		0	$185,363,790.00
Appropriations of Retained Earnings (436)			
8. TOTAL appropriations of Retained Earnings (436)			
Dividends Declared - Preferred stock (437)			
10. TOTAL Dividends Declared - Preferred Stock (437)			
Dividends Declared - Common Stock (438)			
	0	Without Par Value	($119,000,000.00)
12. TOTAL Dividends Declared - Common Stock (438)			($119,000,000.00)
13. Transfers from Acct 216.1, Unappropriated Undistributed Subsidary Earnings			
14. Balance End of Year (Total Lines 1,4,5,6,8,10,12,13)			$294,897,774.00
APPROPRIATED RETAINED EARNINGS (215)			
(215)			
16. TOTAL Appropriated Retained Earnings (215)			

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Retained Earnings for the Year (Ref Page: 118)

Item (a)	Acct (b)	Amount (c)
APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL		
17.TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (215.1)		
18. TOTAL Appropriated Retained Earnings (total lines 16 and 17) (214,215.1)		
19. TOTAL Retained Earnings (Lines 14 and 18) (215, 215.1, 216)		$294,897,774.00
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (216.1)		
20. Balance - Beginning of Year (Debit or Credit)		
21. Equity in Earnings for Year (Credit) (418.1)		
22. (Less) Dividends Received (Debit)		
23. Other Charges (explain)		
24. Balance - End of Year		

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Cash Flows (Ref Page: 120)

	Description	Amounts
1. Net Cash Flow From Operating Activities:		
2. Net Income (Line 72 c on page 117)		$185,363,790.00
3. Noncash Charges (Credits) to Income:		
4. Depreciation and Depletion		$151,308,951.00
Amortization of (Specifiy)		
5.	Plant	$10,664,307.00
6. Deferred Income Taxes (Net)		$128,831,722.00
7. Investment Tax Credit Adjustment (Net)		($1,338,634.00)
8. Net (Increase) Decrease in Receivables		$106,245,846.00
9. Net (Increase) Decrease in Inventory		$3,632,318.00
10. Net (Increase) Decrease in Allowances Inventory		$6,170.00
11. Net Increase (Decrease) in Payables and Acccrued Expenses		$2,314,964.00
12. Net (Increase) Decrease in Other Regulatory Assets		($23,792,799.00)
13. Net Increase (Decrease) in Other Regulatory Liabilities		$62,071.00
14. (Less) Allowance for Other Funds Used During Construction		$0.00
15. (Less) Undistributed Earnings from Subsidiary Companies		$0.00
Other:		
16.	Other (See FERC Form 1 Footnotes):	$35,291,004.00
16.	Change in Other Deferred Debits	$231,892.00
16.	Change in Other Deferred Credits	($874,256.00)
16.	Interest Rate Swaps Settlement	($43,688,302.00)
17. Net Cash Provided by (Used in) Operating Activities (Total lines 2 thru 16)		$554,259,044.00
Cash Flows from Investment Activities:		
21. Construction and Acquisition of Plant (Including Land):		
22. Gross Additions to Utility Plant (Less nuclear fuel)		($647,110,962.00)
23. Gross Additions to Nuclear Fuel		$0.00
24. Gross Additions to Common Utility Plant		($20,729,273.00)
25. Gross Additons to Nonutility Plant		$0.00
26. (Less) Allowance for Other Funds Used During Construction		$0.00
Other		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Cash Flows (Ref Page: 120)

Description		Amounts
27.	Other (See FERC Form 1 Footnotes):	($21,411,936.00)
Cash Outflows for Plant (Total lines 22-27)		($689,252,171.00)
30. Acquisition of Other Noncurrent Assets (d)		$0.00
31. Proceeds from Disposal of Noncurrent Assets (d)		$194,454.00
32. Retirements of Property,Plant and Equipment		$0.00
33. Investments in and Advances to Assoc. and Subsidary Companies		$0.00
34. Contributions and Advances from Assoc. and Subsidiary Companies		$0.00
35. Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		$0.00
37. Purchase of Investment Securities (a)		$0.00
38. Proceeds from Sales of Investment Securities (a)		$0.00
40. Loans Made or Purchased		$0.00
41. Collections on Loans		$0.00
43. Net (Increase) Decrease in Receivables		$0.00
44. Net (Increase) Decrease in Inventory		$0.00
45. Net (Increase) Decrease in Allowances Held for Speculation		$0.00
46. Net Increase (Decrease) in Payables and Accrued Expenses		$0.00
Other:		
47.	0	$0.00
48. Net Cash Provided by (used in) investing Activities (Lines 28-47)		($689,057,717.00)
Cash Flows from Financing Activities:		
52. Proceeds from Issuance of:		
53. Long - Term Debt (b)		$294,631,159.00
54. Preferred Stock		$0.00
55. Common Stock		$0.00
Other		
56		
57. Net Increase in Short-Term Debt (c)		$0.00
Other		
58.		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Statement of Cash Flows (Ref Page: 120)

Description		Amounts
59. Cash Provided by Outside Sources (Total lines 53-58)		$294,631,159.00
61. Payments for Retirement of		
62. Long-Term Debt (b)		
63. Preferred Stock		
64. Common Stock		
Other		
65.	LG&E and KU Energy LLC Equity Contribution	$90,000,000.00
66. Net Decrease in Short-Term Debt (c)		($122,000,000.00)
68. Dividends on Preferred Stock		
69. Dividends on Common Stock		($119,000,000.00)
70. Net Cash Provided by (used in) Financing Activities (Lines 59-69)		$143,631,159.00
Net Increase (Decrease) in Cash and Cash Equivalents (Total Lines 18,49,71)		$8,832,486.00
Cash and Cash Equivalents at Beginning of Year		$9,948,610.00
Cash and Cash Equivalents at End of Year		$18,781,096.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	Total (b)	Electric (c)	Gas (d)	Other (Total)	Common (h)
Utility Plant					
In Service					
3. Plant in Service (Classified)	$4,959,059,890.00	$3,748,677,590.00	$966,619,554.00	$0.00	$243,762,746.00
4. Property under Capital Leases					
5. Plant Purchased or Sold					
6. Completed Construction not Classified	$1,166,512,766.00	$1,089,788,464.00	$54,543,523.00	$0.00	$22,180,779.00
7. Experimental Plant Unclassifed					
8. Total - Utility Plant (Lines 3-7)	$6,125,572,656.00	$4,838,466,054.00	$1,021,163,077.00	$0.00	$265,943,525.00
9. Leased to Others					
10. Held for Future Use	$5,867,294.00	$5,867,294.00	$0.00	$0.00	$0.00
11. Construction Work in Progress	$389,846,496.00	$357,132,814.00	$22,415,538.00	$0.00	$10,298,144.00
12. Acquisition Adjustments					
13. Total Utility Plant (Lines 8 - 12)	$6,521,286,446.00	$5,201,466,162.00	$1,043,578,615.00	$0.00	$276,241,669.00
14. Accum. Prov. for Depr, Amort, And Depl.	$2,015,937,460.00	$1,589,336,934.00	$288,205,717.00	$0.00	$138,394,809.00
15. Net Utility Plant (Line 13 less 14)	$4,505,348,986.00	$3,612,129,228.00	$755,372,898.00	$0.00	$137,846,860.00
16. Detail of Accumulated Provisions for Depreciation Amortization and Depletion					
17. In Service					
18. Depreciation	$1,968,602,653.00	$1,589,215,749.00	$288,205,594.00	$0.00	$91,181,310.00
19. Amort. and Depl. of Production Natural Gas Land and Land Rights					
20. Amort of Underground Storage Land and Land Rights	$123.00	$0.00	$123.00	$0.00	$0.00
21. Amort of Other Utility Plant	$47,213,499.00	$0.00	$0.00	$0.00	$47,213,499.00
22. Total In Service (Lines 18-21)	$2,015,816,275.00	$1,589,215,749.00	$288,205,717.00	$0.00	$138,394,809.00
23. Leased to Others					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	Total (b)	Electric (c)	Gas (d)	Other (Total)	Common (h)
24. Depreciation					
25. Amortization and Depletion					
26. Total Leased to Others (Lines 24 and 25)					
27. Held for Future Use					
28. Depreciation	$121,185.00	$121,185.00	$0.00	$0.00	$0.00
29. Amortization					
30. Total Held for Future Use (Lines 28 and 29)	$121,185.00	$121,185.00	$0.00	$0.00	$0.00
31. Abandonment of Leases (Naturual Gas)					
32. Amort. Of Plant Aquision Adj.					
33. Total Accumulated Provisions (Should agree with Line 14, Total 22,26,30,31 and 32)	$2,015,937,460.00	$1,589,336,934.00	$288,205,717.00	$0.00	$138,394,809.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
INTANGIBLE PLANT						
2. Organization (301)	$0.00					
3. Franchises and Consents (302)	$387.00	$0.00	$0.00	$0.00	$0.00	$387.00
4. Miscellaneous Intangible Plant (303)	$0.00					
5. Total Intangible Plant	$387.00	$0.00	$0.00	$0.00	$0.00	$387.00
PRODUCTION PLANT						
7. Natural Gas Production and Gathering Plant						
8. Producing Lands (325.1)						
9. Producing Leaseholds (325.2)						
10. Gas Rights (325.3)						
11. Rights of Way (325.4)						
12. Other Land and Land Rights (325.5)						
13. Gas Well Structures (326)						
14. Field Compressor Station Structures (327)						
15. Field Measuring and Regulating Station Equipment (328)						
16. Other Structures (329)						
17. Producing Gas Wells - Well Construction (330)						
18. Producing Gas Wells - Well Equipment (331)						
19. Field Lines (332)						
20. Field Compressor Station Equipment (333)						
21. Field Measuring and Regulating Station Equipment (334)						
22. Drillnig and Cleaning Equipment (335)						

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
23. Purification Equipment (336)						
24. Other Equipment (337)						
25. Unsuccessful Exploration and Development Costs (338)						
26. Asset Retirement Costs for Natural Gas Production and Gathering Plant (339)						
27. Total Production and Gathering Plant						
28. PRODUCTS EXTRACTION PLANT						
29. Land and Land Rights (340)						
30. Structures and Improvements (341)						
31. Extraction and Refining Equipment (342)						
32. Pipe Lines (343)						
33. Extracted Products Storage Equipment (344)						
34. Compressor Equipment (345)						
35. Gas Measuring and Regulating Equipment (346)						
36. Other Equipment (347)						
37. Asset Retirement Costs for Products Extraction Plant (348)						
38. Total Products Extraction Plant						
39. Total Natural Gas Production Plant (Lines 27 and 38)						
40. Manufactured Gas Production Plant						

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
41. Total Production Plant (Lines 39 and 40)						

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
NATURAL GAS STORAGE AND PROCESSING PLANT						
Underground Storage Plant						
44. Land (350.1)	$32,865.00	$0.00	$0.00	$0.00	$0.00	$32,865.00
45. Rights-of-Way (350.2)	$104,869.00	$0.00	$0.00	$0.00	$0.00	$104,869.00
46. Structures and Improvements (351)	$10,306,983.00	$4,312,311.00	($7,544.00)	$0.00	$0.00	$14,611,750.00
47. Wells (352)	$19,511,960.00	$394,861.00	($505,722.00)	$0.00	($244,139.00)	$19,156,960.00
48. Storage Leaseholds and Rights (352.1)	$548,241.00	$0.00	$0.00	$0.00	$0.00	$548,241.00
49. Reservoirs (352.2)	$400,511.00	$0.00	$0.00	$0.00	$0.00	$400,511.00
50. Non-recoverable Natural Gas (352.3)	$9,648,855.00	$0.00	$0.00	$0.00	$0.00	$9,648,855.00
51. Lines (353)	$20,169,952.00	$1,130,657.00	($24,531.00)	$0.00	$0.00	$21,276,078.00
52. Compressor Station Equipment (354)	$48,745,833.00	($2,432,246.00)	($43,150.00)	$0.00	($324,663.00)	$45,945,774.00
53. Measuring and Regulating Equipment (355)	$741,596.00	$7,839.00	$0.00	$0.00	$0.00	$749,435.00
54. Purification Equipment (356)	$15,286,862.00	$3,581,776.00	($32,233.00)	$0.00	$0.00	$18,836,405.00
55. Other Equipment (357)	$2,529,478.00	$62,897.00	($7,067.00)	$0.00	$568,802.00	$3,154,110.00
56. Asset Retirement Costs for Underground Storage Plant (358)	$4,282,210.00	$456,123.00	($248,316.00)	$0.00	$0.00	$4,490,017.00
57. Total Underground Storage Plant	$132,310,215.00	$7,514,218.00	($868,563.00)	$0.00	$0.00	$138,955,870.00
Other Storage Plant						
59. Land and Land Rights (360)						
60. Structures and Imporvements (361)						
61. Gas Holders (362)						
62. Purification Equipment (363)						

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
63. Liquefaction Equipment (363.1)						
64. Vaporaizing Equipment (363.2)						
65. Compressor Equipment (363.3)						
66. Measuring and Regulating equipment (363.4)						
67. Other Equipment (363.5)						
68. Asset Retirement Costs for Other Storage Plant (363.6)						
69. Total Other storage Plant						
70. Base Load Liquefied natural Gas Terminaling and Processing Plant						
71. Land and Land Rights (364.1)						
72. Structures and Improvements (364.2)						
73. LNG Processing Terminal Equipments (364.3)						
74. LNG Transportation Equipment (364.4)						
75. Measuring and Regulating Equipment (364.5)						
76. Compressor Station Equipment (364.6)						
77. Communications Equipment (364.7)						
78. Other Equipment (364.8)						
79. Asset Retirement Costs for Base Load Liquefied Natual Gas Terminaliing and Processing Plant (364.9)						

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
80. Total Base Load Liquefied Nat`l Gas, Terminal and Processing Plant						
76. Total Nat`l Gas Storage and Processing Plant (57,69,80)	$132,310,215.00	$7,514,218.00	($868,563.00)	$0.00	$0.00	$138,955,870.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
TRANSMISSION PLANT						
83. Land and Land Rights (365.1)						
84. Rights-of-Way (365.2)	$220,660.00	$0.00	$0.00	$0.00	$0.00	$220,660.00
85. Structures and Improvements (366)						
86. Mains (367)	$44,291,412.00	$6,291,542.00	($362,789.00)	$0.00	$0.00	$50,220,165.00
87. Compressor Station Equipment (368)						
88. Measuring and Regulating Sstation Equipment (369)						
89. Communication Equipment (370)						
90. Other Equipment (371)						
91. Asset Retirement Costs for Transmission Plant (372)	$3,871,893.00	$0.00	($41,150.00)	($1,498,737.00)	$0.00	$2,332,006.00
92. Total Transmission Plant	$48,383,965.00	$6,291,542.00	($403,939.00)	($1,498,737.00)	$0.00	$52,772,831.00
DISTRIBUTION PLANT ( )						
94. Land and Land Rights (374)	$133,742.00	$0.00	($127.00)	$0.00	$881.00	$134,496.00
95. Structures and Improvements (375)	$911,565.00	$267,179.00	($33,752.00)	$0.00	$0.00	$1,144,992.00
96. Mains (376)	$366,261,684.00	$15,014,972.00	($291,983.00)	$0.00	$0.00	$380,984,673.00
97. Compressor Station Equipment (377)						
98. Measuring and Regulating Station Equipment - General (378)	$15,108,848.00	$2,636,087.00	($68,553.00)	$0.00	$0.00	$17,676,382.00
99. Measuring and Regulating Station Equipment - City Gate (379)	$5,885,444.00	$1,686,593.00	($386,646.00)	$0.00	$0.00	$7,185,391.00
100. Services (380)	$284,207,737.00	$46,656,886.00	($4,016,408.00)	$0.00	$0.00	$326,848,215.00
101. Meters (381)	$45,721,892.00	$2,373,169.00	($744,043.00)	$0.00	$0.00	$47,351,018.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
102. Meter Installations (382)						
103. House Regulators (383)	$25,413,373.00	$516,132.00	($379,125.00)	$0.00	$0.00	$25,550,380.00
104. House Regulator Installations (384)						
105. Industrial Measuring and Regulating Station Equipment (385)	$944,325.00	$16,362.00	$0.00	$0.00	$0.00	$960,687.00
106. Other Property on Customers Premises (386)						
107. Other Equipment (387)	$51,112.00	$0.00	$0.00	$0.00	$0.00	$51,112.00
108. Asset Retirement Costs for Distribution Plant (388)	$11,862,067.00	$0.00	($286,699.00)	($1,093,275.00)	$0.00	$10,482,093.00
109. Total Distribution Plant	$756,501,789.00	$69,167,380.00	($6,207,336.00)	($1,093,275.00)	$881.00	$818,369,439.00
GENERAL PLANT						
111. Land and Land Rights (389)						
112. Structures and Improvements (390)						
113. Office Furniture and Equipment (391)						
114. Transportation Equipment (392)	$1,878,027.00	$64,881.00	($384,514.00)	$0.00	($41,622.00)	$1,516,772.00
115. Stores Equipment (393)						
116. Tools, Shop and garage Equipment (394)	$5,910,717.00	$491,208.00	$0.00	$0.00	$0.00	$6,401,925.00
117. Laboratory Equipment (395)						
118. Power Operated Equipment (396)	$3,186,019.00	$0.00	($81,787.00)	$0.00	$41,622.00	$3,145,854.00
119. Communication Equipment (397)	$17,080.00	($17,080.00)	$0.00	$0.00	$0.00	$0.00
120. Miscellaneous equipment (398)						

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Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
121. Subtotal (Lines 104-113)	$10,991,843.00	$539,009.00	($466,301.00)	$0.00	$0.00	$11,064,551.00
122. Other Tangible Property (399)						
123. Asset Retirement Costs for General Plant (399.1)						
124. Total General Plant (Lines 121,122 and 123)	$10,991,843.00	$539,009.00	($466,301.00)	$0.00	$0.00	$11,064,551.00
125. Total Accounts 101 and 106	$948,188,199.00	$83,512,149.00	($7,946,140.00)	($2,592,012.00)	$881.00	$1,021,163,077.00
126. Gas Plant Purchased						
127. (Less) Gas Plant Sold						
128. Experimental Gas Plant Unclassified						
Total Gas Plant in Service (Lines 125-128)	$948,188,199.00	$83,512,149.00	($7,946,140.00)	($2,592,012.00)	$881.00	$1,021,163,077.00

Note:
Page 206, Line 52, column c:
Amounts temporarily classified to plant account Compressor Station Equipment (354) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Page 206, Line 91, column e:
Adjustment due to changes in asset retirement cost estimates.

Page 206, Line 108, column e:
Adjustment due to changes in asset retirement cost estimates.

Page 206, Line 119, column c:
Amounts temporarily classified to plant account Communication Equipment (397) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

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Gas Property and Capacity Leased From Others (Ref Page: 212)

	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments For Current Year
Total				

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Gas Plant Held for Future Use (Acct 105) (Ref Page: 214)

	Description	Date Orig. Included (b)	Date Exp. to Use (c)	Balance (d)
TOTAL				

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Construction Work in Progress - (Acct 107) (Ref Page: 216)

	Project (a)	Construction WIP (b)	Est Add Cost
	GAS STORAGE MAJOR	$0.00	$0.00
	MAGNOLIA HYDROGEN SULFIDE TREATMENT ENHANCEMENT	$1,246,933.00	$153,067.00
	MULDRAUGH EQUIPMENT REPLACEMENT	$1,397,671.00	$0.00
	GAS STORAGE MINOR	$9,203,599.00	$2,001,150.00
	0	$0.00	$0.00
	GAS TRANSMISSION MINOR	$1,642,767.00	$565,456.00
	0	$0.00	$0.00
	GAS DISTRIBUTION MAJOR	$0.00	$0.00
	BARDSTOWN RD CITY GATE STATION EQUIPMENT UPGRADE	$1,727,931.00	$1,936,069.00
	RELOCATE PIPELINE FOR KY HWY 22 ROAD WORK	$1,868,292.00	$15,708.00
	GAS DISTRIBUTION MINOR	$5,023,189.00	$2,892,996.00
	0	$0.00	$0.00
	GAS GENERAL PLANT MINOR	$305,156.00	$13,838.00
TOTAL		$22,415,538.00	$7,578,284.00

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General Description of Construction Overhead Procedure - Components of Formulat (Ref Page: 218)

	Amount (b)	Capitalization Ration (Percent) (c)	Cost Rate Percentage (d)
Please include all notes requested for construction overhead with the hard copy.			
Uppercase Vars (S,D,P,C,W) fall under Amount (b) column			
Lowercase Vars (s,d,p,c) fall under Cost Rate Percentage (d) column			
1. Components of Formula (Derived from actual book balances and actual cost rates)			
Average Short-Term Debt (Var S)			
Short-Term Interest (Var s)			
Long Term Debt (Vars D and d)			
Preferred Stock (Vars P and p)			
Common Equity (Vars C and c)			
Total Capitalization			
Average Construction Work in Progress Balance (Var W)			
2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C))(1-(S/W)]			
3. Rate for Other Funds [1-(S/W)][p(P/D+P+C)) + c(C/(D+P+C))]			
4. Weighted Average Rate Actually Used for the Year:			
a. Rate for Borrowed Funds			
b. Rate for Other Funds			

LOCAL ENGINEERING:

Salaries and expenses of Gas Distribution Operations personnel engaged in construction work, but not assignable to a particular capital project, are charged to engineering clearing projects. Examples of such charges are: work with the construction budget, cost of estimating, construction work, preparation of field reports, conferences on construction matters, and general supervision of construction projects.

Each month, the costs accumulated in these clearing projects are allocated to specific capital projects owned by Gas Distribution based on the monthly spend by project.
The labor and expenses of engineers and other personnel who are directly assigned to a particular capital project are charged to that project.

SERVICE CONTRACT CHARGES:

These expenses are charged directly to construction and other projects based on service performed.

EMPLOYEE BENEFITS:

Vacation, holiday, sick and other off-duty payments, medical, dental, group life insurance, long-term disability, 401(k), retirement income account and pension costs, are charged to construction by applying overhead rates to direct labor.

ADMINISTRATIVE AND GENERAL EXPENSES:

The allocation of administrative and general expenses to construction is based on a study of the estimated time engaged in construction activities by persons and departments charging time to FERC Account 920. The administrative and general salaries and expenses (FERC Account 920-921) applicable to construction are allocated to all construction projects on the basis of total direct costs.

Note:

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC):

LG&E does not capitalize AFUDC for gas utility plant.

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Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

	Description	Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
A. BALANCES AND CHANGES DURING YEAR					
Balance beginning of Year		$272,699,356.00	$272,699,356.00	$0.00	$0.00
Depreciation Provisions for Year, Charged to					
Depreciation Expense (403)		$25,516,575.00	$25,516,575.00	$0.00	$0.00
Depreciation Expense for Asset Retirement Costs (403.1)					
Expense of Gas Plant Leased to Others (413)					
Transportation Expenses - Clearing		$221,605.00	$221,605.00	$0.00	$0.00
Other Clearing Accounts					
Other Clearing (Specify)					
Total Deprec. Prov. for Year		$25,738,180.00	$25,738,180.00	$0.00	$0.00
Net Charges for Plant Retired					
Book Cost of Plant Retired		$7,946,139.00	$7,946,140.00	$0.00	$0.00
Cost of Removal		$3,274,677.00	$3,274,676.00	$0.00	$0.00
Salvage (Credit)		$69,087.00	$69,087.00	$0.00	$0.00
Total Net Chrgs for Plant Ret		$11,151,729.00	$11,151,729.00	$0.00	$0.00
Other Debit or Credit Items (Describe)					
	Accrual for Depreciation on Asset Retirement costs	$922,488.00	$922,488.00	$0.00	$0.00
	Customer Payments related to Construction Projects	($2,701.00)	($2,701.00)	$0.00	$0.00
Balance at End of Year		$288,205,594.00	$288,205,594.00	$0.00	$0.00
B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS					
Productions - Manufactured Gas					
Prodcution of Gathering-Natural Gas					
Products Extraction - Natural Gas					

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Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

Description	Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
Underground Gas Storage	$36,155,960.00	$36,155,960.00	$0.00	$0.00
Other Storage Plant				
Base Load LNG Terminaling and Processing Plant				
Transmision	$11,556,814.00	$11,556,814.00	$0.00	$0.00
Distribution	$234,891,570.00	$234,891,570.00	$0.00	$0.00
General	$5,601,250.00	$5,601,250.00	$0.00	$0.00
Total	$288,205,594.00	$288,205,594.00	$0.00	$0.00

Note:

Accrual for depreciation on asset retirement costs (Other Regulatory Assets FERC 182.3)	$ 922,488
Customer payments related to construction projects	(2,701)

	$ 919,787

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Gas Stored Accounts (Lines 1-5) (Ref Page: 220)

	117.1 (b)	117.2 (c)	117.3 (d)	117.4 (e)	164.1 (f)	164.2 (g)	164.3 (h)	Total (I)
Balance at Beginning of Year	$2,139,990.00	$0.00	$0.00	$0.00	$54,151,379.00	$0.00	$0.00	$56,291,369.00
Gas delivered to Storage	$0.00	$0.00	$0.00	$0.00	$38,769,827.00	$0.00	$0.00	$38,769,827.00
Gas Withdrawn from Storage	$0.00	$0.00	$0.00	$0.00	$50,852,645.00	$0.00	$0.00	$50,852,646.00
Other Debits and Credits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Balance at End of Year	$2,139,990.00	$0.00	$0.00	$0.00	$42,068,559.00	$0.00	$0.00	$44,208,550.00

Note:
Gas Withdrawn from Storage, Column (f) includes $1,690,061 for 427,223 Mcf of gas lost in storage operations charged to Gas Losses (823).

Non-current gas in Column (b) consists of recoverable base gas. Current gas in Column (f) consists of working gas.

The weighted average cost inventory method is used to report gas stored underground.

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Gas Stored Accounts (Lines 6-7) (Ref Page: 220)

	117.1 (b)	117.2 (c)	117.3 (d)	117.4 (e)	164.1 (f)	164.2 (g)	164.3 (h)	Total (I)
MCF	$2,930,000.00	$0.00	$0.00	$0.00	$12,333,765.00	$0.00	$0.00	$15,263,765.00
Amount Per MCF	$0.73	$0.00	$0.00	$0.00	$3.41	$0.00	$0.00	$2.90

Note:
Amounts in row MCF are statistical amounts and not dollars as shown.

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Investments (123,124,136) (Ref Page: 222)

	Description of Investment (a)	(b)	Book Cost at Beginning of	Purchases or Additions (d)	Sales of Other Dispositions
Investments in Associated Companies (123)					
(123)					
Other Investments (124)					
(124)					
Temporary Case Investments (136)					
(136)	Goldman Sachs Financial Square Fed		$7.00	$0.00	$7.00
(136)	Goldman Sachs Financial Sqaure Fed		$201.00	$0.00	$201.00
(136)	JP Morgan Fund		$1,949,947.00	$25,776,000.00	$27,726,148.00
(136)	Fidelity Fund		$1,677,230.00	$182,048,800.00	$183,732,298.00
(136)	UBS Fund		$1,849,571.00	$116,153,000.00	$118,004,442.00
(136)	Black Rock Temp Fund		$0.00	$26,708,000.00	$26,708,365.00
(136)	Deutsche Money Mkt Series		$0.00	$53,040,000.00	$53,042,171.00
(136)	Dreyfus Instl Cash Advantage		$0.00	$19,643,200.00	$19,643,274.00
(136)	Federated Prime Cash Oblig		$0.00	$47,000,000.00	$47,000,470.00
(136)	Goldman FSQ Money Market		$0.00	$61,321,000.00	$61,326,326.00
(136)	Invesco Liquid Assets		$0.00	$43,836,000.00	$43,842,254.00
(136)	WAM Instit Cash Resrvs		$0.00	$84,187,000.00	$68,152,400.00
(136)	Wells Fargo Adv Heritage		$0.00	$56,900,000.00	$56,905,259.00
(136)	SunTrust Bank		$0.00	$24,900,000.00	$24,907,847.00
(136)			$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Investments (123,124,136) (Ref Page: 222) (Part Two)

	Description of Investment (a)	Principal Amt or No of	Book Cost End of Year (g)	Revenues for Year (h)	Gain or Loss (i)
Investments in Associated Companies (123)					
(123)					
Other Investments (124)					
(124)					
Temporary Case Investments (136)					
(136)	Goldman Sachs Financial Square Fed	$0.00	$0.00	$0.00	$0.00
(136)	Goldman Sachs Financial Sqaure Fed	$0.00	$0.00	$0.00	$0.00
(136)	JP Morgan Fund	$0.00	$0.00	$201.00	$0.00
(136)	Fidelity Fund	$0.00	$0.00	$6,268.00	$0.00
(136)	UBS Fund	$0.00	$0.00	$1,871.00	$0.00
(136)	Black Rock Temp Fund	$0.00	$0.00	$365.00	$0.00
(136)	Deutsche Money Mkt Series	$0.00	$0.00	$2,171.00	$0.00
(136)	Dreyfus Instl Cash Advantage	$0.00	$0.00	$74.00	$0.00
(136)	Federated Prime Cash Oblig	$0.00	$0.00	$470.00	$0.00
(136)	Goldman FSQ Money Market	$0.00	$0.00	$5,326.00	$0.00
(136)	Invesco Liquid Assets	$0.00	$0.00	$6,254.00	$0.00
(136)	WAM Instit Cash Resrvs	$0.00	$16,031,632.00	$7,032.00	$0.00
(136)	Wells Fargo Adv Heritage	$0.00	$0.00	$5,259.00	$0.00
(136)	SunTrust Bank	$0.00	$0.00	$7,847.00	$0.00
(136)		$0.00	$0.00	$0.00	$0.00

Note:
Revenues for Year include Dividend Income from Investments.

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Investments in Subsidiary Companies (123.1) (Ref Page: 224)

	Description	Date Acquired (b)	Date Maturity (c)	Investment Beg of Yr. (d)	Equity in Subsidiary (e)	Revenues (f)	Investment End Yr (g)	Invest Disposed of (h)
	OVEC (5.63%)			$0.00	$0.00	$0.00	$0.00	$0.00
	Common Stock $100 Par Value, 5,630 shares			$0.00	$0.00	$0.00	$0.00	$0.00
	700 shares	11/18/1952		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	1/8/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	2/25/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	4/10/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	5/12/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	1400 shares	7/27/1953		$140,000.00	$0.00	$0.00	$140,000.00	$0.00
	730 shares	3/4/2005		$104,286.00	$0.00	$0.00	$104,286.00	$0.00
TOTAL				$594,286.00	$0.00	$0.00	$594,286.00	$0.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

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Prepayments (Ref Page: 230)

	Balance at End of Year
Prepaid Insurance	$3,075,205.00
Prepaid Rents	$0.00
Prepaid Taxes	$1,421,173.00
Prepaid Interest	$0.00
Miscellaneous Prepayments	$1,976,159.00
Total	$6,472,537.00

Note:
The Miscellaneous Prepayments line is compromised of Tennessee Valley Authority $544,901, EEI Dues $337,433, US Postage Prepaid $279,274, Rights of Way $173,334, LGE Center Prepaid Rent $120,503, Open Systems International Inc. $91,014, Risk Management & Workers Compensation $90,500, US Lease Prepaid $77,850, Platts Subscription $76,149, Siemen's Energy - Paddy's Run $39,107, Siemen's Energy - Cane Run $38,080, APD Funding $34,510, Doble $22,109, North American Transmission Forum $18,836, Platts IT Subscription $18,172, Gartner Inc. $7,399, Standard & Poor's Svc $6,167 and SNL Software License Fees $821.

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Extraordinary Property Losses (182.1) (Ref Page: 230)

	Description	Balance Beg Yr (b)	Total Loss (b)	Losses During Yr	Acct (d)	Written Off (e)	Balance (f)
		$0.00	$0.00	$0.00		$0.00	$0.00
TOTAL		$0.00	$0.00			$0.00	$0.00

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Unrecovered Plant and Regulatory Study costs (182.2) (Ref Page: 230)

	Description	Balance Beg Yr (b)	Total Loss (b)	Losses During Yr	Acct (d)	Written Off (e)	Balance (f)
		$0.00	$0.00	$0.00		$0.00	$0.00
TOTAL		$0.00	$0.00			$0.00	$0.00

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Other Regulatory Assets (Acct 182.3) (Ref Page: 232)

Description and Purpose	Bal Beg Yr (b)	Debits (c)	Written Off Acct (d)	Written Off Amt (e)	Balance End Yr (f)
ASC 715 - Pension and Postretirement	$214,538,462.00	$31,966,740.00	Various	$37,548,834.00	$208,956,368.00
Asset Retirement Obligation - Electric	$24,857,861.00	$29,252,876.00	Various	$740,182.00	$53,370,555.00
Wind Storm 2008 (Aug-10 to Jul-20)	$13,143,352.00	$0.00	593	$2,354,033.00	$10,789,319.00
ASC 740 - Income Taxes	$13,792,117.00	$14,319.00	282/283	$279,552.00	$13,526,884.00
Long-Term Interest Rate Swap Non-LKE Affiliate	$33,263,681.00	$10,627,689.00	Various	$825,497.00	$43,065,873.00
Asset Retirement Obligation - Gas	$3,388,874.00	$1,947,945.00	230/403.1	$1,713,247.00	$3,623,572.00
Asset Retirement Obligation - Common	$0.00	$0.00	230/403.1	$0.00	$0.00
DSM Cost Recovery-Under-Recovery	$0.00	$0.00	440-445	$0.00	$0.00
Winter Storm 2009-Electric/Gas (Aug-10 to Jul-20)	$24,476,436.00	$0.00	571/593/880	$4,383,840.00	$20,092,596.00
Environmental Cost Recovery	$3,840,000.00	$10,486,000.00	440-445	$1,020,000.00	$13,306,000.00
Performance-Based Rates	$1,711,218.00	$1,218,784.00	803	$1,500,798.00	$1,429,204.00
Gas Line Tracker	$0.00	$1,286,856.00	480-482	$0.00	$1,286,856.00
2014 Rate Case Expense-Electric (Jul-15 to Jun-18)	$753,342.00	$383,968.00	146/928	$189,600.00	$947,710.00
2014 Rate Case Expense-Gas (Jul-15 to Jun-18)	$188,335.00	$95,992.00	146/928	$47,400.00	$236,927.00
Carbon Mgmt Research Group (Aug-10 to Jul-20)	$154,470.00	$175,560.00	930.2	$175,560.00	$154,470.00
Fuel Adjustment Clause	$1,562,000.00	$2,088,000.00	440-445	$3,650,000.00	$0.00
Gas Supply Clause	$13,794,977.00	$2,074,932.00	803	$15,869,909.00	$0.00
Long-Term Interest Rate Swap	$47,988,828.00	$0.00	244	$843,464.00	$47,145,364.00
Coal Contracts (Nov-10 to Dec-15) - PAA	$167,241.00	$0.00	253	$167,241.00	$0.00
Swap Termination (Aug-10 to Apr-35)	$7,901,428.00	$0.00	930.2	$388,659.00	$7,512,769.00
Forward Starting Swaps	$0.00	$0.00	0	$0.00	$0.00

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Other Regualatory Assets (Acct 182.3) (Ref Page: 232)

	Description and Purpose	Bal Beg Yr (b)	Debits (c)	Written Off Acct (d)	Written Off Amt (e)	Balance End Yr (f)
	Pension Gain/Loss Amortization - 15 Year	$0.00	$5,747,780.00	Various	$0.00	$5,747,780.00
	KY Consortium for Carbon Storage (Aug-10 to Jul-14	$0.00	$0.00	930.2	$0.00	$0.00
	Unamortized Debt Expense (Aug-10 to Apr-35) - PAA	$2,513,378.00	$0.00	181	$150,689.00	$2,362,689.00
	Summer Storm 2011 (Jan-13 to Dec-17)	$4,831,275.00	$0.00	593	$1,610,425.00	$3,220,850.00
	2011 General Mgmt Audit-Electric (Jan-13 to Dec-15	$30,527.00	$0.00	928	$30,527.00	$0.00
	2011 General Mgmt Audit-Gas (Jan-13 to Dec-15)	$9,941.00	$0.00	928	$9,941.00	$0.00
	EKPC FERC Transmission Costs (Mar-09 to Feb-14)	$0.00	$0.00	456/566	$0.00	$0.00
	2012 Rate Case Expense-Electric (Jan-13 to Dec-15)	$298,214.00	$0.00	928	$298,214.00	$0.00
	2012 Rate Case Expense-Gas (Jan-13 to Dec-15)	$94,960.00	$0.00	928	$94,960.00	$0.00
Total		$413,300,917.00	$97,367,441.00		$73,892,572.00	$436,775,786.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

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Miscellaneous Deferred Debits (Acct 186) (Ref Page: 233)

	Description (a)	Bal Beg Yr (b)	Debits (c)	CR Acct (d)	CR Amt (e)	Bal End Yr (c)
	Goodwill	$389,157,352.00	$0.00	0	$0.00	$389,157,352.00
	OVEC Pwr Purch Contract (Nov-10 to Mar-26) - PAA	$63,856,830.00	$0.00	254	$5,756,807.00	$58,100,023.00
	Coal Contracts (Nov-10 to Dec-16) - PAA	$25,385,051.00	$0.00	254	$17,761,589.00	$7,623,462.00
	Cane Run 7 LTPC Asset	$0.00	$1,863,539.00	0	$0.00	$1,863,539.00
	Valuation of SO2 Allow (Nov-10 to Dec-40) - PAA	$1,341,711.00	$0.00	254	$179,745.00	$1,161,966.00
	Customer Credit Accounts Receivable	$637,031.00	$0.00	142	$34,627.00	$602,404.00
	Cellular Antenna Billable Chgs	$52,381.00	$0.00	Various	$11,163.00	$41,218.00
	Financing Expense	$38,531.00	$1,474.00	0	$0.00	$40,005.00
Misc. Work in Progress						
Total		$480,468,887.00	$1,865,013.00		$23,743,931.00	$458,589,969.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Accumulated Deferred Income Taxes (Acct 190) (Ref Page: 234)

Description	Bal Beg Yr	Amt 410.1 (c)	Amt 411.1 (d)	Amt 410.2 (e)	Amt 411.2 (f)
Account 190					
Electric	$160,819,523.00	$66,495,952.00	$151,620,088.00	$0.00	$0.00
Gas	$31,444,640.00	$16,098,481.00	$26,615,067.00	$0.00	$0.00
Other (Define)	$260,281.00	$0.00	$0.00	$230,967.00	$42,045.00
Total	$192,524,444.00	$82,594,433.00	$178,235,155.00	$230,967.00	$42,045.00
Other (Specify)					
TOTAL Acct 190	$192,524,444.00	$82,594,433.00	$178,235,155.00	$230,967.00	$42,045.00
Classification of TOTAL					
Federal INcome TAx	$161,141,344.00	$74,949,592.00	$167,639,289.00	$197,394.00	$37,612.00
State Income Tax	$31,383,100.00	$7,644,841.00	$10,595,866.00	$33,573.00	$4,433.00
Local Income Tax					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Accumulated Deferred Income Taxes (Acct 190) (Ref Page: 234) (Part Two)

Description	Debit Adj Acct (g)	Debit Amount (h)	Credit Acct (i)	Credit Amount (j)	Balance End Yr (k)
Account 190					
Electric		$0.00	254	$1,006,499.00	$244,937,160.00
Gas		$0.00	254/283	$427,718.00	$41,533,508.00
Other (Define)		$0.00		$0.00	$71,359.00
Total		$0.00		$1,434,217.00	$286,542,027.00
Other (Specify)					
TOTAL Acct 190		$0.00		$1,434,217.00	$286,542,027.00
Classification of TOTAL					
Federal INcome TAx		$0.00		$1,213,001.00	$252,458,258.00
State Income Tax		$0.00		$221,216.00	$34,083,769.00
Local Income Tax					

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Capital Stock (Accounts 201 and 204) (Ref Page: 250)

	Class, Series and Name of	Num Shares Auth (b)	Par or Stated Val (c)	Call Price (d)	Outstanding Shares (e)
Common Stock					
	Without Par Value	75,000,000	$0.00	$0.00	$21,294,223.00
Total Common Stock		75,000,000	$0.00	$0.00	$21,294,223.00
Preferred Stock					
	$25 Par Value	1,720,000	$0.00	$0.00	$0.00
	Without Par Value	6,750,000	$0.00	$0.00	$0.00
Total Preferred Stock		8,470,000	$0.00	$0.00	$0.00
TOTAL Capital Stock		83,470,000	$0.00	$0.00	$21,294,223.00
Other					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Capital Stock (Accounts 201 and 204) (Ref Page: 250) (Part Two)

	Class, Series and Name	Outstanding Amt (f)	Num Held Rqd 217 (g)	Cost Held Rqd 217 (h)	Num Held Sinking (i)	Num Held Amount (j)
Common Stock						
	Without Par Value	$425,170,424.00	0	$0.00	0	$0.00
Total Common Stock		$425,170,424.00	0	$0.00	0	$0.00
Preferred Stock						
	$25 Par Value	$0.00	0	$0.00	0	$0.00
	Without Par Value	$0.00	0	$0.00	0	$0.00
Total Preferred Stock		$0.00	0	$0.00	0	$0.00
TOTAL Capital Stock		$425,170,424.00	0	$0.00	0	$0.00
Other						

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

Amounts in Column (e) represent the number of shares outstanding and not dollar amounts as shown.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Page: 252)

	Description (a)	* (b)	Shares (c)	Amount (d)
Capital Stock Subscribed (202,205)				
	Not applicable for LG&E		0	$0.00
Total Capital Stock Subscribed				
Stock Liability for Conversion (203,206)				
	Not applicable for LG&E		0	$0.00
Total Stock Liability for Conversion				
Premium on Capital Stock (207)				
	Not applicable for LG&E		0	$0.00
Total Premium on Capital Stock (207)				
Installments Received on Capital Stock (212)				
	Not applicable for LG&E		0	$0.00
Total Installments Received on Capital Stock (212)				

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Other Paid-In Capital (208-211) (Ref Page: 253)

	Item (a)	Amount (b)
(a) Donations Received from Stockholders (208)		
Total (208)		
(b) Reduction in Par or Stated Value (209)		
Total (209)		
(c) Gain or Resale or Cancellation of Reacquired Capital Stock (210)		
Total (210)		
(d) Miscellaneous Paid-In Capital (211)		
	Contributed Capital - Balance January 1, 2015	$1,521,167,368.00
	Contributed Capital June 30, 2015	$20,000,000.00
	Contributed Capital December 31, 2015	$70,000,000.00
Total (211)		$1,611,167,368.00
Total Accts 208-211		$1,611,167,368.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Discount on Capital Stock (Act 213) (Ref Page: 254)

	Class and Series (a)	Balance End Yr (b)
	not applicable for LG&E	0.0000
	0	0.0000
TOTAL		0.0000

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Capital Stock Expense (Act 214) (Ref Page: 254)

	Class and Series (a)	Balance End Yr (b)
	Expense on Common Stock	$835,889.00
TOTAL		$835,889.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Long-Term Debt (221,222,223 and 224) (Ref Page: 256)

	Class Series and Name (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (d)	Interest Rate in % (e)
Acct 221 Bonds					
(221)	Pollution Control Bonds:			$0.00	0.0000
(221)	Jefferson Co. 2000 Series A, due 05/01/2027, Var	5/19/2000	5/1/2027	$25,000,000.00	0.0000
(221)	Trimble Co. 2000 Series A, due 08/01/2030, Var	8/9/2000	8/1/2030	$83,335,000.00	0.0000
(221)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	9/11/2001	9/1/2027	$10,104,000.00	0.0000
(221)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	3/6/2002	9/1/2026	$22,500,000.00	0.0000
(221)	Trimble Co. 2001 Series A, due 09/01/2026, 1.05%	3/6/2002	9/1/2026	$27,500,000.00	1.0500
(221)	Jefferson Co. 2001 Series B, due 11/01/2027, 1.35%	3/22/2002	11/1/2027	$35,000,000.00	1.3500
(221)	Trimble Co. 2001 Series B, due 11/01/2027, 1.35%	3/22/2002	11/1/2027	$35,000,000.00	1.3500
(221)	Trimble Co. 2002 Series A, due 10/01/2032, Var	10/23/2002	10/1/2032	$41,665,000.00	0.0000
(221)	Louisville Metro 2003A, due 10/01/2033, 1.65%	11/20/2003	10/1/2033	$128,000,000.00	1.6500
(221)	Louisville Metro 2005A, due 02/01/2035, 2.20%	4/13/2005	2/1/2035	$40,000,000.00	2.2000
(221)	Trimble Co. 2007 Series A, due 06/01/2033, 4.60%	4/26/2007	6/1/2033	$60,000,000.00	4.6000
(221)	Louisville Metro 2007A, due 06/01/2033, 1.15%	4/26/2007	6/1/2033	$31,000,000.00	1.1500
(221)	Louisville Metro 2007B, due 06/01/2033, 1.60%	4/26/2007	6/1/2033	$35,200,000.00	1.6000
(221)	Interest Rate Swaps:			$0.00	0.0000
(221)	First Mortgage Bonds:			$0.00	0.0000
(221)	2010 due 11/15/2015, 1.625%	11/16/2010	11/15/2015	$0.00	1.6250
(221)	2010 due 11/15/2040, 5.125%	11/16/2010	11/15/2040	$285,000,000.00	5.1250
(221)	2013 due 11/15/2043, 4.650%	11/14/2013	11/15/2043	$250,000,000.00	4.6500
(221)	2015 due 10/01/2025, 3.300%	9/28/2015	10/1/2025	$300,000,000.00	3.3000
(221)	2015 due 10/01/2045, 4.375%	9/28/2015	10/1/2045	$250,000,000.00	4.3750
Total (221)				$1,659,304,000.00	
Acct 222 Reacquired Bonds					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Long-Term Debt (221,222,223 and 224) (Ref Page: 256)

	Class Series and Name (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (d)	Interest Rate in % (e)
(222)					
Total (222)					
Acct 223 Advances from Associated Companies					
(223)	Debt with Associated Companies			$0.00	0.0000
Total (223)				$0.00	
Acct 224 Other Long Term Debt					
(224)	Purchase Accounting Adjust. for FV Measure			$0.00	0.0000
(224)	Trimble Co. 2007 Series A, due 06/01/2033, 4.60%			($1,590,554.00)	4.6000
Total (224)				($1,590,554.00)	

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two)

	Class Series and Name (a)	Interest Amount (f)	Held - Reaquired Bonds	Held - Sinking and Other	Redemption Price Per $100
Acct 221 Bonds					
(221)	Pollution Control Bonds:	$0.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2000 Series A, due 05/01/2027, Var	$199,338.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2000 Series A, due 08/01/2030, Var	$157,411.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	$15,095.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	$51,639.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2001 Series A, due 09/01/2026, 1.05%	$288,750.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2001 Series B, due 11/01/2027, 1.35%	$472,500.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2001 Series B, due 11/01/2027, 1.35%	$472,500.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2002 Series A, due 10/01/2032, Var	$100,930.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2003A, due 10/01/2033, 1.65%	$2,112,000.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2005A, due 02/01/2035, 2.20%	$880,000.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2007 Series A, due 06/01/2033, 4.60%	$2,760,000.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2007A, due 06/01/2033, 1.15%	$356,500.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2007B, due 06/01/2033, 1.60%	$563,200.00	$0.00	$0.00	$0.00
(221)	Interest Rate Swaps:	$7,942,291.00	$0.00	$0.00	$0.00
(221)	First Mortgage Bonds:	$0.00	$0.00	$0.00	$0.00
(221)	2010 due 11/15/2015, 1.625%	$3,543,403.00	$0.00	$0.00	$0.00
(221)	2010 due 11/15/2040, 5.125%	$14,606,250.00	$0.00	$0.00	$0.00
(221)	2013 due 11/15/2043, 4.650%	$10,191,295.00	$0.00	$0.00	$0.00
(221)	2015 due 10/01/2025, 3.300%	$2,923,284.00	$0.00	$0.00	$0.00
(221)	2015 due 10/01/2045, 4.375%	$3,082,166.00	$0.00	$0.00	$0.00
Total (221)		$50,718,552.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two)

	Class Series and Name (a)	Interest Amount (f)	Held - Reaquired Bonds	Held - Sinking and Other	Redemption Price Per $100
Acct 222 Reacquired Bonds					
(222)					
Total (222)					
Acct 223 Advances from Associated Companies					
(223)	Debt with Associated Companies	$0.00	$0.00	$0.00	$0.00
Total (223)		$0.00	$0.00	$0.00	$0.00
Acct 224 Other Long Term Debt					
(224)	Purchase Accounting Adjust. for FV Measure	$0.00	$0.00	$0.00	$0.00
(224)	Trimble Co. 2007 Series A, due 06/01/2033, 4.60%	$91,298.00	$0.00	$0.00	$0.00
Total (224)		$91,298.00	$0.00	$0.00	$0.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Unamortized Debt Expense (181,225,226) (Ref Page: 258)

	Designation of Long-Term	Principal Amount of Debt	Total Expense Premium or	Amortization Period From (d)	Amortization Period To (e)
Acct 181					
(181)	Unamortized Debt Expense:	$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	$10,104,000.00	$526,085.00	9/11/2001	9/1/2027
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Trimble Co. 2000 Series A, due 08/01/2030, Var	$83,335,000.00	$1,154,826.00	8/9/2000	8/1/2030
(181)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	$22,500,000.00	$242,653.00	3/6/2002	9/1/2026
(181)	Trimble Co. 2001 Series A, due 09/01/2026, 1.05%	$27,500,000.00	$263,855.00	3/6/2002	9/1/2026
(181)	Jefferson Co. 2001 Series B, due 11/01/2027, 1.35%	$35,000,000.00	$281,244.00	3/22/2002	11/1/2027
(181)	Trimble Co. 2001 Series B, due 11/01/2027, 1.35%	$35,000,000.00	$281,283.00	3/22/2002	11/1/2027
(181)	Trimble Co. 2002 Series A, due 10/01/2032, Var	$41,665,000.00	$1,112,006.00	10/23/2002	10/1/2032
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	$60,000,000.00	$1,239,280.00	4/26/2007	6/1/2033
(181)	FMB 2010 due 11/15/2015, 1.625%	$250,000,000.00	$2,563,689.00	11/16/2010	11/15/2015
(181)	FMB 2010 due 11/15/2040, 5125%	$285,000,000.00	$3,570,026.00	11/16/2010	11/15/2040
(181)	Revolving Credit Facility	$0.00	$6,415,918.00	11/1/2010	7/28/2019
(181)	Purchase Accounting Adjustment	$0.00	($3,698,836.00)	11/1/2010	6/1/2033
(181)	Louisville Metro 2003A, due 10/01/2033, 1.650%	$128,000,000.00	$4,792,737.00	11/20/2003	10/1/2033

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Unamortized Debt Expense (181,225,226) (Ref Page: 258)

	Designation of Long-Term	Principal Amount of Debt	Total Expense Premium or	Amortization Period From (d)	Amortization Period To (e)
(181)	Louisville Metro 2007B, due 06/01/2033, 1.600%	$35,200,000.00	$1,085,694.00	4/26/2007	6/1/2033
(181)	Jefferson County 2000 Series A, due 05/01/2027, Va	$25,000,000.00	$883,831.00	5/19/2000	5/1/2027
(181)	Louisville Metro 2005A, due 02/01/2035, 2.200%	$40,000,000.00	$1,428,142.00	4/13/2005	2/1/2035
(181)	Louisville Metro 2007A, due 06/01/2033, 1.150%	$31,000,000.00	$938,023.00	4/26/2007	6/1/2033
(181)	FMB 2013 due 11/15/2043, 4.650%	$250,000,000.00	$2,742,758.00	11/14/2013	11/15/2043
(181)	S-3 SEC Shelf Registration	$0.00	$6,667.00	3/28/2012	3/27/2015
(181)	FMB 2015 due 10/01/2025, 3.300%	$300,000,000.00	$2,372,643.00	9/28/2015	10/1/2025
(181)	FMB 2015 due 10/01/2045, 4.375%	$250,000,000.00	$2,568,352.00	9/28/2015	10/1/2045
Total (181)		$1,909,304,000.00	$30,770,876.00		
Acct 225					
(225)					
Total (225)					
Acct 226					
(226)	Unamortized Debt Discount	$0.00	$0.00		
(226)	FMB 2010 due 11/15/2015, 1.625%	$250,000,000.00	$882,500.00	11/16/2010	11/15/2015
(226)	FMB 2010 due 11/15/2040, 5.125%	$285,000,000.00	$3,100,600.00	11/16/2010	11/15/2040
(226)	FMB 2013 due 11/15/2043, 4.650%	$250,000,000.00	$1,800,000.00	11/14/2013	11/15/2043
(226)	FMB 2015 due 10/01/2025, 3.300%	$300,000,000.00	$129,000.00	9/28/2015	10/1/2025
(226)	FMB 2015 due 10/01/2045, 4.375%	$250,000,000.00	$207,500.00	9/28/2015	10/1/2045
Total (226)		$1,335,000,000.00	$6,119,600.00		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Unamortized Debt Expense (181,225,226) (Ref Page: 258) (Part Two)

	Designation of Long-Term	Beginning of Year (f)	Debits (g)	Credits (h)	Balance End of Year (i)
Acct 181					
(181)	Unamortized Debt Expense:	$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	$258,549.00	$0.00	$19,857.00	$238,692.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Trimble Co. 2000 Series A, due 08/01/2030, Var	$603,569.00	$0.00	$37,820.00	$565,749.00
(181)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	$115,811.00	$0.00	$9,812.00	$105,999.00
(181)	Trimble Co. 2001 Series A, due 09/01/2026, 1.05%	$164,028.00	$30,665.00	$54,631.00	$140,062.00
(181)	Jefferson Co. 2001 Series B, due 11/01/2027, 1.35%	$189,406.00	$30,673.00	$57,411.00	$162,668.00
(181)	Trimble Co. 2001 Series B, due 11/01/2027, 1.35%	$189,547.00	$30,009.00	$57,286.00	$162,270.00
(181)	Trimble Co. 2002 Series A, due 10/01/2032, Var	$660,957.00	$0.00	$36,519.00	$624,438.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	$875,313.00	$0.00	$47,502.00	$827,811.00
(181)	FMB 2010 due 11/15/2015, 1.625%	$452,334.00	$0.00	$452,334.00	$0.00
(181)	FMB 2010 due 11/15/2040, 5125%	$3,084,624.00	$0.00	$119,144.00	$2,965,480.00
(181)	Revolving Credit Facility	$2,702,551.00	$0.00	$692,294.00	$2,010,257.00
(181)	Purchase Accounting Adjustment	($2,513,378.00)	$151,511.00	$822.00	($2,362,689.00)
(181)	Louisville Metro 2003A, due 10/01/2033, 1.650%	$343,836.00	$0.00	$152,215.00	$191,621.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Unamortized Debt Expense (181,225,226) (Ref Page: 258) (Part Two)

	Designation of Long-Term	Beginning of Year (f)	Debits (g)	Credits (h)	Balance End of Year (i)
(181)	Louisville Metro 2007B, due 06/01/2033, 1.600%	$131,940.00	$0.00	$54,300.00	$77,640.00
(181)	Jefferson County 2000 Series A, due 05/01/2027, Va	$103,203.00	$0.00	$53,557.00	$49,646.00
(181)	Louisville Metro 2005A, due 02/01/2035, 2.200%	$326,387.00	$0.00	$67,438.00	$258,949.00
(181)	Louisville Metro 2007A, due 06/01/2033, 1.150%	$155,702.00	$0.00	$63,800.00	$91,902.00
(181)	FMB 2013 due 11/15/2043, 4.650%	$2,639,194.00	$0.00	$91,179.00	$2,548,015.00
(181)	S-3 SEC Shelf Registration	$527.00	$0.00	$527.00	$0.00
(181)	FMB 2015 due 10/01/2025, 3.300%		$2,372,643.00	$58,635.00	$2,314,008.00
(181)	FMB 2015 due 10/01/2045, 4.375%		$2,568,352.00	$21,624.00	$2,546,728.00
Total (181)		$10,484,100.00	$5,183,853.00	$2,148,707.00	$13,519,246.00
Acct 225					
(225)					
Total (225)					
Acct 226					
(226)	Unamortized Debt Discount	$0.00	$0.00	$0.00	$0.00
(226)	FMB 2010 due 11/15/2015, 1.625%	$153,935.00	$0.00	$153,935.00	$0.00
(226)	FMB 2010 due 11/15/2040, 5.125%	$2,674,173.00	$0.00	$103,294.00	$2,570,879.00
(226)	FMB 2013 due 11/15/2043, 4.650%	$1,732,306.00	$0.00	$59,956.00	$1,672,350.00
(226)	FMB 2015 due 10/01/2025, 3.300%		$129,000.00	$3,369.00	$125,631.00
(226)	FMB 2015 due 10/01/2045, 4.375%		$207,500.00	$1,828.00	$205,672.00
Total (226)		$4,560,414.00	$336,500.00	$322,382.00	$4,574,532.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Unamortized Loss and Gain on Reqcquired Debt (189,257) (Ref Page: 260)

	Designation of Long-	Date Reacquired (b)	Principle of Debt	Net Gain or Loss (d)	Balance Beginning of	Balance End of Year (f)
Acct 189						
(189)	Gas Reacquired Debt		$0.00	$0.00	$0.00	$0.00
(189)	1985 Series J, due 07/01/1995	8/1/1990	$25,000,000.00	$787,340.00	$217,107.00	$199,501.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1976 Series B, due 09/01/2006	8/1/1993	$35,200,000.00	$439,383.00	$97,679.00	$92,376.00
(189)	1975 Series A, due 09/01/2000	10/1/1992	$31,000,000.00	$286,757.00	$83,680.00	$79,138.00
(189)	1987 Series A, due 08/01/1997	10/1/1992	$60,000,000.00	$2,574,187.00	$754,865.00	$713,887.00
(189)	1990 Series A, due 06/15/2015	6/1/2000	$25,000,000.00	$2,171,404.00	$998,977.00	$917,965.00
(189)	1990 Series A TC, due 11/01/2020	8/1/2000	$83,335,000.00	$4,298,037.00	$2,238,790.00	$2,095,148.00
(189)	1996 Series A JC, due 09/01/2026	3/1/2002	$22,500,000.00	$1,896,244.00	$903,124.00	$825,723.00
(189)	1996 Series A TC, due 09/01/2026	3/1/2002	$27,500,000.00	$1,601,630.00	$762,751.00	$697,380.00
(189)	1997 Series A JC, due 11/01/2027	3/1/2002	$35,000,000.00	$1,256,362.00	$629,284.00	$580,256.00
(189)	1997 Series A TC, due 11/01/2027	3/1/2002	$35,000,000.00	$1,251,639.00	$626,977.00	$578,129.00
(189)	1990 Series B TC, due 10/01/2020	10/1/2002	$41,665,000.00	$1,671,182.00	$990,634.00	$934,842.00
(189)	1995 Series A JC, due 11/01/2005	11/1/2005	$40,000,000.00	$1,397,647.00	$940,661.00	$893,845.00
(189)	1993 Series B JC, due 11/01/2003	11/1/2003	$26,000,000.00	$5,683,169.00	$3,564,510.00	$3,373,625.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1992 Series A JC, due 09/01/2017	4/26/2007	$31,000,000.00	$130,784.00	$92,115.00	$87,115.00
(189)	1992 Series A TC, due 09/01/2017	4/26/2007	$60,000,000.00	$172,943.00	$121,809.00	$115,197.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Unamortized Loss and Gain on Reqcquired Debt (189,257) (Ref Page: 260)

	Designation of Long-	Date Reacquired (b)	Principle of Debt	Net Gain or Loss (d)	Balance Beginning of	Balance End of Year (f)
(189)	1993 Series A JC, due 08/15/2013	4/26/2007	$35,200,000.00	$74,067.00	$52,167.00	$49,335.00
(189)	2005 Series A JC, due 02/01/2035	3/24/2008	$40,000,000.00	$1,325,894.00	$758,414.00	$720,668.00
(189)	2000 Series A JC, due 05/01/2027	5/1/2008	$25,000,000.00	$692,833.00	$307,096.00	$282,192.00
(189)	2003 Series A JC, due 09/01/2033	7/8/2008	$128,000,000.00	$3,076,081.00	$2,290,990.00	$2,168,304.00
(189)	2007 Series A JC, due 06/01/2033	4/4/2008	$31,000,000.00	$915,910.00	$475,388.00	$449,582.00
(189)	2007 Series B JC, due 06/01/2033	4/4/2008	$35,200,000.00	$620,418.00	$454,783.00	$430,095.00
(189)	Revolving Credit Facility	7/28/2014	$500,000,000.00	$285,775.00	$261,204.00	$204,081.00
(189)	1996 Series A TC, due 09/01/2026	12/15/2014	$27,500,000.00	$126,410.00	$125,908.00	$115,120.00
(189)	1997 Series A JC, due 11/01/2027	12/15/2014	$35,000,000.00	$141,675.00	$141,188.00	$130,190.00
(189)	1997 Series A TC, due 11/01/2027	12/15/2014	$35,000,000.00	$141,700.00	$141,163.00	$130,168.00
Total (189)			$1,470,100,000.00	$33,019,471.00	$18,031,264.00	$16,863,862.00
Acct 257						
(257)						
Total (257)						

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Ref Page: 261)

	Details (a)	Amount (b)
Net Income for the Year		$185,363,790.00
Reconciling Items for the Year		
Taxable Income Not Reported on Books		
	Purchased Gas Adjustment	$14,489,662.00
	Contribution in Aid of Construction	$6,245,359.00
	Fuel Adjustment Clause	$3,948,000.00
	Demand Side Management	$2,992,854.00
Deductions Recorded on Books Not Deducted For Return		
	Federal Income Taxes - Utility Operating Income	($13,679,235.00)
	Federal Income Taxes - Other Income and Deductions	($1,834,650.00)
	Provision for Deferred Income Taxes	$127,672,181.00
	Net Operating Loss	$217,672,526.00
	Capitalized Interest	$16,079,287.00
	Storm Damages	$8,348,297.00
	Obsolete Inventory	$8,200,000.00
	Performance Incentive	$1,978,479.00
	Loss on Reacquired Debt - Amortization	$1,167,401.00
	Prepaid Insurance	$1,376,318.00
	Nondeductible Expenses	$604,701.00
	Other	$1,136,739.00
	Purchase Accounting Adjustments - FMV Bonds	$91,298.00
Income Recorded on Books Not Included in Return		
	Environmental Cost Recovery	$9,466,000.00
	Gas Line Tracker	$3,950,650.00
	Amortization of Investment Tax Credit	$1,338,634.00
	Customer Advances for Construction	$805,405.00
		$0.00
Deductions on Return Not Charged Against Book Income		
	Tax over Book Depreciation, Net and Repairs	$535,298,202.00
	Interest Rate Swaps	$44,499,577.00
	Cost of Removal	$27,915,563.00
	Capitalized Gas Inventory	$1,900,000.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Ref Page: 261)

	Details (a)	Amount (b)
	Current State Income Tax	$963,329.00
	Other	$2,842,964.00
Federal Tax Net Income		($47,127,317.00)
Show Computation of Tax		
	35% Rounded	($16,494,561.00)
	Add: Adjustment of Prior Years' Taxes & Other	$980,676.00
	Total:	($15,513,885.00)

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262)

	Kind of Instruction (a)	Bal Beg Yr Taxes Accr (b)	Bal Beg Yr Prepaid Taxes (c)	Taxes Chrg (d)
	Federal:	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	($85,281,871.00)
	FICA	$775,836.00	$0.00	$7,864,673.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00
	Income	$1,948,239.00	$0.00	$3,325,113.00
	Public Service Commission	$0.00	$1,358,178.00	$2,779,351.00
	Use (Kentucky)	$650,284.00	$0.00	$6,663,007.00
	Use (Indiana)	$0.00	$0.00	$58,004.00
		$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00
	Unemployment Insurance	$171,637.00	$0.00	$144,970.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
	Miscellaneous	$0.00	$0.00	$94,810.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00
	Property Taxes	$15,323,569.00	$0.00	$25,868,786.00
Total		$18,869,565.00	$1,358,178.00	($38,483,157.00)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262) (Part Two)

	Kind of Instruction (a)	Taxes Paid (e)	Adj (f)	Bal Accr - 236 (g)	Bal Prepaid - 165 (h)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	($85,281,871.00)	$0.00	$0.00	$0.00
	FICA	$7,696,359.00	$0.00	$944,150.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Income	$4,288,442.00	$0.00	$984,910.00	$0.00
	Public Service Commission	$2,842,346.00	$0.00	$0.00	$1,421,173.00
	Use (Kentucky)	$6,567,321.00	$0.00	$745,970.00	$0.00
	Use (Indiana)	$58,004.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$269,442.00	$0.00	$47,165.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Miscellaneous	$94,810.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$23,989,031.00	$0.00	$17,203,324.00	$0.00
Total		($39,476,116.00)	$0.00	$19,925,519.00	$1,421,173.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Taxes Accr, Prepd and Charged - Distribution of Taxes (Ref Page: 262)

	Kind of Instruction (a)	Electric (408.1, 409.1) (i)	Gas (408.1, 409.1) (j)	Other (408.1,409.1) (k)	Other Inc and Ded (l)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	($12,314,375.00)	($1,364,860.00)	$0.00	($1,834,650.00)
	FICA	$6,749,475.00	$1,891,430.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Income	$1,867,677.00	$1,792,023.00	$0.00	($334,587.00)
	Public Service Commision	$2,121,000.00	$658,351.00	$0.00	$0.00
	Use (Kentucky)	$0.00	$0.00	$0.00	$0.00
	Use (Indiana)	$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$159,007.00	$33,279.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Miscellaneous	$74,900.00	$19,910.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$19,235,773.00	$6,456,922.00	$0.00	$7,003.00
Total		$17,893,457.00	$9,487,055.00	$0.00	($2,162,234.00)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Taxes Accr, Prepd and Charged - Distribution of Taxes (Ref Page: 262) (Part Two)

	Kind of Instruction (a)	Ext Items (409.3) (m)	Other Opn Income (n)	Adj to Ret. Earnings (439)	Other (p)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$0.00	($69,767,986.00)
	FICA	$0.00	$0.00	$0.00	($776,232.00)
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$0.00	$0.00
	Public Service Commision	$0.00	$0.00	$0.00	$0.00
	Use (Kentucky)	$0.00	$0.00	$0.00	$6,663,007.00
	Use (Indiana)	$0.00	$0.00	$0.00	$58,004.00
		$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$0.00	$0.00	$0.00	($47,316.00)
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Miscellaneous	$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$0.00	$0.00	$0.00	$169,088.00
Total		$0.00	$0.00	$0.00	($63,701,435.00)

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Miscellaneous Current and Accrued Liabilities (242) (Ref Page: 268)

	Item (a)	Balance End Yr (b)
	Vested Vacation Pay Accrued	$6,050,334.00
	Customer Overpayments	$4,967,746.00
	No-Notice Gas Payable	$3,323,551.00
	Post Retirement Benefits	$2,896,531.00
	IBNP Medical and Dental Reserve	$1,311,064.00
	Home Energy Assistance	$890,880.00
	Retirement Income Liability	$890,408.00
	Franchise Fee Payable	$476,016.00
	Unearned Revenue	$416,881.00
	Other	$172,853.00
TOTAL		$21,396,264.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Other Deferred Credits (253) (Ref Page: 269)

Description (a)	Balance Beg Yr (b)	Debits Acct (c)	Debit Amt (d)	Credits (e)	Balance End Yr (f)
Long-Term Retainage	$10,663,076.00	232	$8,688,394.00	$0.00	$1,974,682.00
Corporate Headquarters Lease (Jul-12 to Dec-25)	$1,159,909.00	0	$0.00	$41,576.00	$1,201,485.00
Prepaid Trans Sys Fee: MCI (Apr-09 to Apr-29)	$484,483.00	454	$36,796.00	$0.00	$447,687.00
Uncertain Tax Position - Federal	$201,769.00	0	$0.00	$0.00	$201,769.00
Deferred Compensation	$669,103.00	146	$485,659.00	$0.00	$183,444.00
Clearing Accounts Transferred	$20,457.00	184	$10,913,873.00	$10,901,978.00	$8,562.00
Brown CT Long-Term Service Agreement	$1,410,566.00	107/232	$1,410,566.00	$0.00	$0.00
Valu. of Coal Contracts (Nov-10 to Dec-15) - PAA	$167,241.00	182.3	$167,241.00	$0.00	$0.00
0	$0.00	0	$0.00	$0.00	$0.00
0	$0.00	0	$0.00	$0.00	$0.00
TOTAL	$14,776,604.00		$21,702,529.00	$10,943,554.00	$4,017,629.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274)

Acct (a)	Balance Beg Yr (b)	Amt Acct 410.1 (c)	Amt Acct 411.1 (d)	Amt Acct 410.2 (e)	Amt Acct 411.2 (f)
Account 282					
Electric	$544,662,487.00	$264,478,892.00	$71,085,235.00	$0.00	$0.00
Gas	$166,504,147.00	$52,659,691.00	$18,708,363.00	$0.00	$0.00
Other (Define)					
Total	$711,166,634.00	$317,138,583.00	$89,793,598.00	$0.00	$0.00
Other (specify)					
TOTAL Acct 282	$711,166,634.00	$317,138,583.00	$89,793,598.00	$0.00	$0.00
Classification of Total					
Federal Income Tax	$634,595,824.00	$288,013,423.00	$77,983,248.00	$0.00	$0.00
State Income Tax	$76,570,810.00	$29,125,160.00	$11,810,350.00	$0.00	$0.00
Local Income tax					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274) (Part Two)

Acct (a)	Debit Adj Acct (g)	Debit Adj Amt (h)	Credit Adj. Acct (i)	Credit Adj. Amt (j)	Balance End Yr
Account 282					
Electric	254	$447,647.00	254	$605,578.00	$738,214,075.00
Gas	254	$150,704.00	254	$158,825.00	$200,463,596.00
Other (Define)					
Total		$598,351.00		$764,403.00	$938,677,671.00
Other (specify)					
TOTAL Acct 282		$598,351.00		$764,403.00	$938,677,671.00
Classification of Total					
Federal Income Tax		$517,313.00		$426,903.00	$844,535,589.00
State Income Tax		$81,038.00		$337,500.00	$94,142,082.00
Local Income tax					

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276)

Acct (a)	Balance Beg Yr (b)	Amt Acct 410.1 (c)	Amt Acct 411.1 (d)	Amt Acct 410.2 (e)	Amt Acct 411.2 (f)
Account 283					
Electric	$155,215,785.00	$35,480,828.00	$36,572,104.00	$0.00	$0.00
Gas	$26,448,646.00	$12,527,773.00	$15,657,501.00	$0.00	$0.00
Other					
Total	$181,664,431.00	$48,008,601.00	$52,229,605.00	$0.00	$0.00
Other (Specify)					
TOTAL (Acct 283)	$181,664,431.00	$48,008,601.00	$52,229,605.00	$0.00	$0.00
Classification of Total					
Federal Income Tax	$153,644,210.00	$41,356,991.00	$44,926,940.00	$0.00	$0.00
State Income Tax	$28,020,221.00	$6,651,610.00	$7,302,665.00	$0.00	$0.00
Local Income tax					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276) (Part Two)

Acct (a)	Debit Adj Acct (g)	Debit Adj Amt (h)	Credit Adj. Acct (i)	Credit Adj. Amt (j)	Balance End Yr
Account 283					
Electric	182	$108,745.00	182	$5,570.00	$154,021,334.00
Gas	190	$393,206.00	190	$20,140.00	$22,945,852.00
Other					
Total		$501,951.00		$25,710.00	$176,967,186.00
Other (Specify)					
TOTAL (Acct 283)		$501,951.00		$25,710.00	$176,967,186.00
Classification of Total					
Federal Income Tax		$428,495.00		$25,710.00	$149,671,476.00
State Income Tax		$73,456.00		$0.00	$27,295,710.00
Local Income tax					

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Other Regulatory Liabilities (Acct 254) (Ref Page: 278)

	Description and Purpose	Bal Beg Yr (b)	Debit Acct Credited (c)	Debits Amount (d)	Credits (e)	Balance End Yr (f)
	ASC 740 - Income Taxes	$37,308,800.00	190/282	$2,080,128.00	$690,868.00	$35,919,540.00
	Gas Supply Clause	$6,359,438.00	803	$18,141,117.00	$18,553,788.00	$6,772,109.00
	DSM Cost Recovery	$1,052,065.00	Various	$5,638,808.00	$8,631,662.00	$4,044,919.00
	Forward Starting Swap	$41,414,924.00	427	$1,433,704.00	$0.00	$39,981,220.00
	Fuel Adjustment Clause	$0.00	440-445	$1,378,859.00	$3,764,859.00	$2,386,000.00
	Off-System Sales Tracker	$0.00	440-445	$65,778.00	$118,112.00	$52,334.00
	MISO Exit Fee Refund	$686,188.00	575.7	$297,828.00	$2,798.00	$391,158.00
	0	$0.00		$0.00	$0.00	$0.00
	Coal Contracts (Nov-10 to Dec-16) - PAA	$25,385,051.00	186	$17,761,589.00	$0.00	$7,623,462.00
	OVEC Pwr Purchase Contract (Nov-10 to Mar-26)-PAA	$63,856,830.00	186	$5,756,807.00	$0.00	$58,100,023.00
	Emission Allowances (Nov-10 to Dec-40) - PAA	$1,341,711.00	186	$338,610.00	$158,865.00	$1,161,966.00
	Gas Line Tracker	$2,663,794.00	480-482	$2,663,794.00	$0.00	$0.00
Total		$180,068,801.00		$55,557,022.00	$31,920,952.00	$156,432,731.00

Note:
Due to software space limitations see footnote information provided in total in hard copy FERC Form 1.

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operating Revenues (Ref Page: 301)

	Rev for Transistion Current	Rev for Transistion Prev Yr	GRI and ACA Current Yr (d)	GRI and ACA Prev Yr (e)	other Current Yr (f)
Sales (480-484)	$309,035,503.00	$350,662,229.00	$0.00	$0.00	$0.00
Intracompany Transfers (485)					
Forfeited Discounts (487)	$1,233,219.00	$1,168,575.00	$0.00	$0.00	$0.00
Miscellaneous Service Revenues (488)	$87,601.00	$81,466.00	$0.00	$0.00	$0.00
Revenues from Transportaion of Gas of Others Through Gathering Facilities (489.1)					
Revenues from Transportaion of Gas of Others Through Transmission Facilities (489.2)	$1,393,237.00	$1,348,754.00	$0.00	$0.00	$0.00
Revenues from Transportaion of Gas of Others Through Distribution Facilities (489.3)	$7,363,416.00	$6,631,796.00	$0.00	$0.00	$0.00
Sales of Prod. Ext. from Natural Gas (490)					
Revenues from Natural Gas Proc. by Others (491)					
Incidental gasoline and Oil Sales (492)					
Rent from Gas Property (493)	$408,204.00	$389,526.00	$0.00	$0.00	$0.00
Interdepartmental Rents (494)					
Other Gas Revenues (495)	$164.00	$620.00	$0.00	$0.00	$0.00
Subtotal	$319,521,344.00	$360,282,966.00	$0.00	$0.00	$0.00
(Less) Provision for Rate Refunds (496)					
Total	$319,521,344.00	$360,282,966.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operating Revenues (Ref Page: 301) (Part Two)

	Rev for Transistion	Other Prev Yr (g)	Total Current Yr (h)	Total Prev Yr (i)	MCF Current Yr (h)	MCF Prev Yr (i)
Sales (480-484)	$309,035,503.00	$0.00	$309,035,503.00	$350,662,229.00	30,704,772	36,008,387
Intracompany Transfers (485)						
Forfeited Discounts (487)	$1,233,219.00	$0.00	$1,233,219.00	$1,168,575.00	0	0
Miscellaneous Service Revenues (488)	$87,601.00	$0.00	$87,601.00	$81,466.00	0	0
Revenues from Transportaion of Gas of Others Through Gathering Facilities (489.1)						
Revenues from Transportaion of Gas of Others Through Transmission Facilities (489.2)	$1,393,237.00	$0.00	$1,393,237.00	$1,348,754.00	1,934,902	1,134,982
Revenues from Transportaion of Gas of Others Through Distribution Facilities (489.3)	$7,363,416.00	$0.00	$7,363,416.00	$6,631,796.00	12,175,233	11,966,922
Sales of Prod. Ext. from Natural Gas (490)						
Revenues from Natural Gas Proc. by Others (491)						
Incidental gasoline and Oil Sales (492)						
Rent from Gas Property (493)	$408,204.00	$0.00	$408,204.00	$389,526.00	0	0
Interdepartmental Rents (494)						
Other Gas Revenues (495)	$164.00	$0.00	$164.00	$620.00	0	0
Subtotal	$319,521,344.00	$0.00	$319,521,344.00	$360,282,966.00	44,814,907	49,110,291
(Less) Provision for Rate Refunds (496)						
Total	$319,521,344.00	$0.00	$319,521,344.00	$360,282,966.00	44,814,907	49,110,291

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Rev From Transportation of Gas through Gathering Facilities (489.1) (Ref Page: 302)

Rate Schedule and Zone	Rev for Transition Costs	Rev for Transition Costs	Rev for GRI and ACA	Rev for GRI and ACA	Other Rev Current (f)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Rev From Transportation of Gas through Gathering Facilities (489.1) (Ref Page: 302) (Part Two)

Rate Schedule and Zone	Other Rev Previous (g)	Total Operating Rev	Total Operating Rev	MCF Current (j)	MCF Previous (k)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Rev From Transportation of Gas through Transmission Facilities (489.2) (Ref Page: 304)

Rate Schedule and Zone	Rev for Transition Costs	Rev for Transition Costs	Rev for GRI and ACA	Rev for GRI and ACA	Other Rev Current (f)
RATE FT/PADDY'S RUN	$1,393,237.00	$1,348,754.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Rev From Transportation of Gas through Transmission Facilities (489.2) (Ref Page: 304) (Part Two)

Rate Schedule and Zone	Other Rev Previous (g)	Total Operating Rev	Total Operating Rev	MCF Current (j)	MCF Previous (k)
RATE FT/PADDY'S RUN	$0.00	$1,393,237.00	$1,348,754.00	1,934,902	1,134,982

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Rev From Stroring Gas of Others (489.4) (Ref Page: 306)

Rate Schedule and Zone	Rev for Transition Costs	Rev for Transition Costs	Rev for GRI and ACA	Rev for GRI and ACA	Other Rev Current (f)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Rev From Stroring Gas of Others (489.4) (Ref Page: 306) (Part Two)

Rate Schedule and Zone	Other Rev Previous (g)	Total Operating Rev	Total Operating Rev	MCF Current (j)	MCF Previous (k)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Other Gas Revenues (495) (Ref Page: 308)

Description of Transaction	Revenues in Dollars
Miscellaneous- All Minor Items	$164.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
1. PRODUCTION EXPENSES		
A. Manufactured Gas Production		
Manufactured Gas Production		
B. Natural Gas Production		
B1. Natural Gas Produciton and Gathering		
Operation		
Operation Supervision and Engineering (750)		
Production Maps and Records (751)		
Gas Well Expenses (752)		
Field Lines Expenses (753)		
Field compressor Station Expenses (754)		
Field Compressor Station Fuel and Power (755)		
Field Measuring and Regulating Station Expenses (756)		
Purification Expenses (757)		
Gas Well Royalties (758)		
Other Expenses (759)		
Rents (760)		
18. Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (761)		
Maintenance of Structures and Improvements (762)		
Maintenance of Producing Gas Wells (763)		
Maintenance of Field Lines (764)		
Maintenance of Field Compressor Station Equipment (765)		
Maintenance of Field Measuring and Regulating Station Equipment (766)		
Maintenance of Purification Equipment (767)		
Maintenance of Drilling and Cleaning Equipment (768)		
Maintenance of Other Equipment (769)		
29. Total Maintenance		$0.00
Total Natural Gas Production and Gathering (Lines 18,29(		$0.00
B2. Products Extraction		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Operation		
Operation Supervision and Engineering (770)		
Operation Labor (771)		
Gas Shrinkage (772)		
Fuel (773)		
Power (774)		
Materials (775)		
Operation Supplies and Expenses (776)		
Gas Processed by Others (777)		
Royalties on Products Extracted (778)		
Marketing Expenses (779)		
Products Purchased for Resale (780)		
Variation in Products Inventory (781)		
(Less) Extracted Products Used by the Utility - Credit (782)		
Rents (783)		
47. Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (784)		
Maintenance of Structures and Improvements (785)		
Maintenance of Extraction and Refining Equipment (786)		
Maintenance of Pipe Lines (787)		
Maintenance of Extracted Products Storage Equipment (788)		
Maintenance of Compressor Equipment (789)		
Maintenance of Gas Measuring and Regulating Equipment (790)		
Maintenance of Other Equipment (791)		
57. Total Maintenance		$0.00
58. Total Products Extraction (Lines 47 and 57)		$0.00
C. Exploration and Development		
Operation		
Delay Rentals (795)		
Nonproductive Well Drilling (796)		
Abandoned Leases (797)		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Other Exporation (798)		
65. Total Exploration and Development		$0.00
D. Other Gas Supply Expenses		
Operation		
Natural Gas Well Head Purchases (800)		
Natural Gas Well Head Purchases, Intracompany Transfers (800.1)		
Natural Gas Field Line Purchases (801)		
Natural Gas Gasoline Plant Outlet Purchases (802)		
Natural Gas Transmission Line Purchases (803)	$133,849,235.00	$201,868,890.00
Natural Gas City Gate Purchases (804)		
Liquified Natural Gas Purchases (804.1)		
Other Gas Purchases (805)		
(Less) Purchases Gas Cost Adjustments (805.1)		
77. Total Purchased Gas	$133,849,235.00	$201,868,890.00
78. Exchange Gas (806)	($2,599,873.00)	$259,201.00
Purchased Gas Expense		
Well Expense - Purchased Gas (807.1)		
Operation of Purchased Gas Measuring Stations (807.2)		
Maintenance of PUrchased Gas Measuring Stations (807.3)		
Purchased Gas Calculations Expenses (807.4)		$7,918.00
Other Purchased Gas Expenses (807.5)	$807,713.00	$780,964.00
85. Total Purchased Gas Expenses	$807,713.00	$788,882.00
Gas Withdrawn from Storage - Debit (808.1)	$49,162,585.00	$47,697,441.00
(Less) Gas Delivered to Storage (Credit) (808.2)	$38,769,827.00	$56,222,456.00
Withdrawals of Liquefied natural Gas for Processing - Debit (809.1)		
(Less) Delieveries of Natural Gas for Processing- Credit (809.2)		
Gas used in Utility Operation - Credit		
91. Gas Used for Compressor Station Fuel - Credit (810)	($646,000.00)	($504,154.00)
92..Gas Used for Products Extraction - Credit (811)		
93..Gas Used for Other Utility Operations - Credit (812)	($178,781.00)	($136,549.00)

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
94. Total Gas Used in Utility Operations - Credit (91-93)	($824,781.00)	($640,703.00)
95. Other Gas Supply Expenses (813)		
97. Total Other Gas Supply Exp (77,78,85,86-89,94,95)	$141,625,052.00	$193,751,255.00
Total Production Expenses (3,30,58,65,96)	$141,625,052.00	$193,751,255.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
A. Underground Storage Expenses		
Operation		
Operation Supervision and Engineering (814)	$678,309.00	$542,293.00
Maps and Records (815)		
Wells Expenses (816)	$357,834.00	$352,513.00
Lines Expenses (817)	$770,193.00	$746,336.00
Compressor Station Expenses (818)	$2,393,159.00	$1,966,817.00
Compressor Station Fuel and Power (819)	$646,000.00	$507,290.00
Measuring and Regulating Station Expenses (820)		
Purification Expenses (821)	$1,449,442.00	$1,327,834.00
Exploration and Development (822)		
Gas Losses (823)	$1,690,061.00	$1,920,523.00
Other Expenses (824)	$14,508.00	$12,128.00
Storage well Royalties (825)	$237,295.00	$97,347.00
Rents (826)		($359.00)
114. Total Operation	$8,236,801.00	$7,472,722.00
Maintenance		
Maintenance Supervision and Engineering (830)	$463,550.00	$433,740.00
Maintenance of Structures and Improvements (831)		
Maintenance of Reservoirs and Wells (832)	$862,913.00	$724,453.00
Maintenance of Lines (833)	$129,836.00	$154,144.00
Maintenance of Compressor Station Equipment (834)	$841,137.00	$689,147.00
Maintenance of Measuring and Regulating Station Equipment (835)	$51,355.00	$23,393.00
Maintenance of Purification Equipmetn (836)	$979,489.00	$870,717.00
Maintenance of Other Equipment (837)	$91,905.00	$91,597.00
124. Total Maintenance	$3,420,185.00	$2,987,191.00
Total Underground Storage (Lines 114 and 124)	$11,656,986.00	$10,459,913.00
B. Other Storage Expenses		
Operation		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Operation Supervision and Engineering (840)		
Operation Labor and Expenses (841)		
Rents (842)		
Fuel (842.1)		
Power (842.2)		
Gas Losses (842.3)		
134. Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (843.1)		
Maintenance of Structures and Improvements (843.2)		
Maintenance of Gas Holders (843.3)		
Maintenance of Purification Equipment (843.4)		
Maintenance of Liquefaction Equipment (843.5)		
Maintenance of Vaporizing Equipment (843.6)		
Maintenance of Compressor Equipment (843.7)		
Maintenance of Measuring and Regulating Equipment (843.8)		
Maintenance of Other Equipment (843.9)		
145. TOTAL Maintenance		$0.00
Total Other Storage Expenses (Lines 134 and 145)		$0.00
C. Liquefied Natural Gas Terminaling and Processing Expenses		
Operation		
Operation Supervision and Engineering (844.1)		
LNG Processing Terminal Labor and Expenses (844.2)		
Liquefaction Processing Labor and Expenses (844.3)		
Liquefaction Transportaion Labor and Expenses (844.4)		
Measuring and Regulating Labor and Expenses (844.5)		
Compressor Station Labor and Expenses (544.6)		
Communication System Expenses (844.7)		
System Control and Load Dispatching (844.8)		
Fuel (845.1)		
Power (845.2)		
Rents (845.3)		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Demurrage Charges (845.4)		
(Less) Wharfage Receipts - Credit (845.5)		
Processing Liquefied or Vaporized Gas by Others (845.6)		
Gas Losses (846.1)		
Other Expenses (846.2)		
Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (847.1)		
Maintenance of Structures and Improvements (847.2)		
Maintenance of LNG Processing Terminal equipment (847.3)		
Maintenance of LNG Transportation Equipment (847.4)		
Maintenance of Measuring and Regulating Equipment (847.5)		
Maintenance of Compressor Station Equipment (847.6)		
Maintenance of Communication Equipment (847.7)		
Maintenance of Other Equipment (847.8)		
175. Total Maintenance		$0.00
176. Total Liquified Nat Gas Terminaling and Proc Exp (Lines 165 and 175)		$0.00
177. Total Natural Gas Storage (Lines 125,146 and 176)	$11,656,986.00	$10,459,913.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
3. TRANSMISSION EXPENSES		
Operation		
Operation Supervision and Engineering (850)	$496,722.00	$328,917.00
System Control and Load Dispatching (851)	$402,192.00	$351,277.00
Communication System Expenses (852)		$1,000.00
Compressor Station labor and Expenses (853)		
Gas for Compressor Station Fuel (854)		
Other Fuel and Power for Compressor Stations (855)		
Mains Expenses (856)	$648,586.00	$396,888.00
Measuring and Regulating Stations Expenses (857)		
Transmission and Compression of Gas by Others (858)		
Other Expenses (859)		
Rents (860)	$30,565.00	$10,080.00
191. Total Operation	$1,578,065.00	$1,088,162.00
Maintenance		
Maintenance Supervision and Engineering (861)		
Maintenance of Structures and Improvements (862)		
Maintenance of Mains (863)	$1,852,205.00	$991,883.00
Maintenance of Compressor Station Equipment (864)		
Maintenance of Measuring and Regulating Station Equipment (865)		
Maintenance of Communication Equipment (866)		
Maintenance of Other Equipment (867)		
200. Total Maintenance	$1,852,205.00	$991,883.00
201. Total Transmission Expenses (Total 191 and 200)	$3,430,270.00	$2,080,045.00
4. DISTRIBUTION EXPENSES		
Operation		
Operation Supervision and Engineering (870)		
Distribution Load Dispatching (871)	$586,498.00	$509,873.00
Compressor Station Labor and Expenses (872)		
Compressor Station Fuel and Power (873)		
Mains and Services Expenses (874)	$3,009,171.00	$2,614,272.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Measuring and Regulating station Expenses - General (875)	$1,194,476.00	$963,851.00
Measuring and Regulating Station Expenses - Industrial (876)	$399,444.00	$322,953.00
Measuring and Regulating Station Expenses - City Gas Check Station (877)	$173,992.00	$197,272.00
Meter and House Regulator Expenses (878)	$1,912,623.00	$1,923,886.00
Customer Installations Expenses (879)	$159,276.00	$210,175.00
Other Expenses (880)	$3,175,393.00	$2,203,380.00
Rents (881)	$15,573.00	$10,787.00
216. Total Operation	$10,626,446.00	$8,956,449.00
Maintenance		
Maintenance Supervision and Engineering (885)		
Maintenance of Structures and Improvements (886)	$8,537.00	$29,457.00
Maintenance of Mains (887)	$9,794,835.00	$10,748,523.00
Maintenance of Compressor Station Equipment (888)		
Maintenance of Measuring and Regulating Station Equipment - General (889)	$126,349.00	$132,725.00
Maintenance of Measuring and Regulating Station Equipment - Industrial (890)	$313,324.00	$310,452.00
Maintenance of Measuring and Regulating Station Equipment - City Gate Check Station (891)	$415,461.00	$560,116.00
Maintenance of Services (892)	$3,034,613.00	$2,844,746.00
Maintenance of Meters and House Regulators (893)		
Maintenance of Other Equipment (894)	$158,649.00	$145,101.00
228. Total Maintenance	$13,851,768.00	$14,771,120.00
229. Total Distribution Expenses (Lines 216 and 228)	$24,478,214.00	$23,727,569.00
5. CUSTOMER ACCOUNTS EXPENSES		
Operation		
Supervision (901)	$994,758.00	$886,316.00
Meter Reading Expenses (902)	$1,957,732.00	$1,946,365.00
Customer Records and Collections Expenses (903)	$4,815,982.00	$4,542,555.00
Uncollectible Accounts (904)	$295,466.00	$1,090,481.00
Miscellaneous Customer Accounst Expenses (905)	($572.00)	$19,984.00
237. Total Customer Accounts Expenses	$8,063,366.00	$8,485,701.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
Operation		
Supervision (907)	$61,344.00	$66,408.00
Customer Assistance Expenses (908)	$3,488,183.00	$2,938,152.00
Informational and Instructional Expenses (909)	$188,580.00	$102,753.00
Miscellaneous Customer Service and Informational Expenses (910)	$132,864.00	$133,404.00
244. Total Customer Service and Informational Expenses	$3,870,971.00	$3,240,717.00
7. SALES EXPENSES		
Operation		
Supervision (911)		
Demonstrating and Selling Expenses (912)		
Advertising Expenses (913)	$203,284.00	$14,985.00
Miscellaneous Sales Expenses (916)		
251. TOTAL Sales Expenses	$203,284.00	$14,985.00
8. ADMINISTRATIVE AND GENERAL EXPENSES		
Operation		
Administrative and General Salaries (920)	$6,931,034.00	$6,352,033.00
Office Supplies and Expenses (921)	$1,517,739.00	$1,487,757.00
(Less) Administrative Expenses Transferred - Credit (922)	$802,466.00	$724,504.00
Outside Services Employed (923)	$3,527,179.00	$3,254,522.00
Property Insurance (924)	$48,524.00	$26,005.00
Injuries and Damanges (925)	$737,920.00	$834,180.00
Employee Pensions and benefits (926)	$8,713,078.00	$6,726,971.00
Franchise Requirements (927)		$470,333.00
Regulatory Commission Expenses (928)	$152,301.00	$104,875.00
(Less) Duplicate Charges - Credit (929)	$502,396.00	$443,292.00
General Advertising Expenses (930.1)	$44,369.00	$334,953.00
Miscellaneous General Expenses (930.2)	$403,836.00	$373,259.00
Rents (931)	$305,748.00	$399,034.00
267. Total Operation	$21,076,866.00	$19,196,126.00
Maintenance		

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
269. Maintenance of General Plant (935)	$319,970.00	$382,429.00
270. Total Administrative and General (Total 267 and 269)	$21,396,836.00	$19,578,555.00
Total Gas O and M Expenses (Total Lines 97,177,201,229,237,244,251 and 270)	$214,724,979.00	$261,338,740.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Exchange and Imbalance Transactions (Ref Page: 328)

	Zone/Rate Schedule	Gas Received Amount (b)	Gas Received MCF (c)	Gas Delivered Amount (d)	Gas Delivered MCF (e)
Total					

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Gas Used in Utility Operations (Ref Page: 331)

	Purpose (a)	Acct Charged (b)	Natural Gas Used MCF (c)	Natural Gas Amount of Credit (d)	Manufactured Gas MCF (e)	Manufactured Gas Amount of Credit (f)
Gas Used for Compressor Station Fuel - Credit (810)		819	151,988	$646,000.00	0	$0.00
Gas Used For Products Extration - Credit (811)						
Gas Shrinkage and Other Usage in Respondent`s Own Processing						
Gas Shrinkage, etc. for Respondent`s Gas Processed by Others						
Gas Used for Other Utility Operations - Credit (812)						
(Report seperately each principal use. Group minor uses.)						
	City Gate Station	875,877	9,969	$41,775.00	0	$0.00
	Gas used in Electric Generation	547	21,063	$82,407.00	0	$0.00
	Various	Various	12,904	$54,599.00	0	$0.00
Total			195,924	$824,781.00	0	$0.00

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Transmission and Compression of Gas by Others (858) (Ref Page: 332)

Name of Company and Desc. of	* (b)	Amount of Payment (c)	MCF of Gas (d)

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Other Gas Supply Expenses (813) (Ref Page: 334)

Description (a)	Amount (b)
No activity	$0.00
Total	

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Miscellaneous General Expenses (Acct 930.2) (Ref Page: 335)

Description		Amount
Industry association dues		$38,150.00
Experimental and general research expenses.		
a. Gas Research Institute (GRI)		
b. Other		
Publishing and distributing information and reports to stockholders, trustee, registrar and transfer agent fees and expenses and other expenses		
Other		
	Swap Termination Amortization	$81,580.00
	American Gas Association Amortization	$178,069.00
	Miscellaneous	$106,037.00
Total		$403,836.00

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Depreciation, Depletion and Amortization of Gas Plant (403,403.1,404.1,404.2,404.3,405) (Ref Page: 336)

	Depreciation 403 (b)	Depreciation Exp	404.1 (d)	404.2 (e)	404.3 (f)	405 (g)	Total (h)
Intangible Plant	$0.00	$0.00	$0.00	$0.00	$41.00	$0.00	$41.00
Production Plant, manufactured gas							
Production and gathering plant, natural gas							
Products extraction plant							
Underground gas storage plant	$2,675,647.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,675,647.00
Other storage plant							
Base load LNG terminaling and processing plant							
Transmission plant	$388,500.00	$0.00	$0.00	$0.00	$0.00	$0.00	$388,500.00
Distribution plant	$22,123,112.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22,123,112.00
General Plant	$329,316.00	$0.00	$0.00	$0.00	$0.00	$0.00	$329,316.00
Common plant - gas	$3,588,543.00	$0.00	$0.00	$0.00	$3,199,280.00	$0.00	$6,787,823.00
Other							
Total	$29,105,118.00	$0.00	$0.00	$0.00	$3,199,321.00	$0.00	$32,304,439.00

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Depreciation, Depletion and Amortization of Gas Plant (cont) (Ref Page: 338)

	Functional Classification (a)	Plant Bases (thousands) (b)	Applied Depr or Amort Rates (c)
Production and Gathering Plant			
Offshore			
Onshore			
	Underground Storage Plant	138,923	2
Underground Gas Storage Plant			
Transmission Plant			
Offshore			
Onshore			
	Transmission Plant	52,773	1
General Plant			
	General Plant	7,207	3
	Distribution Plant	818,309	3

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Particulars Concerning Cetrain Income Deductions and Interest Charges Accounts (Ref Page: 340)

Item (a)	Amount (b)
Account 426.1 - Donations	$0.00
Association of Community Ministries	$412,500.00
Spalding University	$250,000.00
Various	$3,309,651.00
Total Account 426.1	$3,972,151.00
Account 426.3 - Penalties	$6,570.00
Total Account 426.3	$6,570.00
Account 426.4- Civic, Political & Related Activity	$570,732.00
Total Account 426.4	$570,732.00
Account 426.5 - Other Deductions	$2,451,011.00
Total Account 426.5	$2,451,011.00
Account 430-Interest on Debt to Associated Company	$0.00
LG&E and KU Energy LLC	$0.00
Kentucky Utilities Company	$5,661.00
Total Account 430	$5,661.00
Account 431 - Other Interest Expense	$0.00
Financial Liabilities	$1,010,115.00
Customer Deposits - 6% Interest Rate	$31,561.00
Interest on Rates Refund	$8,517.00
DSM Cost Recovery	$2,040.00
Interest on Tax Deficiencies	$1.00
Other	$1,031,156.00
Total Account 431	$2,083,390.00

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Regulatory Commission Expenses (928) (Ref Page: 350)

Description (a)	Assessed by Reg Commission (b)	Expenses of the Utility (c)	Total Expenses (d)	Deferred in 182.3 Beg of Yr (e)	Expenses Incurred Charged to Department
FERC	$0.00	$0.00	$0.00	$0.00	
Annual Charge	$350,592.00	$0.00	$350,592.00	$0.00	Electric
Administrative Charge. Project #289	$188,645.00	$0.00	$188,645.00	$0.00	Electric
	$0.00	$0.00	$0.00	$0.00	
KPSC	$0.00	$0.00	$0.00	$0.00	
2014 Rate Case - Electric (Jul-15 to Jun-18)	$0.00	$189,600.00	$189,600.00	$753,342.00	Electric
2014 Rate Case - Gas (Jul-15 to Jun-18)	$0.00	$47,400.00	$47,400.00	$188,335.00	Gas
	$0.00	$0.00	$0.00	$0.00	
2012 Rate Case - Electric (Jan-13 to Dec-15)	$0.00	$298,214.00	$298,214.00	$298,214.00	Electric
2012 Rate Case - Gas (Jan-13 to Dec-15)	$0.00	$94,960.00	$94,960.00	$94,960.00	Gas
	$0.00	$0.00	$0.00	$0.00	
2011 Gen Mgmt Audit - Elec (Jan-13 to Dec-15)	$0.00	$30,527.00	$30,527.00	$30,527.00	Electric
2011 Gen Mgmt Audit - Gas (Jan-13 to Dec-15)	$0.00	$9,941.00	$9,941.00	$9,941.00	Gas
	$539,237.00	$670,642.00	$1,209,879.00	$1,375,319.00	

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Regulatory Commission Expenses (928) (Ref Page: 350) (Part Two)

Description (a)	Expenses Incurred Charged to Acct (g)	Expenses Incurred Charged to Amount	Expenses Incurred Deferred to 182.3 (i)	Amortized Contra Acct (j)	Amortized Amt (k)	Deferred in 182.3 End of Yr (l)
FERC		$0.00	$0.00		$0.00	$0.00
Annual Charge	928	$350,592.00	$0.00		$0.00	$0.00
Administrative Charge. Project #289	928	$188,645.00	$0.00		$0.00	$0.00
		$0.00	$0.00		$0.00	$0.00
KPSC		$0.00	$0.00		$0.00	$0.00
2014 Rate Case - Electric (Jul-15 to Jun-18)	928	$189,600.00	$383,968.00	928	$189,600.00	$947,710.00
2014 Rate Case - Gas (Jul-15 to Jun-18)	928	$47,400.00	$95,992.00	928	$47,400.00	$236,927.00
		$0.00	$0.00		$0.00	$0.00
2012 Rate Case - Electric (Jan-13 to Dec-15)	928	$298,214.00	$0.00	928	$298,214.00	$0.00
2012 Rate Case - Gas (Jan-13 to Dec-15)	928	$94,960.00	$0.00	928	$94,960.00	$0.00
		$0.00	$0.00		$0.00	$0.00
2011 Gen Mgmt Audit - Elec (Jan-13 to Dec-15)	928	$30,527.00	$0.00	928	$30,527.00	$0.00
2011 Gen Mgmt Audit - Gas (Jan-13 to Dec-15)	928	$9,941.00	$0.00	928	$9,941.00	$0.00
		$1,209,879.00	$479,960.00		$670,642.00	$1,184,637.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Distribution of Salaries and Wages - Electric (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Electric			
Operation			
3. Production	$24,560,753.00	$5,526,012.00	$30,086,765.00
4. Transmission	$2,755,115.00	$879,836.00	$3,634,951.00
5. Distribution	$8,216,253.00	$2,346,292.00	$10,562,545.00
6. Customer Accounts	$4,111,598.00	$1,347,761.00	$5,459,359.00
7. Customer Service and Informational	$744,996.00	$263,278.00	$1,008,274.00
8. Sales	$0.00	$0.00	$0.00
9. Administrative and General	$18,918,444.00	$4,454,492.00	$23,372,936.00
10. Total Operation	$59,307,159.00	$14,817,671.00	$74,124,830.00
Maintenance			
12. Production	$10,527,971.00	$2,702,001.00	$13,229,972.00
13. Transmission	$501,545.00	$146,310.00	$647,855.00
14. Distribution	$2,577,698.00	$590,773.00	$3,168,471.00
15. Administrative and General	$427,479.00	$121,789.00	$549,268.00
16. Total Maint	$14,034,693.00	$3,560,873.00	$17,595,566.00
Total Operation and Maintenance			
18. Total Production (Lines 3 and 12)	$35,088,724.00	$8,228,013.00	$43,316,737.00
19. Total Transmission (Lines 4 and 13)	$3,256,660.00	$1,026,146.00	$4,282,806.00
20. Total Distribution (Lines 5 and 14)	$10,793,951.00	$2,937,065.00	$13,731,016.00
21. Customer Accounts (Transcribe from Line 6)	$4,111,598.00	$1,347,761.00	$5,459,359.00
22. Customer Service and Informational (Transcribe from Line 7)	$744,996.00	$263,278.00	$1,008,274.00
23. Sales (Transcribe from Line 8)	$0.00	$0.00	$0.00
24. Administrative and Generatl (Lines 9 and 15)	$19,345,923.00	$4,576,281.00	$23,922,204.00
25. Total Oper. and Maint. (Lines 18-24)	$73,341,852.00	$18,378,544.00	$91,720,396.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Distribution of Salaries and Wages - Gas (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Gas			
Operation			
28. Production -- Manufactured Gas	$0.00	$0.00	$0.00
29. Production -- Nat. Gas (Including Expl and Dev.)	$0.00	$0.00	$0.00
20. Other Gas Supply	$567,263.00	$166,901.00	$734,164.00
31. Storage, LNG Terminaling and Processing	$2,062,326.00	$553,408.00	$2,615,734.00
32. Transmission	$904,800.00	$276,635.00	$1,181,435.00
33. Distribution	$3,694,058.00	$1,679,827.00	$5,373,885.00
34. Customer Accounts	$3,364,035.00	$1,102,714.00	$4,466,749.00
35. Customer Service and Informational	$265,190.00	$91,592.00	$356,782.00
36. Sales	$0.00	$0.00	$0.00
37. Administrative and General	$5,231,147.00	$1,070,920.00	$6,302,067.00
38. Total Operation	$16,088,819.00	$4,941,997.00	$21,030,816.00
Maintenance			
40. Production -- Manufactured Gas	$0.00	$0.00	$0.00
41. Production -- Natural Gas	$0.00	$0.00	$0.00
42. Other Gas Supply	$0.00	$0.00	$0.00
43. Storage, LNG Terminaling and Processing	$1,462,982.00	$406,070.00	$1,869,052.00
44. Transmission	$389,102.00	$115,038.00	$504,140.00
45. Distribution	$5,317,173.00	$641,888.00	$5,959,061.00
46. Administrative and General	$183,206.00	$52,196.00	$235,402.00
47. Total Maint	$7,352,463.00	$1,215,192.00	$8,567,655.00
Total Operation and Maintenance			
50. Total Production -- Manufactured Gas (Lines 28 and 40)	$0.00	$0.00	$0.00
51. Total Production -- Natural Gas (Lines 29 and 41)	$0.00	$0.00	$0.00
52. Total Other Gas Supply (Lines 30 and 42)	$567,263.00	$166,901.00	$734,164.00
53. Total Storage LNG Terminaling and Processing (Lines 31 and 43)	$3,525,308.00	$959,478.00	$4,484,786.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Distribution of Salaries and Wages - Gas (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
54. Total Transmission (Lines 32 and 44)	$1,293,902.00	$391,673.00	$1,685,575.00
55. Total Distribution (Lines 33 and 45)	$9,011,231.00	$2,321,715.00	$11,332,946.00
56. Customer Accounts (Transcribe Line 34)	$3,364,035.00	$1,102,714.00	$4,466,749.00
57. Customer Service and Informational (Transcribe Line 35)	$265,190.00	$91,592.00	$356,782.00
58. Sales (Transcribe Line 36)	$0.00	$0.00	$0.00
59. Administrative and General (Line 37 + 46)	$5,414,353.00	$1,123,116.00	$6,537,469.00
60. Total Operation and Maint (Lines 50-59)	$23,441,282.00	$6,157,189.00	$29,598,471.00
Other Utility Departments			
62. Operation and Maintenance	$0.00	$0.00	$0.00
63. Total All Utility Dept (Lines 25,60,62)	$96,783,134.00	$24,535,733.00	$121,318,867.00

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Distribution of Salaries and Wages - Utility Plant (Ref Page: 356)

	Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Utility Plant				
Construction (By Utility Departments)				
66. Electric Plant		$12,275,422.00	$11,737,736.00	$24,013,158.00
67. Gas Plant		$5,819,800.00	$4,273,104.00	$10,092,904.00
68. Other	Common Utility Plant	$2,657,598.00	$1,023,963.00	$3,681,561.00
69. Total Construction		$20,752,820.00	$17,034,803.00	$37,787,623.00
70. Plant Removal (By Utility Departments)				
71. Electric Plant		$1,578,768.00	$1,179,541.00	$2,758,309.00
72. Gas Plant		$280,721.00	$347,974.00	$628,695.00
73. Other	Common Utility Plant	$0.00	$21.00	$21.00
74. Total Plant Removal		$1,859,489.00	$1,527,536.00	$3,387,025.00
75. Other Accounts				
	Accounts Receivable (work done for others)	$11,127,366.00	$2,941,769.00	$14,069,135.00
	Miscellaneous Deferred Debits	$77,095.00	$20,879.00	$97,974.00
	Civic, Political & Related Activities & Other	$622,310.00	$78,888.00	$701,198.00
	Non-jurisdictional	$2,289,312.00	$617,634.00	$2,906,946.00
76. Total Other Accounts		$14,116,083.00	$3,659,170.00	$17,775,253.00
77. Total Salaries and Wages		$133,511,526.00	$46,757,242.00	$180,268,768.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Charges for Outside Professional and Other Consultative Services (Ref Page: 358)

Description (a)	* (b)	Amount (2)
ABEL CONSTRUCTION COMPANY INC		$336,162.00
BRATCHER SERVICES LLC		$962,946.00
ENSITE USA INC		$883,382.00
FISHEL CO		$919,092.00
HAYES TESTING LABORATORY INC		$263,657.00
HONEYWELL INDUSTRY INTERNATIONAL INC		$288,697.00
INFRASOURCE CONSTRUCTION LLC		$439,478.00
KENTUCKIANA TRAFFIC AND PATROL SERVICES LLC		$2,327,951.00
MILLER PIPELINE CORP		$24,846,174.00
OLAMETER CORPORATION		$1,575,280.00
OPOWER INC		$336,802.00
OPS PLUS INC		$1,519,453.00
PRECISION ENERGY SERVICES INC		$290,127.00
PREMIER ENERGY SERVICES LLC		$3,859,642.00
ROSEN USA		$274,542.00
SAMAC PAINTING INC		$2,294,236.00
SCHARDEIN MECHANICAL		$1,262,614.00
SCOPPECHIO		$665,542.00
SEEL LLC		$903,792.00
SERCO INC		$324,334.00
SOLAR TURBINES INC		$465,437.00
SOUTHERN PIPELINE CONST CO		$8,916,651.00
STEVEN L PAALZ		$440,664.00
STOLL CONSTRUCTION AND PAVING CO INC		$2,883,994.00
SURVEYS AND ANALYSIS INC		$2,749,623.00
TSI PAVING INC		$668,095.00
USIC LOCATING SERVICES INC		$1,838,825.00
XEROX CORP		$294,270.00
OTHER		$9,754,003.00
TOTAL		$72,585,465.00
		$0.00

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Compressor Stations (Ref Page: 508)

Name of Station and	Number of Units (b)	Certified Horsepower (c)	Plant Cost (d)	Fuel or Power (e)	Fuel or Power Type
Magnolia Compressor Station	7	11,560	$31,656,904.00	$448,262.00	Natural Gas
Muldraugh Compressor Station	9	9,545	$32,599,003.00	$55,781.00	Natural Gas
Field Compressor Stations for Self-Use to	0	0	$0.00	$0.00	
Recover Underground Storage Gas	0	0	$0.00	$0.00	
Doe-Run-Brandenburg, Ky. and Laconia, In.	9	1,000	$3,837,190.00	$153,023.00	See Footnote
Muldraugh-Muldraugh, Ky.	1	30	$114,905.00	$5,922.00	Electricity
Center Compressor Station	2	2,070	$14,610,392.00	$141,957.00	Natural Gas

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Compressor Stations (Ref Page: 508) (Part Two)

Name of Station and	Other (f)	Gas for Comp Fuel MCF	Total Comp Hours	Comp operating at Time	Date of Station Peak (j)
Magnolia Compressor Station	$2,066,860.00	107,160	8,411	7	1/7/2015
Muldraugh Compressor Station	$3,529,765.00	132,057	1,101	4	2/18/2015
Field Compressor Stations for Self-Use to	$0.00	0	0	0	
Recover Underground Storage Gas	$0.00	0	0	0	
Doe-Run-Brandenburg, Ky. and Laconia, In.	$1,472,294.00	9,029	14,750	0	
Muldraugh-Muldraugh, Ky.	$0.00	0	1,713	0	
Center Compressor Station	$0.00	0	3,260	2	1/7/2015

Note:
Doe Run-Brandenburg, Ky. and Laconia, In.,column (b):
Of the total 9 compressors only 3 were in operation in 2015, with a total of 665 horsepower, column (c).

Doe Run-Brandenburg, Ky. and Laconia, In.,column (e):
Of the total amount, $35,660.94 is gas and $117,361.97 is electricity.

Doe Run-Brandenburg, Ky. and Laconia, In.,column (j):
Station Peak not applicable for field compressors.

Muldraugh – Muldraugh, Ky., column(j):
Station Peak not applicable for field compressors.

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Gas Storage Projects (Ref Page: 512)

	Gas Belonging to Respondent MCF (b)	Gas Belonging to Others MCF (c)	Total MCF (d)
Storage Operations (in MCF)			
Gas Delivered to Storage			
January	13,017	0	13,017
February	0	0	0
March	9,043	0	9,043
April	0	0	0
May	7,091	0	7,091
June	1,355,602	0	1,355,602
July	2,793,229	0	2,793,229
August	3,001,372	0	3,001,372
September	2,826,217	0	2,826,217
October	1,767,185	0	1,767,185
November	268,571	0	268,571
December	94,529	0	94,529
Total	12,135,856	0	12,135,856
Gas Withdrawn from Storage			
January	3,694,706	0	3,694,706
February	2,917,355	0	2,917,355
March	1,561,647	0	1,561,647
April	963,270	0	963,270
May	318,641	0	318,641
June	717	0	717
July	675	0	675
August	583	0	583
September	645	0	645
October	1,027	0	1,027
November	174,732	0	174,732
December	1,860,544	0	1,860,544
Total	11,494,542	0	11,494,542

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Gas Storage Projects (cont) (Ref Page: 513)

	Total Amount (b)	Date
Storage Operations		
Top or Working Gas End of Year	12,333,765	
Cushion Gas (Including native gas)	10,810,000	
Total Gas in Reservoir	23,143,765	
Certified Storage Capacity	25,900,000	
Number of Injection - Withdrawal Wells	326	
Number of Obsevation Wells	124	
Maximum Days Withdrawal from Storage	182,310	
Date of Maximum Days Withdrawal		1/8/2015
LNG Terminal Companies (MCF)	0	
Number of Tanks	0	
Capacity of Tanks	0	
LNG Volume	0	
Received at Ship Rail	0	
Transferred to Tanks	0	
Withdrawn from Tanks	0	
Boil Off Vaporization Loss	0	

Note:
Cushion gas includes non-current base gas of 2,930,000 Mcf (Account 117).

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Transmission Lines (Ref Page: 514)

Designation of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
Western Kentucky Line		49
Magnolia Line		132
Calvary Line		57
Elder Park Line		27
Total		265

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Transmission System Peak Deliveries (Ref Page: 518)

	Description	MCF Gas to Interstate Pipelines (b)	MCF Gas to Others (c)	Total (d)
Section A: Single Day Peak Deliveries				
Date	January 18, 2016			
Volumes of Gas Transported				
No-Notice Transportation		0	51,000	0
Other Firm Transportation		0	87,000	0
Interruptible Transportation		0	0	0
Other (Describe)				
	End-Use Transportation	0	75,000	0
Total		0	213,000	0
Volumes of gas Withdrawn form Storage under Storage Contracts				
No-Notice Storage		0	40,000	0
Other Firm Storage		0	0	0
Interruptible Storage		0	0	0
Other (Describe)				
Total		0	40,000	0
Other Operational Activities				
Gas Withdrawn from Storage for System Operations		0	178,000	0
Reduction in Line Pack		0	0	0
Other (Describe)				
Total		0	178,000	0
Section B: Consecutive Three-Day Peak Deliveries				
Dates:	January 17, 18, 19, 2016			
Volumes of Gas Transported				
No-Notice Transportation		0	154,000	0
Other Firm Transportation		0	260,000	0
Interruptible Transportation				
Other (Describe)				
	End-Use Transportation	0	223,000	0

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Transmission System Peak Deliveries (Ref Page: 518)

Description	MCF Gas to Interstate Pipelines (b)	MCF Gas to Others (c)	Total (d)
Total	0	637,000	0
Volumes of Gas Withdrawn from Storage under Storage Contacts			
No-Notice Storage	0	120,000	0
Other Firm Storage			
Interruptible Storage			
Other (Describe)			
Total	0	120,000	0
Other Operational Activities			
Gas Withdrawn from Storage for System Operations	0	438,000	0
Reduction in Line Pack			
Other (Describe)			
Total	0	438,000	0

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Auxiliary Peaking Facilities (Ref Page: 519)

Location (a)	Type (b)	Max Daily Delivery Capacity MCF (c)	Cost of Facility (d)	Operated on Date Highest Trans Peak Del? (yes/no)
Muldraugh - Meade County, KY	Underground Storage	180,910	$36,291,284.00	Yes
Doe Run - Meade Co., KY and Harrison Co., IN	Underground Storage	60,000	$20,140,007.00	Yes
Magnolia - Green, Hart and Larue Counties, KY	Underground Storage	68,500	$50,737,639.00	Yes
Center - Metcalfe, Green and Barren Counties, KY	Underground Storage	21,320	$26,593,017.00	Yes
Canmer - Hart and Green Counties, KY		0	$430,631.00	No
Flint Hill - Hardin County, KY		0	$273,275.00	No
Total		312,820	$134,465,853.00	

Note:
Gas fields at Canmer and Flint Hill have been retired. These facilities are currently used in other gas-system operations.

Total Max Daily Delivery Capacity of 312,820 Mcf does not represent the combined Max Daily Delivery Capacity for each location. This value has been estimated due to pipeline and compressor capacity and multiple fields discharging into one pipeline system.

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Gas Account - Natural Gas (Ref Page: 520)

Description		Amt MCF
GAS RECEIVED		
Gas Purchases (800-805)		33,070,579
Gas of Others received for Gathering (ref pg 303) (489.1)		
Gas of Others Received for Transmission (Ref pg 305) (489.2)		
Gas of Others Received for Distrubution (ref pg 301) (489.3)		14,372,297
Gas of Others Received for Contract Storage (Ref Pg 307) (489.4)		
Exchanged Gas Received from Others (Ref Pg 328) (806)		3,097,465
Gas Received as Imbalances (Ref Pg 328) (806)		
Receipts of Respondent`s Gas Transported by Others (Ref pg 332) (858)		
Other Gas Withdrawn from Storage (Explain)		11,494,542
Gas Received from Shippers as Compressor Station Fuel		
Gas Received from Shippers as Lost and Unaccounted for		
Other Reciepts (Specify)		
Total Receipts		62,034,883
GAS DELIVERED		
Gas Sales (480-484)		30,704,772
Deliveries of gas Gathered for Others (Ref pg 303) (489.1)		
Deliveries of Gas Transported for Others (Ref Pg 305) (489.2)		1,934,902
Deliveries of Gas Distributed for Others (Ref Pg 301) (489.3)		12,175,233
Deliveries of Contract Storage gas (Ref Pg 307) (489.4)		
Exchange Gas Delivered to Others (Ref Pg 328) (806)		3,089,862
Gas Delivered as Imbalances (Ref Pg 328) (806)		
Deliveries of Gas to Others for Transportation (Ref Pg 332) (858)		
Other Gas Delivered to Storage (Explain)		12,135,856
Gas Used for Compressor Station Fuel (509)		151,988
Other Deliveries (Specify)		
	Duplicate Charges (Gas Department)	116,278
	Gas Used for Other Utility Operations	43,936
	Lost and Unaccounted from Gas Transports	18,270

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Gas Account - Natural Gas (Ref Page: 520)

Description	Amt MCF
28. Total Deliveries	60,371,097
GAS UNACCOUNTED FOR	
Production System Losses	
Gathering System Losses	
Transmission System Losses	
Distribution System Losses	
Storage System Losses	437,223
Other Losses (Specify)	
Sales and Transports	1,663,786
36. Total Unaccounted For	2,101,009
Total Deliveries and Unaccounted For For (Line 28 and 36)	62,472,106

Note:
Gas purchases include volumes recorded in Natural Gas Transmission Line Purchases (803).

Transportation gas is reported on the following lines:
Gas of Others Received for Distribution – 14,372,297 Mcf
Deliveries of Gas Transported for Others – 1,934,902 Mcf
Deliveries of Gas Distributed for Others – 12,175,233 Mcf

Other Gas Withdrawn from Storage represents net withdrawal of gas from storage recorded in Gas Withdrawn from Storage--Debit (808.1).

Other Gas Delivered to Storage represents net deliveries of gas to storage recorded in Gas Delivered to Storage--Credit (808.2).

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

CheckList

Item	Value 1	Value 2	Agree	Explain
Balance Sheet (Ref pg 110)				
Utility Plant agrees with Sched Summary of Utility Plant (Ref pg 200) Line 13. Total Utility Plant less Line 11. Construction Work In Progress	6131439950.00	6131439950.00	OK	
Line 3. Construction Work In Progress agrees with Sched Summary of Utility Plant (Ref pg 200) Line 11. Construction Work In Progress	389846496.00	389846496.00	OK	
Line 5. Accum. Prov for Depr and Amort Depl agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 14. Accum. Prov for Depr and Amort Depl	2015937460.00	2015937460.00	OK	
Line 5. Accum. Prov for Depr and Amort Depl agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 33. Total Accumulated Provisions	2015937460.00	2015937460.00	OK	
Line 6. Net Utility Plant agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 15. Net Utility Plant	4505348986.00	4505348986.00	OK	
Line 11. Utility Plant Adjustments are supported by Submitted Financial Statements as requested on Ref Pg 122				
Line 12. Gas Stored-Base Gas (117.1) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.1 (b)	2139990.00	2139990.00	OK	
Line 14. Gas Stored Underground - Non Current (117.3) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.4 (d)	0.0000	0.0000	OK	
Line 15. Gas Owned to System Gas (117.4) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.4 (e)	0.0000	0.0000	OK	
Line 17. Investments in Subsidiary Companies agrees with Sched Investments in Subsidiary Companies 123.1 (Ref Pg 224) Line Total Column Amt of Investment (g)	594286.00	594286.00	OK	
Line 47. Gas Stored Underground - Current (164.1) agrees with Sched Gas Stored Accounts (Ref Pg 220) Col 164.1 (f)	42068559.00	42068559.00	OK	

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 48. Liquefied Nat Gas Stored and Held (164.3) agrees with Sched Gas Stored Accounts (Ref Pg 220) Sum of Cols 164.2 and 164.3	0.0000	0.0000	OK	
Line 49. Prepayments agrees with Sched Prepayments (Ref Pg 230)	6472537.00	6472537.00	OK	
Line 58. Extraordinary Property Losses agrees with Sched Extraordinary Property Losses (Ref Pg 230)	0.0000	0.0000	OK	
Line 59 Unrecovered Plant and Regulatory Study Costs agrees with Sched Unrecovered Plant and Regulatory Study Costs (Ref Pg 230)	0.0000	0.0000	OK	
Line 65 Miscellaneous Deferred Debits agrees with Sched Miscellaneous Deferred Debits (Ref Pg 233)	458589969.00	458589969.00	OK	
Line 69 Accumulated Deferred Income Taxes agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Total Acct 190	286542027.00	286542027.00	OK	
Comparative Balance Sheet (Liabilities and Other Credits) (Ref Pg 112)				
Line 2. Common Stock Issued agrees with Sched Capital Stock (Ref Pg 250) Line Total Common Stock Col (f)	425170424.00	425170424.00	OK	
Line 3. Preferred Stock Issued agrees with Sched Capital Stock (Ref Pg 250) Line Total Preferred Stock Col (f)	0.0000	0.0000	OK	
Line 4. Capital Stock Subscribed agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Capital Stock Subscribed Col (d)	0.0000	0	OK	
Line 5. Stock Liability for Conversion agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Stock Liability for Conversion	0.0000	0	OK	
Line 6. Premium on Capital Stock agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Premium on Capital Stock	0.0000	0	OK	

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CheckList

Item	Value 1	Value 2	Agree	Explain
Line 7. Other Paid-in Capital Stock agrees with Sched Other Paid in Capital(Ref Pg 253) Line Total	1611167368.00	1611167368.00	OK	
Line 8 . Installmnts Recvd Capital Stk agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Tot Inst. Recvd on Capital Stock	0.0000	0	OK	
Line 9. Discount on Capital Stock agrees with Sched Discount on Capital Stock Acct 213 (Ref Pg 254) Line Total	0.0000	0.0000	OK	
Line 10. Capital Stock Expense agrees with Sched Capital Stock Expense Acct 214 (Ref Pg 254) Line Total	835889.00	835889.00	OK	
Line 11 Retained Earnings agrees with Statement of Retained Earnings for the Year (Ref Pg 118) Line 19. Total Retained Earnings	294897774.00	294897774.00	OK	
Line 12. Unappropriated Undistributed Subsidiary Earnings agrees with Statement of Retained Earnings for the Year (Ref Pg 118) Line 24. Balance End of Year	0.0000	0	OK	
Line 13. Reacquired Capital Stock agrees with Capital Stock (Ref Pg 250) Line Total col Acct 217 (h)	0.0000	0.0000	OK	
Line 39. Taxes Accrued agrees with Sched Taxes Accrued, Prepaid and Charged (Ref Pg 263) Line Total Col Acct 236 (g)	19925519.00	19925519.00	OK	
Line 45. Misc Current and Accrued Liabilities agrees with Sched Misc Current and Accured Liabilities (Ref Pg 268) Line Total	21396264.00	21396264.00	OK	
Line 52. Other Deferred Credits agrees with Sched Other Deferred Credits (Ref Pg 269) Line Total	4017629.00	4017629.00	OK	
Income Statement (Ref Pg 114)				
Line 2. Gas Operating Revenues agrees with Sched Gas Operating Revenues (Ref Pg 300) Line Total Col (h)	319521344.00	319521344.00	OK	

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

CheckList

Item	Value 1	Value 2	Agree	Explain
Sum of Lines 4 and 5 Operation and Maint Expenses agrees with Sched Gas Operation and Maintenance (Ref Pg 335) Line Total Gas O and M Expenses	214724979.00	214724979.00	OK	
Line 6. Depreciation Exp (403) agrees with Sched Depreciation, Depletion and Amort (Ref Pg 336) Line Total Col Depreciation (b)	29105118.00	29105118.00	OK	
Line 7. Amort and Depl (404-405) agrees with Sched Depreciation, Depletion and Amort (Ref Pg 336) Line Total Sum of Cols (c-f)	3199321.00	3199321.0000	OK	
Sum of Lines 13,14 and 15. Taxes (408.1-409.1) agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Line Total Col (j)	9487055.00	9487055.00	OK	
Line 16. Provision for Deferred Income Taxes (410.1) agrees with SUM OF Acct 190 (Ref Pg 234) Col c , Acct 282 (Ref Pg 274) Col c and Acct 282 (Ref Pg 276) Col c	447741617.00	447741617.00	OK	
Line 17. (Less) Provision for Deferred Income Taxes (411.1) agrees with SUM OF Acct 190 (Ref Pg 234) Col d , Acct 282 (Ref Pg 274) Col d and Acct 282 (Ref Pg 276) Col d	320258358.00	320258358.00	OK	
Income Statement (Ref Pg 116)				
Sum of Lines 48,49 and 50 agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Line Total Taxes Other Than Income Col (l)	-2162234.00	-2162234.00	OK	
Line 49. Provision for Deferred Inc. Taxes agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Line Total Acct 190 Col 410.2 (e)	230967.00	230967.00	OK	
Line 52. (Less) Provision for Deferred Inc. Taxes CR agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Line Total Acct 190 Col 411.2 (f)	42045.00	42045.00	OK	
Line 70. Income Taxes - Federal and Other agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Col 409.3 (m) Sum of Lines Total Income Taxes Federal and Other	0.0000	0.0000	OK	

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CheckList

Item	Value 1	Value 2	Agree	Explain
Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Pg 200)				
Line 8. Total Utility Plant agrees with Sched Gas Plant in Service (Ref Pg 206) Line Total Gas Plant in Service Col (g)	1021163077.00	1021163077.00	OK	
Line 10. Held for Future Use agrees with Sched Gas Plant Held for Future Use (Ref Pg 214) Line Total	0.0000	0	OK	
Line 11. Construction Work in Progress agrees with Sched Construction Work in Progress (Ref Pg 216) Line Total	22415538.00	22415538.00	OK	
Line 18. Depreciation agrees with Sched Accumulated Provision for Depreciation of Gas Utility Plant (Ref Pg 219) Line Balance at End of Year	288205594.00	288205594.00	OK	
Statement of Retained Earnings for the Year (Ref Pg 118)				
Line 10 Total Dividends Declared - Preferred Stock agrees with Statement of Cash Flows (Ref Pg 120) Line 68. Dividends on Preferred Stock	0	0	OK	
Line 11. Total Dividends Declared - Common Stock agrees with Statement of Cash Flows (Ref Pg 120) Line 69. Dividends on Common Stock	-119000000.00	-119000000.00	OK	
Miscellaneous General Expenses (Ref Pg 335)				
Line Total agrees with Sched Gas Operation and Maintenance (Ref Pg 323) Line Miscellaneous General Expenses	403836.00	403836.00	OK	

22200500 Louisville Gas and Electric Company 01/01/2015 - 12/31/2015

Upload supporting documents

Document	Description	Supports
SD_22200500_2015_1.pdf	Notes to Financial Statements	OTHER

OATH

Commonwealth of Kentucky)
) ss:
County of Jefferson)

Kent W. Blake makes oath and says
(Name of Officer)

that he/she is Chief Financial Officer of
(Official title of officer)

Louisville Gas and Electric Company
(Exact legal title or name of respondent)

that it is his/her duty to have supervision over the books of account of the respondent and to control the manner in which such books are kept; that he/she knows that such books have, during the period covered by the foregoing report, been kept in good faith in accordance with the accounting and other orders of the Public Service Commission of Kentucky, effective during the said period; that he/she has carefully examined the said report and to have the best of his/her knowledge and belief the entries contained in the said report have, so far as they relate to matters of account, been accurately taken from the said books of account and are in exact accordance therewith; that he/she believes that all other statements of fact contained in the said report are true; and that the said report is a correct and complete statement of the business and affairs of the above-named respondent during the period of time from and including

January 1, 20 15, to and including December 31, 20 15

KtWBlake
(Signature of Officer)

subscribed and sworn to before me, a Notary Public, in and for the State and County named in the above this 23rd day of March, 2016

(Apply Seal Here)

My Commission expires November 9, 2018

Tammy J. Elzy
(Signature of officer authorized to administer oath)

[Persons making willful false statements in this report may be punished by fine or imprisonment under KRS 523.040 and 523.100.]

Notes to Financial Statements

Per Kentucky PSC Order No. 2008-00007, attached are the "Notes to Financial Statements" for Louisville Gas & Electric Company as reported in the FERC Form No. 1 for the period ended December 31, 2015.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

GLOSSARY OF TERMS AND ABBREVIATIONS

KU **-** Kentucky Utilities Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky.

LG&E **-** Louisville Gas and Electric Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas in Kentucky.

LKE **-** LG&E and KU Energy LLC, a subsidiary of PPL and the parent of LG&E, KU and other subsidiaries.

LKS **-** LG&E and KU Services Company, a subsidiary of LKE that provides services to LKE and its subsidiaries.

PPL **-** PPL Corporation, the parent holding company of PPL Services, LKE and other subsidiaries.

PPL Services **-** PPL Services Corporation, a subsidiary of PPL that provides administrative, management and support services to PPL and its subsidiaries.

Other terms and abbreviations

401(h) account(s) **-** A sub account established within a qualified pension trust to provide for the payment of retiree medical costs.

AFUDC **-** Allowance for Funds Used During Construction. The cost of equity and debt funds used to finance construction projects of regulated businesses, which is capitalized as part of construction costs.

ARO **-** asset retirement obligation.

BSER **-** Best System of Emission Reduction. The degree of emission reduction that EPA determines has been adequately demonstrated when taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements.

Cane Run Unit 7 **-** a natural gas combined-cycle generating unit in Kentucky, jointly owned by LG&E and KU, with a capacity of 642 MW (141 MW and 501 MW to LG&E and KU).

CCR(s) **-** Coal Combustion Residual(s). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes.

Clean Air Act **-** federal legislation enacted to address certain environmental issues related to air emissions, including acid rain, ozone and toxic air emissions.

Clean Water Act **-** federal legislation enacted to address certain environmental issues relating to water quality including effluent discharges, cooling water intake, and dredge and fill activities.

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

CPCN **-** Certificate of Public Convenience and Necessity. Authority granted by the KPSC pursuant to Kentucky Revised Statute 278.020 to provide utility service to or for the public or the construction of certain plant, equipment, property or facility for furnishing of utility service to the public.

DSM **-** Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM plans proposed by any utility under its jurisdiction. Proposed DSM mechanisms may seek full recovery of costs and revenues lost by implementing DSM programs and/or incentives designed to provide financial rewards to the utility for implementing cost-effective DSM programs. The cost of such programs shall be assigned only to the class or classes of customers which benefit from the programs.

EBPB **-** Employee Benefit Plan Board. The administrator of PPL's U.S. qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

ECR **-** Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, Kentucky electric utilities are entitled to the current recovery of costs of complying with the Clean Air Act, as amended, and those federal, state or local environmental requirements that apply to coal combustion wastes and by-products from the production of energy from coal.

ELG(s) **-** Effluent Limitation Guidelines, regulations promulgated by the EPA.

EPA **-** Environmental Protection Agency, a U.S. government agency.

FERC **-** Federal Energy Regulatory Commission, the U.S. federal agency that regulates, among other things, interstate transmission and wholesale sales of electricity, hydroelectric power projects and related matters.

GAAP **-** Generally Accepted Accounting Principles in the U.S.

GHG **-** greenhouse gas(es).

GLT **-** Gas Line Tracker. The KPSC approved mechanism for LG&E's recovery of costs associated with gas service lines, gas risers, leak mitigation, and gas main replacements. Rate recovery became effective January 1, 2013.

KPSC **-** Kentucky Public Service Commission, the state agency that has jurisdiction over the regulation of rates and service of utilities in Kentucky.

kWh **-** kilowatt hour, basic unit of electrical energy.

LG&E 2010 Mortgage Indenture **-** LG&E's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as supplemented.

LIBOR **-** London Interbank Offered Rate.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

MATS **-** Mercury and Air Toxics Standards, regulations promulgated by the EPA.

MW **-** megawatt, one thousand kilowatts.

NAAQS **-** National Ambient Air Quality Standards periodically adopted pursuant to the Clean Air Act.

NERC **-** North American Electric Reliability Corporation.

NGCC **-** Natural gas-fired combined-cycle generating plant.

NPNS **-** the normal purchases and normal sales exception as permitted by derivative accounting rules. Derivatives that qualify for this exception may receive accrual accounting treatment.

NSR **-** The new source review provisions of the Clean Air Act that impose stringent emission control requirements on new and modified sources of air emissions that result in emission increases beyond thresholds allowed by the Clean Air Act.

OCI **-** other comprehensive income or loss.

OVEC **-** Ohio Valley Electric Corporation, located in Piketon, Ohio, an entity in which LKE indirectly owns an 8.13% interest (consists of LG&E's 5.63% and KU's 2.50% interests), which is accounted for as a cost-method investment. OVEC owns and operates two coal-fired power plants, the Kyger Creek plant in Ohio and the Clifty Creek plant in Indiana, with combined summer rating capacities of 2,120 MW.

PP&E **-** property, plant and equipment.

RCRA **-** Resource Conservation and Recovery Act of 1976.

RFC **-** Reliability*First* Corporation, one of eight regional entities with delegated authority from NERC that work to safeguard the reliability of the bulk power systems throughout North America.

SCRs **-** selective catalytic reduction, a pollution control process for the removal of nitrogen oxide from exhaust gas.

Scrubber **-** an air pollution control device that can remove particulates and/or gases (primarily sulfur dioxide) from exhaust gases.

SEC **-** the U.S. Securities and Exchange Commission, a U.S. government agency primarily responsible to protect investors and maintain the integrity of the securities markets.

SERC **-** SERC Reliability Corporation, one of eight regional entities with delegated authority from NERC that work to safeguard the reliability of the bulk power systems throughout North America.

Superfund **-** federal environmental statute that addresses remediation of contaminated sites; states also have similar statues.

VEBA **-** Voluntary Employee Benefit Association Trust, accounts for health and welfare plans for future benefit payments for employees, retirees or their beneficiaries.

Volumetric risk **-** the risk that the actual load volumes provided under full-requirement sales contracts could vary significantly from forecasted volumes.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

As permitted by the FERC for the Year Ended December 31, 2015 Form 1, the Notes to Financial Statements set forth below are principally from the Respondent's SEC Form 10-K for the Year Ended December 31, 2015, which was filed with the SEC on February 19, 2016. Accordingly, these Notes do not reflect updated information since this filing date.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

Capitalized terms and abbreviations appearing in the notes to financial statements are defined in the glossary. Dollars are in millions unless otherwise noted.

Presentation

The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than GAAP. The significant differences between GAAP and FERC reporting are as follows:

(a) Certain cost of removal obligations are recorded in accumulated depreciation for FERC reporting and recorded in regulatory liabilities for GAAP reporting;
(b) Long-term and short-term bonds are recorded in total in the long-term debt section for FERC reporting and are presented separately in current liabilities for the short-term portion and in long-term debt for the long-term portion for GAAP reporting;
(c) Deferred taxes are shown gross for FERC reporting in the Balance Sheet (a deferred asset and a deferred liability are recorded), but for GAAP reporting the deferred taxes are netted together and recorded as a net asset or net liability;
(d) Utility plant acquired before November 1, 2010 is stated at cost for FERC reporting and was restated to net fair value as of November 1, 2010, for GAAP reporting;
(e) Long-term and short-term regulatory assets are presented together in deferred debits for FERC reporting. For GAAP reporting, short-term regulatory assets are presented in current assets and long-term regulatory assets are presented in other noncurrent assets; and
(f) Long-term and short-term regulatory liabilities are presented together in deferred credits for FERC reporting. For GAAP reporting, short-term regulatory liabilities are presented in current liabilities and long-term regulatory liabilities are presented in deferred credits and other noncurrent liabilities.
(g) Deferred financing costs are classified as assets for FERC reporting. For GAAP reporting, such costs are classified as contra-liabilities and are presented together with long-term debts.

Business and Consolidation

LG&E is engaged in the generation, transmission, distribution and sale of electricity. LG&E also engages in the distribution and sale of natural gas.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

LG&E has no controlling interest in any Variable Interest Entities (VIEs). All other investments are carried at cost or fair value.

LG&E's financial statements include its share of any undivided interests in jointly owned facilities, as well as its share of the related operating costs of those facilities. See Note 9 for additional information.

Regulation

LG&E is a cost-based rate-regulated utility for which rates are set by regulators to enable LG&E to recover the costs of providing electric or gas service and to provide a reasonable return to its shareholder. Base rates are generally established based on a future test period. Regulatory assets are recognized for the effect of transactions or events where future recovery of underlying costs is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise currently be charged to expense. Regulatory liabilities are recognized for amounts expected to be returned through future regulated customer rates. In certain cases, regulatory liabilities are recorded based on an understanding or agreement with the regulator that rates have been set to recover costs that are expected to be incurred in the future, and the regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and regulatory liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC or the applicable state regulatory commissions. See Note 4 for additional details regarding regulatory matters.

Accounting Records

LG&E's system of accounts is maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the applicable state regulatory commissions.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." LG&E continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events. Loss accruals for environmental remediation are discounted when appropriate.

The accrual of contingencies that might result in gains is not recorded, unless realization is assured.

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Changes in Classification

The classification of certain amounts in the 2014 financial statements have been changed to conform to the current presentation. These reclassifications did not affect LG&E’s net income or equity.

Price Risk Management

Interest rate contracts are used to hedge exposure to change in the fair value of debt instruments and to hedge exposures to variability in expected cash flows associated with existing floating-rate debt instruments or forecasted fixed-rate issuances of debt. Similar derivatives may receive different accounting treatment, depending on management's intended use and documentation.

Certain contracts may not meet the definition of a derivative because they lack a notional amount or a net settlement provision. In cases where there is no net settlement provision, markets are periodically assessed to determine whether market mechanisms have evolved that would facilitate net settlement. Certain derivative contracts may be excluded from the requirements of derivative accounting treatment because NPNS has been elected. These contracts are accounted for using accrual accounting. Contracts that have been classified as derivative contracts are reflected on the Balance Sheets at fair value. The portion of derivative positions that deliver within a year are included in "Current Assets" and "Current Liabilities," while the portion of derivative positions that deliver beyond a year are recorded in "Other Noncurrent Assets" and "Deferred Credits and Other Noncurrent Liabilities." LG&E considers intra-month transactions to be spot activity, which is not accounted for as a derivative.

Processes exist that allow for subsequent review and validation of the contract information as it relates to interest rate derivatives. The accounting department provides the treasury department with guidelines on appropriate accounting classifications for various contract types and strategies. Examples of accounting guidelines provided to the treasury department staff include, but are not limited to:

- Transactions to lock in an interest rate prior to a debt issuance can be designated as cash flow hedges, to the extent the forecasted debt issuances remain probable of occurring.

- Derivative transactions may be marked to fair value through regulatory assets/liabilities if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps that are included in customer rates.

Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing activities on the Statements of Cash Flows, depending on the classification of the hedged items.

LG&E has elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

See Notes 12 and 13 for additional information on derivatives.

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Revenue

Revenue Recognition

Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all meters being read and bills rendered at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh. Any difference between estimated and actual revenues is adjusted the following month.

Accounts Receivable

Accounts receivable are reported on the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

Accounts receivable collectability is evaluated using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness and economic conditions. Specific events, such as bankruptcies, are also considered. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables and historical and industry trends.

Accounts receivable are written off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when it is known they will be received.

The changes in the allowance for doubtful accounts at December 31 were:

		Additions			
	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
2015	$ 2	$ 2	$ -	$ 3	$ 1
2014	2	5	(1)	4	2

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work in progress.
(b) Primarily related to uncollectible accounts written off.

Cash

Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered to be cash equivalents.

Fair Value Measurements

LG&E values certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities, investments in securities in defined benefit plans, and cash and cash equivalents. LG&E uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

LG&E classifies fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

• **Level 1 -** quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

• **Level 2 -** inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.

• **Level 3 -** unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, LG&E's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent

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assets or for the liquidation of long-term debts, are classified as long-term.

Short-term Investments

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in "Short-term investments" ("Other current assets" if not significant) on the Balance Sheets.

Cost Method Investment

LG&E has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the Balance Sheets. LG&E and 11 other electric utilities are equity owners of OVEC. OVEC's power is currently supplied to LG&E and 12 other companies affiliated with the various owners. LG&E owns 5.63% of OVEC's common stock. Pursuant to a power purchase agreement, LG&E is contractually entitled to its ownership percentage of OVEC's output, which is approximately 120 MW.

LG&E's investment in OVEC is not significant. The direct exposure to loss as a result of LG&E's involvement with OVEC is generally limited to the value of its investment; however, LG&E is conditionally responsible for a pro-rata share of certain OVEC obligations. As part of PPL's acquisition of LKE, the value of the power purchase contract was recorded as an intangible asset with an offsetting regulatory liability, both of which are being amortized using the units-of-production method until March 2026, the expiration date of the agreement. See Notes 10 and 14 for additional discussion of the power purchase agreement.

Long-Lived and Intangible Assets

Property, Plant and Equipment

PP&E is recorded at original cost, unless impaired. PP&E acquired in business combinations is recorded at fair value at the time of acquisition, which establishes its original cost. If impaired, the asset is written down to fair value at that time, which becomes the new cost basis of the asset. Original cost for constructed assets includes material, labor, contractor costs, certain overheads and financing costs, where applicable. The cost of repairs and minor replacements are charged to expense as incurred. LG&E records costs associated with planned major maintenance projects in the period in which the costs are incurred. No costs associated with planned major maintenance projects are accrued in advance of the period in which the work is performed. LG&E accrues costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. Cost of removal amounts accrued through depreciation rates are accumulated as a regulatory liability until the removal costs are incurred. See "Asset Retirement Obligations" below and Note 4 for additional information.

LG&E does not record AFUDC as a return is provided on construction work in progress.

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Depreciation

Depreciation is recorded over the estimated useful lives of property using various methods including the straight-line, composite and group methods. When a component of PP&E that was depreciated under the composite or group method is retired, the original cost is charged to accumulated depreciation. When all or a significant portion of an operating unit that was depreciated under the composite or group method is retired or sold, the property and the related accumulated depreciation account is reduced and any gain or loss is included in income, unless otherwise required by regulators. LG&E's weighted-average rates of depreciation for regulated utility plant were 3.65% and 4.05% at December 31, 2015 and 2014.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the purchase price paid over the fair value of the identifiable net assets acquired in a business combination.

Other acquired intangible assets are initially measured based on their fair value. Intangibles that have finite useful lives are amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. Costs incurred to obtain an initial license and renew or extend terms of licenses are capitalized as intangible assets.

When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, LG&E considers the expected use of the asset; the expected useful life of other assets to which the useful life of the intangible asset may relate; legal, regulatory, or contractual provisions that may limit the useful life; the company's historical experience as evidence of its ability to support renewal or extension; the effects of obsolescence, demand, competition, and other economic factors; and the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

LG&E accounts for emission allowances as intangible assets. LG&E is allocated emission allowances by states based on its generation facilities' historical emissions experience, and have purchased emission allowances generally when it is expected that additional allowances will be needed. The carrying value of allocated emission allowances is initially recorded at zero value and purchased allowances are initially recorded based on their purchase price. When consumed or sold, emission allowances are removed from the Balance Sheet at their weighted-average carrying value. Since the economic benefits of emission allowances are not diminished until they are consumed, emission allowances are not amortized; rather, they are expensed when consumed or a gain or loss is recognized when sold. Such expense is included in "Fuel" on the Statements of Income. Gains and losses on the sale of emission allowances are included in "Other operation and maintenance" on the Statements of Income.

Asset Impairment (Excluding Investments)

LG&E reviews long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles, for impairment when events or circumstances indicate carrying amounts may not be recoverable.

A long-lived asset classified as held and used is impaired when the carrying amount of the asset exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If impaired, the asset's carrying value is written down to its fair value.

A long-lived asset classified as held for sale is impaired when the carrying amount of the asset (disposal group) exceeds its fair value less cost to sell. If impaired, the asset's (disposal group's) carrying value is written down to its fair value less cost to sell.

LG&E reviews goodwill for impairment at the reporting unit level annually or more frequently when events or circumstances indicate that the carrying amount of a reporting unit may be greater than the unit's fair value. Additionally, goodwill must be tested for impairment in circumstances when a portion of goodwill has been allocated to a business to be disposed. LG&E is a single reporting unit.

LG&E may elect either to initially make a qualitative evaluation about the likelihood of an impairment of goodwill or to bypass the qualitative evaluation and test goodwill for impairment using a two-step quantitative test. If the qualitative evaluation (referred to as "step zero") is elected and the assessment results in a determination that it is not more likely than not that the fair value of a reporting unit is less than the carrying amount, the two-step quantitative impairment test is not necessary. However, the quantitative impairment test is required if management concludes it is more likely than not that the fair value of a reporting unit is less than the carrying amount based on the step zero assessment.

If the carrying amount of the reporting unit, including goodwill, exceeds its fair value, the implied fair value of goodwill must be calculated in the same manner as goodwill in a business combination. The fair value of a reporting unit is allocated to all assets and liabilities of that unit as if the reporting unit had been acquired in a business combination. The excess of the fair value of the reporting unit over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, goodwill is written down to its implied fair value.

LG&E elected to bypass step zero and quantitatively tested its goodwill for impairment in the fourth quarter of 2015 and no impairment was recognized.

Asset Retirement Obligations

LG&E records liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased through the recognition of accretion expense to reflect changes in the obligation due to the passage of time. The accretion and depreciation expenses recorded by LG&E are recorded as a regulatory asset, such that there is no earnings impact.

Estimated ARO costs and settlement dates, which affect the carrying value of the ARO and the related capitalized asset, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the ARO. Any change to the capitalized asset, positive or negative, is generally amortized over the remaining life of the associated long-lived asset. See Note 15 for additional information on AROs.

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Compensation and Benefits

Defined Benefits

LG&E sponsors and participates in various defined benefit pension and other postretirement plans. The plans LG&E participates in are sponsored by LG&E and LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to LG&E based on its participation in those plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value.

LG&E and LKE use an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan's projected benefit obligation are amortized on a straight-line basis over one-half of the expected average remaining service of active plan participants. Actuarial gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or the market-related value of plan assets and less than 30% of the plan's projected benefit obligation are amortized on a straight-line basis over the expected average remaining service period of active plan participants.

See Note 4 for a discussion of the regulatory treatment of defined benefit costs and Note 8 for a discussion of defined benefits.

Taxes

Income Taxes

LG&E is included in PPL’s consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E’s provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and valuation allowances on deferred tax assets.

Significant management judgment is also required to determine the amount of benefit to be recognized in relation to an uncertain tax position. LG&E uses a two-step process to evaluate tax positions. The first step requires LG&E to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires LG&E to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact LG&E's financial statements in future periods.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If LG&E determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if LG&E determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

LG&E defers investment tax credits when the credits are utilized and amortize the deferred amounts over the average lives of the related assets.

LG&E recognizes interest and penalties in "Income Taxes" on its Statements of Income.

LG&E's provision for deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in noncurrent "Regulatory assets" or "Regulatory liabilities."

LG&E's income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E filed a separate return. Tax benefits are not shared between companies. LG&E is only entitled to tax benefits that it generated. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes. LG&E's intercompany tax receivables were $4 million and $74 million at December 31, 2015 and 2014.

Taxes, Other Than Income

LG&E presents sales taxes in "Other current liabilities" on the Balance Sheets. These taxes are not reflected on the Statements of Income. See Note 3 for details on taxes included in "Taxes, other than income" on the Statements of Income.

Other

Leases

LG&E evaluates whether arrangements entered into contain leases for accounting purposes. See Note 7 for additional information.

Fuel, Materials and Supplies

Fuel, natural gas stored underground and materials and supplies are valued at the lower of cost or net realizable value using the average cost method. Fuel costs for electric generation are charged to expense as used. Natural gas supply costs are charged to expense as delivered to the distribution system. See Note 4 for further discussion of the fuel adjustment clause and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2015	2014
Fuel	$ 71	$ 66
Natural gas stored underground (a)	42	54
Materials and supplies	38	42
Total	$ 151	$ 162

(a) The majority of natural gas stored underground is held to serve retail customers.

Guarantees

Generally, the initial measurement of a guarantee liability is the fair value of the guarantee at its inception. However, there are certain guarantees excluded from the scope of accounting guidance and other guarantees that are not subject to the initial recognition and measurement provisions of accounting guidance that only require disclosure. See Note 10 for further discussion of recorded and unrecorded guarantees.

New Accounting Guidance Adopted

Fair Value Measurement for Investments in Certain Entities that Calculate Net Asset Value per Share

Effective December 31, 2015, LG&E retrospectively adopted accounting guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using net asset value per share and the requirement to make certain disclosures for all investments that are eligible to be measured using net asset value per share.

The adoption of this guidance resulted in LG&E no longer categorizing investments for which fair value is measured using net asset value per share in the fair value hierarchy, and did not have a significant impact on LG&E. See Note 8 for additional information.

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Presentation of Debt Issuance Costs

Effective December 31, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of debt issuance costs. The guidance requires certain debt issuance costs to be presented on the Balance Sheet as a direct deduction from the carrying amount of the associated debt liability.

The adoption of this guidance required LG&E to reclassify debt issuance costs not associated with a line of credit from noncurrent assets to Long-term debt, and did not have a significant impact. See Note 5 for additional information.

Balance Sheet Classification of Deferred Taxes

Effective October 1, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of deferred taxes which requires that deferred tax assets and deferred tax liabilities be classified as noncurrent on the Balance Sheet.

The adoption of this guidance required LG&E to reclassify deferred tax assets and deferred tax liabilities from current to noncurrent on the Balance Sheet, and did not have a significant impact. LG&E did not have any current deferred tax assets and liabilities on the Balance Sheet as of December 31, 2014.

2. Preferred Securities

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2015 or 2014.

3. Income and Other Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes and the tax effects of net operating loss and tax credit carryforwards. Net deferred tax assets have been recognized based on management's estimates of future taxable income.

LG&E’s provision for deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC and the FERC. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets.

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Significant components of LG&E's deferred income tax assets and liabilities at December 31 were as follows:

	2015	2014
Deferred Tax Assets		
Federal loss carryforwards (a)	$ 76	$ -
Regulatory liabilities	38	51
Deferred investment tax credits	13	14
Income taxes due to customers	17	18
Derivative liability	18	32
Other	15	9
Total deferred tax assets	177	124
Deferred Tax Liabilities		
Plant - net	896	698
Regulatory assets	75	90
Accrued pension costs	28	28
Other	7	8
Total deferred tax liabilities	1,006	824
Net deferred tax liability	$ 829	$ 700

(a) Increase in Federal loss carryforwards primarily relates to the extension of bonus depreciation.

LG&E expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

At December 31, 2015, LG&E had $218 million of federal net operating loss carryforwards that expire in 2035, $1 million of federal credit carryforwards that expire from 2031 to 2035 and $2 million of state credit carryforwards that expire in 2022.

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Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were:

	2015	2014
Income Tax Expense (Benefit)		
Current - Federal	$ (15)	$ (25)
Current - State	3	10
Total Current Expense (Benefit)	(12)	(15)
Deferred - Federal	190	114
Deferred - State	13	6
Total Deferred Expense, excluding benefits of operating loss carryforwards	203	120
Investment tax credit, net - Federal	(1)	(2)
Tax benefit of operating loss carryforwards		
Deferred - Federal	(76)	-
Total Tax Benefit of Operating Loss Carryforwards	(76)	-
Total income tax expense	$ 114	$ 103
Total income tax expense - Federal	$ 98	$ 87
Total income tax expense - State	16	16
Total income tax expense	$ 114	$ 103

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	2015	2014
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 105	$ 95
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	11	10
Amortization of investment tax credit	(1)	(2)
Other	(1)	-
Total increase	9	8
Total income tax expense	$ 114	$ 103
Effective income tax rate	38.1%	37.9%

	2015	2014
Taxes, other than income		
Property and other	$ 28	$ 25
Total	$ 28	$ 25

Unrecognized Tax Benefits

LG&E’s income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E filed a separate return. Based on this tax sharing agreement, LG&E indirectly files tax returns in two major tax jurisdictions. With few exceptions, at December 31, 2015, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows:

U.S. (federal)	2011 and prior
Kentucky (state)	2010 and prior

4. Utility Rate Regulation

Regulatory Assets and Liabilities

LG&E reflects the effects of regulatory actions in the financial statements for its cost-based rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the Balance Sheet date.

LG&E is subject to the jurisdiction of the KPSC and FERC.

LG&E's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and short-term debt) including adjustments for certain net investments and costs recovered separately through

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other means. As such, LG&E generally earns a return on regulatory assets.

As a result of purchase accounting requirements, certain fair value amounts related to contracts that had favorable or unfavorable terms relative to market were recorded on the Balance Sheet with an offsetting regulatory asset or liability. LG&E recovers in customer rates the cost of coal contracts, power purchases and emission allowances. As a result, management believes the regulatory assets and liabilities created to offset the fair value amounts at LKE's acquisition date meet the recognition criteria established by existing accounting guidance and eliminate any rate-making impact of the fair value adjustments. LG&E's customer rates will continue to reflect the original contracted prices for these contracts.

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The following table provides information about the regulatory assets and liabilities of cost-based rate-regulated utility operations at December 31.

	2015	2014
Current Regulatory Assets:		
Environmental cost recovery	$ 13	$ 4
Gas supply clause	1	15
Fuel adjustment clause	-	2
Gas line tracker	1	-
Other	1	-
Total current regulatory assets	$ 16	$ 21
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 215	$ 215
Storm costs	35	43
Unamortized loss on debt	17	18
Interest rate swaps	98	89
AROs	57	28
Other	2	4
Total noncurrent regulatory assets	$ 424	$ 397
Current Regulatory Liabilities:		
Demand side management	$ 4	$ 1
Gas supply clause	6	6
Fuel adjustment clause	2	-
Gas line tracker	-	3
Other	1	-
Total current regulatory liabilities	$ 13	$ 10
Noncurrent Regulatory Liabilities:		
Coal contracts (a)	$ 7	$ 25
Power purchase agreement - OVEC (a)	57	63
Net deferred tax assets	23	24
Interest rate swaps	41	42
Other	2	2
Total noncurrent regulatory liabilities	$ 130	$ 156

(a) These liabilities were recorded as offsets to certain intangible assets that were recorded at fair value upon the acquisition of LKE by PPL.

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Following is an overview of selected regulatory assets and liabilities detailed in the preceding tables. Specific developments with respect to certain of these regulatory assets and liabilities are discussed in "Regulatory Matters."

Defined Benefit Plans

Defined benefit plan regulatory assets represent the portion of unrecognized transition obligation, prior service cost and net actuarial gains and losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices and generally, are amortized over the average remaining service lives of plan participants. These regulatory assets are adjusted at least annually or whenever the funded status of defined benefit plans is re-measured. Of the regulatory asset balances recorded, costs of $19 million are expected to be amortized into net periodic defined benefit costs in 2016 in accordance with LG&E's pension accounting policy.

As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between pension cost calculated in accordance with LG&E's pension accounting policy and pension cost calculated using a 15 year amortization period for actuarial gains and losses is recorded as a regulatory asset. As of December 31, 2015, the balance was $6 million. Of the costs expected to be amortized into net periodic defined benefit costs in 2016, $6 million is expected to be recorded as a regulatory asset in 2016.

Storm Costs

LG&E has the ability to request from the KPSC, the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer such costs for regulatory accounting and reporting purposes. Once such authority is granted, LG&E can request recovery of those expenses in a base rate case and begin amortizing the costs when recovery starts. LG&E's regulatory assets for storm costs are being amortized through various dates ending in 2020.

Unamortized Loss on Debt

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed that have been deferred and will be amortized and recovered over either the original life of the extinguished debt or the life of the replacement debt (in the case of refinancing). Such costs are being amortized through 2035.

Environmental Cost Recovery

Kentucky law permits LG&E to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Clean Air Act and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from coal-fired electric generating facilities. The KPSC requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, LG&E was authorized to earn a 10% return on equity for all its existing ECR plans. The ECR regulatory asset or liability represents the amount that has been under- or over-recovered due to timing or adjustments to the mechanism and is typically recovered within 12 months.

Gas Supply Clause

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause includes a separate natural gas procurement incentive mechanism, which allows LG&E's rates to be adjusted annually to share variances between actual costs and market indices between the shareholders and the customers during each performance-based rate year (12 months ending October 31). The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are typically recovered within 18 months.

Fuel Adjustment Clauses

LG&E's retail electric rates contain a fuel adjustment clause, whereby variances in the cost of fuel to generate electricity, including transportation costs, from the costs embedded in base rates are adjusted in LG&E's rates. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel adjustment clause and, to the extent appropriate, reestablish the fuel charge included in base rates. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are typically recovered within 12 months.

Demand Side Management

LG&E's DSM program consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. LG&E's rates contain a DSM provision which includes a rate recovery mechanism that provides for concurrent recovery of DSM costs and incentives, and allows for the recovery of DSM revenues from lost sales associated with the DSM programs. Additionally, LG&E earns an approved return on equity for capital expenditures associated with the residential and commercial load management/demand conservation programs. The cost of DSM programs is assigned only to the class or classes of customers that benefit from the programs.

Interest Rate Swaps

Periodically, LG&E has entered into forward-starting interest rate swaps to hedge forecasted debt issuance with PPL that have terms identical to forward-starting swaps entered into by PPL with third parties. Net realized gains and losses on all of these swaps are probable of recovery through regulated rates; as such, any gains and losses on these derivatives are included in regulatory assets or liabilities and will be recognized in "Interest Expense" on the Statements of Income over the life of the underlying debt at the time the underlying hedged interest expense is recorded. In September 2015, first mortgage bonds totaling $550 million were issued and all outstanding forward-starting interest rate swaps were terminated. Net cash settlements of $44 million were paid on the swaps that were terminated. Net realized losses on these terminated swaps will be recovered through regulated rates. As such, the net settlements were recorded in regulatory assets and are being recognized in

"Interest Expense" on the Statements of Income over the life of the new debt that matures in 2025 and 2045. There were no forward starting interest rate swaps outstanding at December 31, 2015. See Note 13 for additional information related to the forward-starting interest rate swaps.

Net cash settlements of $43 million were received on forward starting interest rate swaps that were terminated in 2013. Net realized gains on these terminated swaps will be returned through regulated rates. As such, the net settlements were recorded as regulatory liabilities and are being recognized in "Interest Expense" on the Statements of Income over the life of the associated debt that matures in 2043.

In addition to the terminated forward starting interest rate swaps, realized amounts associated with LG&E's other interest rate swaps, including a terminated swap contract from 2008, are recoverable through rates based on an order from the KPSC, LG&E's unrealized losses and gains are recorded as a regulatory asset or liability until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures through 2033. Amortization of the gain or loss related to the 2008 terminated swap contract is to be recovered through 2035.

<u>AROs</u>

The accretion and depreciation expenses related to LG&E's AROs are recorded as a regulatory asset, such that there is no earnings impact. When an asset with an ARO is retired, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

<u>Gas Line Tracker</u>

The GLT authorizes LG&E to recover its incremental operating expenses, depreciation, property taxes, and its cost of capital including a return on equity for capital associated with the five year gas service riser, leak mitigation and customer service line ownership programs. As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, LG&E is authorized to earn a 10% return on equity for the GLT mechanism. As part of this program, LG&E makes necessary repairs and assumes ownership of natural gas lines. LG&E annually files projected costs in October to become effective on the first billing cycle in January. After the completion of a plan year, LG&E submits a balancing adjustment filing to the KPSC to amend rates charged for the differences between the actual costs and actual GLT charges for the preceding year. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to these timing differences.

<u>Coal Contracts</u>

As a result of purchase accounting associated with PPL's acquisition of LKE, LG&E's coal contracts were recorded at fair value on the Balance Sheet with offsets to regulatory assets for those contracts with unfavorable terms relative to current market prices and offsets to regulatory liabilities for those contracts with favorable terms relative to current market prices. These regulatory assets and liabilities are being amortized over the same terms as the related contracts, which expire at various times through 2016.

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Power Purchase Agreement - OVEC

As a result of purchase accounting associated with PPL's acquisition of LKE, the fair value of the OVEC power purchase agreement was recorded on the Balance Sheet with offsets to regulatory liabilities. The regulatory liabilities are being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition.

Regulatory Liability Associated with Net Deferred Tax Assets

LG&E's regulatory liabilities associated with net deferred tax assets represent the future revenue impact from the reversal of deferred income taxes required primarily for unamortized investment tax credits. These regulatory liabilities are recognized when the offsetting deferred tax assets are recognized.

Regulatory Matters

Rate Case Proceedings

On June 30, 2015, the KPSC approved a rate case settlement agreement providing for increases in the annual revenue requirements associated with base gas rates of $7 million. The annual revenue requirement associated with base electricity rates was not changed. Although the settlement did not establish a specific return on equity with respect to the base rates, an authorized 10% return on equity will be utilized in the ECR and GLT mechanisms. The settlement also provides regulatory asset treatment for the difference between pension expense calculated in accordance with LG&E’s pension accounting policy and pension expense using a 15 year amortization period for actuarial gains and losses. The new rates and all elements of the settlement became effective July 1, 2015.

KPSC Landfill Proceedings

On May 22, 2015, LG&E and KU filed an application with the KPSC for a declaratory order that the existing CPCN and ECR approvals regarding the initial phases of construction and rate recovery of the landfill for management of CCRs at the Trimble County Station remain in effect. The current design of the proposed landfill provides for construction in substantially the same location as originally proposed with approximately the same storage capacity and expected useful life. On May 20, 2015, the owner of an underground limestone mine filed a complaint with the KPSC requesting it to revoke the CPCN for the Trimble County landfill and limit recovery of costs for the Ghent Station landfill on the grounds that, as a result of cost increases, the proposed landfill no longer constitutes the least cost alternative for CCR management. The KPSC has initiated its own investigation, consolidated the proceedings, and ordered an accelerated procedural schedule. The KPSC conducted a hearing on the matter in September 2015. On December 15, 2015, the KPSC issued an order affirming LG&E and KU's existing CPCN and ECR authority for Phase 1 of the Trimble County and Ghent landfills and related facilities, and that the landfills are the least cost options for disposing of the combustion wastes. Additionally, the order requires LG&E and KU to file a CPCN prior to constructing Phases 2 and 3 at the Ghent landfill and Phases 2 through 4 at the Trimble County landfill. The order also requires LG&E and KU to submit status update reports every three months on Phase 1 of Trimble County landfill. Phase 1 of construction at Trimble County will commence after the required state permits are obtained. Phase 1 of the

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Ghent landfill was completed in December 2014.

CPCN and ECR Filing

On January 29, 2016, LG&E submitted an application to the KPSC for CPCNs and for ECR rate treatment regarding upcoming environmental construction projects relating to the EPA's regulations addressing the handling of coal combustion byproducts and MATS. The construction projects are expected to begin in 2016 and continue through 2023 and are estimated to cost LG&E approximately $316 million. The application requests an authorized 10% return on equity with respect to LG&E's ECR mechanism consistent with the 2014 Kentucky rate case approved in June 2015.

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5. Financing Activities

Credit Arrangements and Short-term Debt

LG&E maintains a credit facility to enhance liquidity, provide credit support and provide a backstop to commercial paper programs. The amounts borrowed below are recorded as "Short-term debt" on the Balance Sheets. The following credit facility was in place at:

	December 31, 2015				
	Expiration Date	Capacity	Borrowed	Letters of Credit and Commercial Paper Issued	Unused Capacity
Syndicated Credit Facility (a) (b)	July 2019	$ 500	-	$ 142	$ 358

	December 31, 2014	
	Borrowed	Letters of Credit and Commercial Paper Issued
Syndicated Credit Facility (a) (b)	-	$ 264

(a) LG&E pays customary fees under its facility and borrowings generally bear interest at LIBOR-based rates plus an applicable margin.
(b) The facilities contain a financial covenant requiring debt to total capitalization not to exceed 70% as calculated in accordance with the facility and other customary covenants. Additionally, as it relates to the syndicated credit facility and subject to certain conditions, LG&E may request up to a $100 million increase in its facility's capacity.

In January 2016, the expiration date for LG&E’s syndicated credit facility expiring in July 2019 was extended to December 2020.

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LG&E maintains a commercial paper program to provide an additional financing source to fund short-term liquidity needs, as necessary. Commercial paper issuances, included in "Short-term debt" on the Balance Sheets, are supported by LG&E's syndicated credit facility. The following commercial paper program was in place at:

December 31, 2015

Weighted - Average Interest Rate	Capacity	Commercial Paper Issuances	Unused Capacity
0.71%	$ 350	$ 142	$ 208

December 31, 2014

Weighted - Average Interest Rate	Commercial Paper Issuances
0.42%	$ 264

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Long-term Debt

	Weighted - Average Rate	Maturities (c)	December 31, 2015
First Mortgage Bonds (a) (b)	3.36%	2016 - 2045	$ 1,659
Total Long-term Debt Before Adjustments			1,659
Other			
Fair market value adjustments			(1)
Unamortized discount			(4)
Unamortized debt issuance costs			(12)
Total Long-term Debt			1,642
Less current portion of Long-term Debt			25
Total Long-term Debt, noncurrent			$ 1,617

			December 31, 2014
First Mortgage Bonds (a) (b)	2.85%	2015 - 2043	$ 1,359
Total Long-term Debt Before Adjustments			1,359
Other			
Fair market value adjustments			(1)
Unamortized discount			(5)
Unamortized debt issuance costs			(8)
Total Long-term Debt			1,345
Less current portion of Long-term Debt			250
Total Long-term Debt, noncurrent			$ 1,095

(a) LG&E's first mortgage bonds are secured by the lien of the LG&E 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $4.2 billion and $3.7 billion at December 31, 2015 and 2014.

(b) Includes LG&E's series of first mortgage bonds that were issued to the respective trustees of tax-exempt revenue bonds to secure its respective obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amounts, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. These first mortgage bonds were issued under the LG&E 2010 Mortgage Indenture and are secured as noted in (a) above. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of LG&E. The related revenue bond documents allow LG&E to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a LIBOR index rate.

At December 31, 2015, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a term rate mode totaled $391 million. At December 31, 2015, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a variable rate mode totaled $183 million.

Several series of the tax-exempt revenue bonds are insured by monoline bond insurers whose ratings were reduced due to exposures relating to insurance of sub-prime mortgages. Of the bonds outstanding, $135 million are in the form of insured auction rate securities, wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. During 2008, interest rates increased, and LG&E experienced failed auctions when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. As noted above, the instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes.

Certain of the variable rate tax-exempt revenue bonds totaling $23 million at December 31, 2015, are subject to tender for purchase by LG&E at the option of the holder and to mandatory tender for purchase by LG&E upon the occurrence of certain events.

(c) The table reflects principal maturities only, based on stated maturities or earlier put dates.

None of the outstanding debt securities noted above have sinking fund requirements. The aggregate maturities of long-term debt, based on stated maturities or earlier put dates, for the periods 2016 through 2020 and thereafter are as follows:

2016	$	25
2017		194
2018		98
2019		40
2020		-
Thereafter		1,302
Total	$	1,659

In September 2015, LG&E issued $300 million of 3.30% First Mortgage Bonds due 2025 and $250 million of 4.375% First Mortgage Bonds due 2045. LG&E received proceeds of $298 million and $248 million, net of discounts and underwriting fees, which were used to repay short-term debt, to repay 1.625% First Mortgage Bonds that matured in November 2015 and for general corporate purposes.

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Legal Separateness

The subsidiaries of PPL are separate legal entities. PPL's subsidiaries are not liable for the debts of PPL. Accordingly, creditors of PPL may not satisfy their debts from the assets of PPL's subsidiaries absent a specific contractual undertaking by a subsidiary to pay PPL's creditors or as required by applicable law or regulation. Similarly, PPL is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of PPL's subsidiaries may not satisfy their debts from the assets of PPL or its other subsidiaries absent a specific contractual undertaking by PPL or its other subsidiaries to pay the creditors or as required by applicable law or regulation.

Similarly, the subsidiaries of LKE are each separate legal entities. These subsidiaries are not liable for the debts of LKE. Accordingly, creditors of LKE may not satisfy their debts from the assets of LKE's subsidiaries absent a specific contractual undertaking by a subsidiary to pay the creditors or as required by applicable law or regulation. Similarly, LKE is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of its subsidiaries may not satisfy their debts from the assets of LKE (or its other subsidiaries) absent a specific contractual undertaking by that parent or other subsidiary to pay such creditors or as required by applicable law or regulation.

Distributions and Related Restrictions

LKE primarily relies on dividends from its subsidiaries to fund its distributions to PPL. LG&E is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. LG&E believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. In February 2012, LG&E petitioned the FERC requesting authorization to pay dividends in the future based on retained earnings balances calculated without giving effect to the impact of purchase accounting adjustments for the acquisition of LKE by PPL. In May 2012, FERC approved the petitions with the further condition that LG&E may not pay dividends if such payment would cause its adjusted equity ratio to fall below 30% of total capitalization. Accordingly, at December 31, 2015, net assets of $1.1 billion were restricted for purposes of paying dividends to LKE, and net assets of $1.2 billion were available for payment of dividends to LKE. LG&E believes it will not be required to change its current dividend practices as a result of the foregoing requirement. Orders from the KPSC require LG&E to obtain prior consent or approval before lending amounts to PPL or LKE.

6. Acquisitions, Development and Divestitures

From time to time, LG&E evaluates opportunities for potential acquisitions, divestitures and development projects. Development projects are reexamined based on market conditions and other factors to determine whether to proceed with, modify or terminate the projects. Any resulting transactions may impact future financial results.

Development

Capacity Needs

The Cane Run Unit 7 NGCC was put into commercial operation on June 19, 2015. As a result and to meet more stringent EPA regulations, LG&E retired one coal-fired generating unit at the Cane Run plant in March 2015 and retired the remaining two coal-fired generating units at the plant in June 2015. LG&E incurred costs of $11 million directly related to these retirements including inventory write-downs and separation benefits. However, there were no gains or losses on the retirement of these units.

In December 2014, a final order was issued by the KPSC approving the request to construct a 10 MW solar generation facility at E.W. Brown. LG&E and KU began construction activities in the fourth quarter of 2015 and project the plant to be placed into commercial operation by June 2016 at a cost of approximately $30 million.

7. Leases

LG&E has entered into various agreements for the lease of office space, vehicles, land, gas storage and other equipment.

Rent - Operating Leases

Rent expense for operating leases was $12 million and $7 million for the years ended December 31, 2015 and 2014.

Total future minimum rental payments for all operating leases are estimated to be:

2016	$	14
2017		14
2018		13
2019		7
2020		4
Thereafter		10
Total	$	62

8. Retirement and Postemployment Benefits

Defined Benefits

LG&E sponsors and participates in non-contributory defined benefit pension plans. These plans are applicable to the majority of LG&E employees. The plan LG&E participates in is sponsored by LKE. LG&E is allocated a portion of the funded status and costs of the plan sponsored by LKE based on its participation in the plan, which

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management believes is reasonable. LG&E's and LKE's defined benefit pension plans were closed to new salaried and bargaining unit employees hired after December 31, 2005. Employees hired after December 31, 2005 receive additional company contributions above the standard matching contributions to their savings plans.

The majority of employees are eligible for certain health care and life insurance benefits upon retirement through a contributory plan sponsored by LKE. Postretirement health benefits may be paid from 401(h) accounts established as part of the LKE plan within the PPL Services Corporation Master Trust, funded VEBA trusts and company funds.

The following table provides the components of net periodic defined benefit costs for LG&E's pension benefit plan for the years ended December 31.

	Pension Benefits	
	2015	2014
Net periodic defined benefit costs (credits):		
Service cost	$ 1	$ 1
Interest cost	14	15
Expected return on plan assets	(20)	(19)
Amortization of:		
Prior service cost (credit)	3	2
Actuarial (gain) loss (a)	11	6
Net periodic defined benefit costs (credits)	$ 9	$ 5
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:		
Net (gain) loss	$ 8	$ 14
Prior service cost (credit)	10	9
Amortization of:		
Prior service (cost) credit	(3)	(2)
Actuarial gain (loss)	(11)	(6)
Total recognized in regulatory assets	4	15
Total recognized in net periodic benefit costs and regulatory assets	$ 13	$ 20

(a) As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between actuarial (gain)/loss calculated in accordance with LG&E's pension accounting policy and actuarial (gain)/loss calculated using a 15 year amortization period was $3 million.

For the pension plan sponsored by LG&E, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2016 are $12 million ($5 million amortization of prior service cost and $7 million amortization of actuarial loss). For the pension plan LG&E participates in, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2016 are $7 million ($2 million

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amortization of prior service cost and $5 million amortization of actuarial loss). For the other postretirement plan LG&E participates in, the estimated amount to be amortized from regulatory assets into net periodic defined benefit costs in 2016 is $1 million (amortization of prior service cost).

As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between net periodic defined benefit costs calculated in accordance with LG&E's pension accounting policy and the net periodic defined benefit costs calculated using a 15 year amortization period for gains and losses is recorded as a regulatory asset. For the pension plan sponsored by LG&E, of the costs expected to be amortized into net periodic defined benefit costs in 2016, $4 million is expected to be recorded as a regulatory asset. For the pension plan LG&E participates in, of the costs expected to be amortized into net periodic defined benefit costs in 2016, $2 million is expected to be recorded as a regulatory asset.

The net periodic defined benefit costs charged to operating expense or regulatory assets, excluding amounts charged to construction work in progress and other non-expense accounts, for LG&E’s pension benefits were $7 million and $3 million in 2015 and 2014. Allocations to LG&E for net periodic defined benefit costs charged to operating expense or regulatory assets, excluding amounts charged to construction work in progress and other non-expense accounts, for pension benefits were $5 million and $2 million in 2015 and 2014. Allocations to LG&E for net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction work in progress and other non-expense accounts, for other postretirement benefits were $4 million in both 2015 and 2014. These allocated amounts are based on LG&E’s participation in those plans, which management believes is reasonable.

For the pension plan sponsored by LG&E, of the costs charged to operating expense or regulatory assets, excluding amounts charged to construction and other non-expense accounts, $2 million was recorded as regulatory assets during 2015 representing the difference between net periodic defined benefit costs under the pension accounting policy and using a 15 year amortization period for gains and losses. An additional $2 million was recorded as a regulatory asset for this difference for the pension plan in which LG&E participates during 2015.

LKE and LG&E adopted the new mortality tables issued by the Society of Actuaries in October 2014 (RP-2014 base tables) for their defined benefit pension plans and LKE’s other postretirement benefit plan at December 31, 2014 and 2015. In addition, LKE and LG&E updated the basis for estimating projected mortality improvements and selected the IRS BB-2D two-dimensional improvement scales on a generational basis for all their defined benefit pension plans and LKE’s other postretirement benefit plan. These new mortality assumptions reflect the recognition of both improved life expectancies and the expectation of continuing improvements in life expectancies. The use of the new base tables and improvement scale resulted in an increase to LG&E’s defined benefit pension obligation, an increase to future expense and a decrease in funded status. The use of the new base tables and improvement scale also resulted in an increased allocation from LKE to LG&E for defined benefit pension and other postretirement benefit obligations and future expense and a decrease in allocated funded status.

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For the pension plan sponsored by LG&E, the following weighted-average assumptions were used in the valuation of the benefit obligations at December 31.

	Pension Benefits	
	2015	2014
Discount rate	4.49%	4.20%

For the pension plan sponsored by LG&E, the following weighted-average assumptions were used to determine the net periodic defined benefit costs for the years ended December 31.

	Pension Benefits	
	2015	2014
Discount rate	4.20%	5.13%
Expected return on plan assets (a)	7.00%	7.10%

(a) The expected long-term rates of return for pension and other postretirement benefits are based on management's projections using a best-estimate of expected returns, volatilities and correlations for each asset class. Each plan's specific current and expected asset allocations are also considered in developing a reasonable return assumption.

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The funded status of LG&E's plan at December 31 was as follows:

	Pension Benefits	
	2015	**2014**
Change in Benefit Obligation		
Benefit Obligation, beginning of period	$ 331	$ 291
Service cost	1	1
Interest cost	14	15
Plan amendments (a)	10	9
Actuarial (gain) loss	(15)	36
Gross benefits paid (b)	(15)	(21)
Benefit Obligation, end of period	$ 326	$ 331
Change in Plan Assets		
Plan assets at fair value, beginning of period	301	281
Actual return on plan assets	(2)	41
Employer contributions	13	-
Gross benefits paid (b)	(15)	(21)
Plan assets at fair value, end of period	297	301
Funded Status, end of period	$ (29)	$ (30)
Amounts recognized in the Balance Sheets consist of:		
Noncurrent liability	(29)	(30)
Net amount recognized, end of period	$ (29)	$ (30)
Amounts recognized in regulatory assets (pre-tax) consists of:		
Prior service cost (credit)	$ 29	$ 22
Net actuarial (gain) loss	95	98
Total	$ 124	$ 120
Total accumulated benefit obligation for defined benefit pension plan	$ 326	$ 330

(a) The plan was amended in December 2015 allowing terminated vested participants to elect to receive their accrued pension benefit as a one-time lump-sum payment effective January 1, 2016. The projected benefit obligation increased by $10 million as a result of the amendment.

The plan was amended in December 2014 to enhance the early retirement factors for all plan participants retiring on or after January 1, 2015. The projected benefit obligation increased by $9 million as a result of the amendment.

(b) LG&E's pension plan offered a limited-time program in 2014 during which terminated vested participants could elect to receive their accrued pension benefit as a one-time lump-sum payment. The gross benefits paid includes $8 million of lump-sum cash payments made to terminated vested participants in 2014 in connection with this offering.

LG&E's pension plan had projected and accumulated benefit obligations in excess of plan assets at December 31, 2015 and 2014.

In addition to the plan it sponsors, LG&E is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to LG&E for pension benefits resulted in a liability of $26 million and $27 million at December 31, 2015 and 2014. Allocations to LG&E for other postretirement benefits resulted in a liability of $77 million and $85 million at December 31, 2015 and 2014.

Plan Assets - Pension Plans

The pension plans sponsored by LKE and LG&E are invested in the PPL Services Corporation Master Trust (the Master Trust) that also includes 401(h) accounts that are restricted for certain other postretirement benefit obligations of PPL and LKE. The investment strategy for the Master Trust is to achieve a risk-adjusted return on a mix of assets that, in combination with LG&E's funding policy, will ensure that sufficient assets are available to provide long-term growth and liquidity for benefit payments, while also managing the duration of the assets to complement the duration of the liabilities. The Master Trust benefits from a wide diversification of asset types, investment fund strategies and external investment fund managers, and therefore has no significant concentration of risk.

The investment policy of the Master Trust outlines investment objectives and defines the responsibilities of the EBPB, external investment managers, investment advisor and trustee and custodian. The investment policy is reviewed annually by PPL's Board of Directors.

The EBPB created a risk management framework around the trust assets and pension liabilities. This framework considers the trust assets as being composed of three sub-portfolios: growth, immunizing and liquidity portfolios. The growth portfolio is comprised of investments that generate a return at a reasonable risk, including equity securities, certain debt securities and alternative investments. The immunizing portfolio consists of debt securities, generally with long durations, and derivative positions. The immunizing portfolio is designed to offset a portion of the change in the pension liabilities due to changes in interest rates. The liquidity portfolio consists primarily of cash and cash equivalents.

Target allocation ranges have been developed for each portfolio on a plan basis based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio on a plan basis, and seeks to obtain a target portfolio that emphasizes reduction of risk of loss from market volatility. In pursuing that goal, the EBPB establishes revised guidelines from time to time. EBPB

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investment guidelines as of the end of 2015 are presented below.

The asset allocation for the trust and the target allocation by portfolio at December 31 are as follows:

	Percentage of Trust Assets 2015 (a)	2015 Target Asset Allocation (a) Weighted Average
Growth Portfolio	**51%**	**50%**
Equity securities	25%	
Debt securities (b)	13%	
Alternative investments	13%	
Immunizing Portfolio	**47%**	**48%**
Debt securities (b)	42%	
Derivatives	5%	
Liquidity Portfolio	**2%**	**2%**
Total	100%	100%

	Percentage of Trust Assets 2014
Growth Portfolio	**51%**
Equity securities	26%
Debt securities (b)	13%
Alternative investments	12%
Immunizing Portfolio	**47%**
Debt securities (b)	44%
Derivatives	3%
Liquidity Portfolio	**2%**
Total	100%

(a) Allocations exclude consideration of a group annuity contract held by the LG&E and KU Retirement Plan.
(b) Includes commingled debt funds, which are treated as debt securities for asset allocation purposes.

LG&E’s and LKE’s pension plan assets are invested solely in the Master Trust, which is fully disclosed below. The fair value of LG&E’s plan's assets of $297 million and $301 million at December 31, 2015 and 2014 represents an interest of approximately 9% and 6% in the Master Trust. The fair value of LKE’s plans assets of $1.3 billion at December 31, 2015 and 2014 represents an interest of approximately 40% and 28% in the Master Trust.

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The fair value of net assets in the Master Trust by asset class and level within the fair value hierarchy was:

	December 31, 2015			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 225	$ 225	$ -	$ -
Equity securities				
U.S.:				
Large-cap	87	87	-	-
Large-cap fund measured at NAV (a)	197	-	-	-
Small-cap	85	85	-	-
International equity fund at NAV (a)	454	-	-	-
Commingled debt measured at NAV (a)	514	-	-	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	501	492	9	-
Residential/commercial backed securities	3	-	3	-
Corporate	747	-	737	10
International government	4	-	4	-
Other	7	-	7	-
Alternative investments				
Commodities measured at NAV (a)	70	-	-	-
Real estate measured at NAV (a)	118	-	-	-
Private equity measured at NAV (a)	81	-	-	-
Hedge funds measured at NAV (a)	171	-	-	-
Derivatives:				
Interest rate swaps and swaptions	80	-	80	-
Other	11	-	11	-
Insurance contracts	32	-	-	32
PPL Services Corporation Master Trust assets, at fair value	$ 3,387	$ 889	$ 851	$ 42
Receivables and payables, net (b)	(49)			
401(h) account restricted for other postretirement benefit obligations	(111)			
Total PPL Services Corporation Master Trust pension assets	$ 3,227			

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	December 31, 2014			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 246	$ 246	$ -	$ -
Equity securities				
U.S.:				
Large-cap	114	114	-	-
Large-cap fund measured at NAV (a)	318	-	-	-
Small-cap	145	145	-	-
International equity fund at NAV (a)	615	-	-	-
Commingled debt measured at NAV (a)	818	-	-	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	723	706	17	-
Residential/commercial backed securities	2	-	2	-
Corporate	1,109	-	1,088	21
International government	8	-	8	-
Other	9	-	9	-
Alternative investments				
Commodities measured at NAV (a)	90	-	-	-
Real estate measured at NAV (a)	148	-	-	-
Private equity measured at NAV (a)	104	-	-	-
Hedge funds measured at NAV (a)	223	-	-	-
Derivatives:				
Interest rate swaps and swaptions	92	-	92	-
Other	12	-	12	-
Insurance contracts	33	-	-	33
PPL Services Corporation Master Trust assets, at fair value	$ 4,809	$ 1,211	$ 1,228	$ 54
Receivables and payables, net (b)	(41)			
401(h) account restricted for other postretirement benefit obligations	(136)			
Total PPL Services Corporation Master Trust pension assets	$ 4,632			

(a) In accordance with accounting guidance certain investments that are measured at fair value using the net asset value per share (NAV), or its equivalent, practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.

(b) Receivables and payables represent amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

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A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2015 is as follows:

	Corporate debt	Insurance contracts	Total
Balance at beginning of period	$ 21	$ 33	$ 54
Actual return on plan assets			
Relating to assets still held at the reporting date	-	2	2
Relating to assets sold during the period	(1)	-	(1)
Purchases, sales and settlements	(10)	(3)	(13)
Balance at end of period	$ 10	$ 32	$ 42

A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2014 is as follows:

	Corporate debt	Insurance contracts	Total
Balance at beginning of period	$ 23	$ 37	$ 60
Actual return on plan assets			
Relating to assets still held at the reporting date	(1)	1	-
Relating to assets sold during the period	(1)	-	(1)
Purchases, sales and settlements	-	(5)	(5)
Balance at end of period	$ 21	$ 33	$ 54

The fair value measurements of cash and cash equivalents are based on the amounts on deposit.

The market approach is used to measure fair value of equity securities. The fair value measurements of equity securities (excluding commingled funds), which are generally classified as Level 1, are based on quoted prices in active markets. These securities represent actively and passively managed investments that are managed against various equity indices and exchange traded funds (ETFs).

Investments in commingled equity and debt funds are categorized as equity securities. Investments in commingled equity funds include funds that invest in U.S. and international equity securities. Investments in commingled debt funds include funds that invest in a diversified portfolio of emerging market debt obligations, as well as funds that invest in investment grade long-duration fixed-income securities.

The fair value measurements of debt securities are generally based on evaluations that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences. The fair value of debt securities is generally measured using a market approach,

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including the use of pricing models which incorporate observable inputs. Common inputs include benchmark yields, relevant trade data, broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as payment data, future predicted cash flows, collateral performance and new issue data. For the Master Trust, these securities represent investments in securities issued by U.S. Treasury and U.S. government sponsored agencies; investments securitized by residential mortgages, auto loans, credit cards and other pooled loans; investments in investment grade and non-investment grade bonds issued by U.S. companies across several industries; investments in debt securities issued by foreign governments and corporations.

Investments in commodities represent ownership interest of a commingled fund that is invested in a portfolio of exchange-traded futures and forward contracts in commodities to obtain broad exposure to all principal groups in the global commodity markets, including energies, agriculture and metals (both precious and industrial) using proprietary commodity trading strategies. Redemptions can be made the 15^{th} calendar day and the last calendar day of the month with a specified notification period. The fund's fair value is based upon a value as calculated by the fund's administrator.

Investments in real estate represent an investment in a partnership whose purpose is to manage investments in core U.S. real estate properties diversified geographically and across major property types (e.g., office, industrial, retail, etc.). The manager is focused on properties with high occupancy rates with quality tenants. This results in a focus on high income and stable cash flows with appreciation being a secondary factor. Core real estate generally has a lower degree of leverage when compared with more speculative real estate investing strategies. The partnership has limitations on the amounts that may be redeemed based on available cash to fund redemptions. Additionally, the general partner may decline to accept redemptions when necessary to avoid adverse consequences for the partnership, including legal and tax implications, among others. The fair value of the investment is based upon a partnership unit value.

Investments in private equity represent interests in partnerships in multiple early-stage venture capital funds and private equity fund of funds that use a number of diverse investment strategies. Four of the partnerships have limited lives of ten years, while the fifth has a life of 15 years, after which liquidating distributions will be received. Prior to the end of each partnership's life, the investment cannot be redeemed with the partnership; however, the interest may be sold to other parties, subject to the general partner's approval. The Master Trust has unfunded commitments of $27 million that may be required during the lives of the partnerships. Fair value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

Investments in hedge funds represent investments in three hedge fund of funds. Hedge funds seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under most market conditions. Major investment strategies for the hedge fund of funds include long/short equity, market neutral, distressed debt, and relative value. Generally, shares may be redeemed within 60 to 95 days with prior written notice. The funds are subject to short term lockups and have limitations on the amount that may be withdrawn based on a percentage of the total net asset value of the fund, among other restrictions. All withdrawals are subject to the general partner's approval. The fair value for two of the funds has been estimated using the net asset value per share and the third fund's fair

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value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

The fair value measurements of derivative instruments utilize various inputs that include quoted prices for similar contracts or market-corroborated inputs. In certain instances, these instruments may be valued using models, including standard option valuation models and standard industry models. These securities primarily represent investments in interest rate swaps and swaptions (the option to enter into an interest rate swap) which are valued based on the swap details, such as swap curves, notional amount, index and term of index, reset frequency, volatility and payer/receiver credit ratings.

Insurance contracts, classified as Level 3, represent an investment in an immediate participation guaranteed group annuity contract. The fair value is based on contract value, which represents cost plus interest income less distributions for benefit payments and administrative expenses.

Plan Assets - Other Postretirement Benefit Plans

LKE's other postretirement benefit plan is invested primarily in a 401(h) account, as disclosed in the PPL Services Corporation Master Trust, with insignificant amounts invested in money market funds within VEBA trusts for liquidity.

Expected Cash Flows - Defined Benefit Plans

LG&E's defined benefit pension plan has the option to utilize available prior year credit balances to meet current and future contribution requirements. However, LG&E contributed $7 million to its pension plan in January 2016. LG&E also contributed $5 million to LKE’s pension plan on behalf of LG&E employees in January 2016.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the plan for LG&E retirees.

	LG&E Sponsored Pensions	Allocated from LKE Pension Plan
2016	$ 23	$ 15
2017	25	15
2018	24	16
2019	25	16
2020	25	16
2020-2025	111	84

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Savings Plans

Substantially all employees of LG&E are eligible to participate in deferred savings plans (401(k)s). Employer contributions to the plans were $5 million each in 2015 and 2014.

9. Jointly Owned Facilities

At December 31, 2015 and 2014, the Balance Sheets reflect the owned interests in the facilities listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
December 31, 2015				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 12	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	47	10	1
Trimble County Unit 1	75.00%	399	44	6
Trimble County Unit 2	14.25%	210	28	12
Trimble County Units 5-6	29.00%	29	6	-
Trimble County Units 7-10	37.00%	71	14	-
Cane Run Unit 7	22.00%	115	1	1
E.W. Brown Solar Unit	39.00%	-	-	4
December 31, 2014				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 10	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	47	7	-
Trimble County Unit 1	75.00%	309	51	59
Trimble County Unit 2	14.25%	205	23	15
Trimble County Units 5-6	29.00%	29	5	-
Trimble County Units 7-10	37.00%	70	11	-
Cane Run Unit 7	22.00%	-	-	113

LG&E provides its own funding for its share of each of the above facilities. LG&E receives a portion of the total output of the generating plants equal to its percentage ownership. The share of fuel and other operating costs associated with the plants is included in the corresponding operating expenses on the Statements of Income.

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10. Commitments and Contingencies

Energy Purchases Commitments

LG&E enters into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's gas supply operations. These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Coal	2022
Coal Transportation and Fleeting Services	2024
Natural Gas Storage and Transporation	2024
Natural Gas Transportation	2026

LG&E has a power purchase agreement with OVEC expiring in June 2040. See "Guarantees and Other Assurances" below for information on the OVEC power purchase contract. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses are projected as follows:

2016	$	18
2017		19
2018		19
2019		19
2020		20
Thereafter		435
	$	530

In addition, LG&E had total energy purchases under the OVEC power purchase agreement of $15 million and $17 million for the years ended December 31, 2015 and 2014.

Legal Matters

LG&E is involved in legal proceedings, claims and litigation in the ordinary course of business. LG&E cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

Cane Run Environmental Claims

In December 2013, six residents, on behalf of themselves and others similarly situated, filed a class action complaint against LG&E and PPL in the U.S. District Court for the Western District of Kentucky alleging

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violations of the Clean Air Act and RCRA. In addition, these plaintiffs assert common law claims of nuisance, trespass and negligence. These plaintiffs seek injunctive relief and civil penalties, plus costs and attorney fees, for the alleged statutory violations. Under the common law claims, these plaintiffs seek monetary compensation and punitive damages for property damage and diminished property values for a class consisting of residents within four miles of the plant. In their individual capacities, these plaintiffs seek compensation for alleged adverse health effects. In response to a motion to dismiss filed by LG&E and PPL, in July 2014, the court dismissed the plaintiffs' RCRA claims and all but one Clean Air Act claim, but declined to dismiss their common law tort claims. Upon motion of LG&E and PPL, the district court certified for appellate review the issue of whether the state common law claims are preempted by federal statute. In December 2014, the U.S. Court of Appeals for the Sixth Circuit issued an order granting appellate review regarding the above matter. Oral argument before the Sixth Circuit was held in August 2015. In November 2015, the Sixth Circuit issued an opinion affirming the District Court's ruling that plaintiffs' state law claims are not preempted by the Clean Air Act and remanding the matter to the District Court for further proceedings. Certain discovery matters are currently before the District Court. LG&E cannot predict the outcome of this matter. LG&E retired one coal-fired unit at the Cane Run plant in March 2015 and the remaining two coal-fired units at the plant in June 2015.

Mill Creek Environmental Claims

In May 2014, the Sierra Club filed a citizen suit against LG&E in the U.S. District Court for the Western District of Kentucky for alleged violations of the Clean Water Act. The Sierra Club alleges that various discharges at the Mill Creek plant constitute violations of the plant's water discharge permit. The Sierra Club seeks civil penalties, injunctive relief, costs and attorney's fees. In August 2015, the Court denied cross-motions for summary judgment filed by both parties and directed the parties to proceed with discovery. Discovery proceedings are underway and the parties have also conducted limited settlement discussions in the matter. LG&E cannot predict the outcome of this matter or the potential impact on the operations of the Mill Creek plant, including increased capital or operating costs, if any, but believes the plant is operating in compliance with the permits.

Trimble County Unit 2 Air Permit

The Sierra Club and other environmental groups petitioned the Kentucky Environmental and Public Protection Cabinet to overturn the air permit issued for the Trimble County Unit 2 baseload coal-fired generating unit, but the agency upheld the permit in an order issued in September 2007. In response to subsequent petitions by environmental groups, the EPA ordered certain non-material changes to the permit which, in January 2010, were incorporated into a final revised permit issued by the Kentucky Division for Air Quality. In March 2010, the environmental groups petitioned the EPA to object to the revised state permit. Until the EPA issues a final ruling on the pending petition and all available appeals are exhausted, LG&E cannot predict the outcome of this matter or the potential impact on the operations of the Trimble County plant, including increased capital or operating costs, if any.

Trimble County Water Discharge Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the

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Kentucky Energy and Environment Cabinet (KEEC) challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County plant. In November 2010, the KEEC issued a final order upholding the permit which was subsequently appealed by the environmental groups. In September 2013, the Franklin Circuit Court reversed the KEEC order upholding the permit and remanded the permit to the agency for further proceedings. LG&E and the KEEC appealed the order to the Kentucky Court of Appeals. In July 2015, the Court of Appeals upheld the lower court ruling. LG&E and the KEEC have moved for discretionary review by the Kentucky Supreme Court. On February 10, 2016, the Kentucky Supreme Court issued an order granting discretionary review. LG&E is unable to predict the outcome of this matter or the potential impact on the operations of the Trimble County plant, including increased capital or operating costs, if any.

Regulatory Issues

See Note 4 for information on regulatory matters related to utility rate regulation.

Electricity - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations.

LG&E monitors its compliance with the Reliability Standards and continues to self-report or self-log potential violations of certain applicable reliability requirements and submit accompanying mitigation plans, as required. The resolution of a small number of potential violations is pending. Any Regional Reliability Entity (including RFC or SERC) determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC.

In the course of implementing its programs to ensure compliance with the Reliability Standards, certain other instances of potential non-compliance may be identified from time to time. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

Environmental Matters

Due to the environmental issues discussed below or other environmental matters, it may be necessary for LG&E to modify, curtail, replace or cease operation of certain facilities or performance of certain operations to comply with statutes, regulations and other requirements of regulatory bodies or courts. In addition, legal challenges to new environmental permits or rules add to the uncertainty of estimating the future cost of these permits and rules.

LG&E is entitled to recover, through the ECR mechanism, certain costs of complying with the Clean Air Act, as

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amended, and those federal, state or local environmental requirements applicable to coal combustion wastes and by-products from facilities that generate electricity from coal in accordance with approved compliance plans. Costs not covered by the ECR mechanism are subject to rate recovery before the KPSC or the FERC. LG&E can provide no assurances as to the ultimate outcome of future environmental or rate proceedings before regulatory authorities.

<u>Air</u>

The Clean Air Act, which regulates air pollutants from mobile and stationary sources, has a significant impact on the operation of fossil fuel plants. The Clean Air Act requires the EPA periodically to review and establish concentration levels in the ambient air for six criteria pollutants to protect public health and welfare. These concentration levels are known as NAAQS. The six criteria pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter and sulfur dioxide.

Federal environmental regulations of these criteria pollutants require states to adopt implementation plans, known as state implementation plans, for certain pollutants, which detail how the state will attain the standards that are mandated by the relevant law or regulation. Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas), and must develop a state implementation plan both to bring non-attainment areas into compliance with the NAAQS and to maintain good air quality in attainment areas. In addition, for attainment of ozone and fine particulates standards, states in the eastern portion of the country, including Kentucky, are subject to a regional program developed by the EPA known as the Cross-State Air Pollution Rule. The NAAQS, future revisions to the NAAQS and state implementation plans implementing them, or future revisions to regional programs, may require installation of additional pollution controls, the costs of which LG&E believes are subject to cost recovery.

Although LG&E does not currently anticipate significant costs to comply with these programs, changes in market or operating conditions could result in different costs than anticipated.

National Ambient Air Quality Standards (NAAQS)

Under the Clean Air Act, the EPA is required to reassess the NAAQS for certain air pollutants on a five-year schedule. In 2008, the EPA revised the NAAQS for ozone and proposed to further strengthen the standard in November 2014. The EPA released a new ozone standard on October 1, 2015. The states and EPA will determine attainment with the new ozone standard through review of relevant ambient air monitoring data, with attainment or nonattainment designations scheduled no later than October 2017. States are also obligated to address interstate transport issues associated with new ozone standards through the establishment of "good neighbor" state implementation plans for those states that are found to contribute significantly to another states' non-attainment. States that are not in the ozone transport region, including Kentucky, are working together to evaluate further nitrogen oxide reductions from fossil-fueled plants with SCRs. The nature and timing of any additional reductions resulting from these evaluations cannot be predicted at this time.

In 2010, the EPA finalized revised NAAQS for sulfur dioxide and required states to identify areas that meet those standards and areas that are in "non-attainment". In July 2013, the EPA finalized non-attainment designations for parts of the country, including part of Jefferson County in Kentucky. Attainment must be

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achieved by 2018. LG&E anticipates that certain previously required compliance measures, such as upgraded or new sulfur dioxide scrubbers at certain plants and the retirement of coal-fired generating units at LG&E's Cane Run plant, will help to achieve compliance with the new sulfur dioxide and ozone standards. If additional reductions are required, the costs could be significant.

Mercury and Air Toxics Standards (MATS)

In February 2012, the EPA finalized the MATS rule requiring reductions of mercury and other hazardous air pollutants from fossil-fuel fired power plants, with an effective date of April 16, 2012. The MATS rule was challenged by industry groups and states and was upheld by the U.S. Court of Appeals for the D. C. Circuit Court (D.C. Circuit Court) in April 2014. A group of states subsequently petitioned the U.S. Supreme Court (Supreme Court) to review this decision and in June 2015, the Supreme Court held that the EPA failed to properly consider costs when deciding to regulate hazardous air emissions from power plants under MATS. The Court remanded the matter to the D.C. Circuit Court, which in December 2015 remanded the rule to EPA without vacating it. EPA has proposed a supplemental finding regarding costs of the rule and has announced that it intends to make a final determination in 2016. The EPA's MATS rule remains in effect during the pendency of the ongoing proceedings.

LG&E has installed significant controls in connection with the MATS rule and in conjunction with compliance with other environmental requirements, including fabric-filter baghouses, upgraded scrubbers or chemical additive systems for which appropriate KPSC authorization and/or ECR treatment has been received. LG&E is currently seeking KPSC approval for a compliance plan providing for installation of additional MATS-related controls, the cost of which is currently estimated at $5 million. LG&E cannot predict the outcome of the MATS rule or its potential impact, if any, on plant operations, rate treatment or future capital or operating needs. See Note 4 for additional information.

New Source Review (NSR)

The NSR litigation brought by EPA, states and environmental groups against coal-fired generating plants in past years continues to proceed through the courts. Although none of this litigation directly involves LG&E, it can influence the permitting of large capital projects at LG&E's power plants, the costs of which cannot presently be determined but could be significant.

Climate Change

There is continuing momentum to address climate change. Most recently, in December 2015, 195 nations, including the U.S., signed the Paris Agreement on Climate which establishes a comprehensive framework for the reduction of GHG emissions from both developed and developing nations. Although the agreement does not establish binding reduction requirements, it requires each nation to prepare, communicate, and maintain GHG reduction commitments. Based on EPA's Clean Power Plan described below, the U.S. has committed to an initial reduction target of 26% to 28% below 2005 levels by 2025.

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The EPA's Rules under Section 111 of the Clean Air Act

As further described below, the EPA finalized rules imposing greenhouse gas emission standards for both new and existing power plants. The EPA has also issued a proposed federal implementation plan that would apply to any states that fail to submit an acceptable state implementation plan under these rules. The EPA's authority to promulgate these regulations under Section 111 of the Clean Air Act has been challenged in the D.C. Circuit Court by several states and industry groups. On February 9, 2016, the Supreme Court stayed the rule for existing plants (the Clean Power Plan) pending the D.C. Circuit Court's review and subsequent review by the Supreme Court if a writ of certiorari is filed and granted.

The EPA's rule for new power plants imposes separate emission standards for coal and natural gas units based on the application of different technologies. The coal standard is based on the application of partial carbon capture and sequestration technology, but because this technology is not presently commercially available, the rule effectively precludes the construction of new coal-fired plants. The standard for NGCC power plants is the same as the EPA proposed in 2012 and is not continuously achievable. The preclusion of new coal-fired plants and the compliance difficulties posed for new natural gas-fired plants could have a significant industry-wide impact.

The EPA's Clean Power Plan

The EPA's rule for existing power plants, referred to as the Clean Power Plan, was published in the Federal Register in October 2015. The Clean Power Plan contains state-specific rate-based and mass-based reduction goals and guidelines for the development, submission and implementation of state implementation plans to achieve the state goals. State-specific goals were calculated from 2012 data by applying EPA's broad interpretation and definition of the BSER, resulting in the most stringent targets to be met in 2030, with interim targets to be met beginning in 2022. The EPA believes it has offered some flexibility to the states as to how their compliance plans can be crafted, including the option to use a rate-based approach (limit emissions per megawatt hour) or a mass-based approach (limit total tons of emissions per year), and the option to demonstrate compliance through emissions trading and multi-state collaborations. Under the rate-based approach, Kentucky would need to make a 41% reduction from its 2012 emissions rate and under a mass-based approach it would need to make a 36% reduction. These reductions are significantly greater than initially proposed and present significant challenges to the state. If the Clean Power Plan is ultimately upheld and Kentucky fails to develop an approvable implementation plan by the applicable deadline, the EPA would impose a federal implementation plan that could be more stringent than what the state plan might provide. Depending on the provisions of the Kentucky implementation plan, LG&E may need to modify its current portfolio of generating assets during the next decade and/or participate in an allowance trading program.

LG&E is participating in the ongoing regulatory processes at the state and federal level in an effort to provide input into the state or federal implementation plan that will govern reductions in Kentucky. Various states, industry groups, and individual companies including LKE have filed petitions for reconsideration with EPA and petitions for review with the D.C. Circuit Court challenging the Clean Power Plan. LG&E cannot predict the outcome of this matter or the potential impact, if any, on plant operations, or future capital or operating needs. LG&E believes that the costs, which could be significant, would be subject to cost recovery.

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In April 2014, the Kentucky General Assembly passed legislation which limits the measures that the Kentucky Energy and Environment Cabinet may consider in setting performance standards to comply with the EPA's regulations governing GHG emissions from existing sources. The legislation provides that such state GHG performance standards shall be based on emission reductions, efficiency measures, and other improvements available at each power plant, rather than renewable energy, end-use energy efficiency, fuel switching and re-dispatch. These statutory restrictions may make it more difficult for Kentucky to achieve the GHG reduction levels that the EPA has established for Kentucky.

<u>Water/Waste</u>

Coal Combustion Residuals (CCRs)

On April 17, 2015, the EPA published its final rule regulating CCRs. CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. The rule became effective on October 19, 2015. It imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. Under the rule, the EPA will regulate CCRs as non-hazardous under Subtitle D of RCRA and allow beneficial use of CCRs, with some restrictions. The rule's requirements for covered CCR impoundments and landfills include implementation of groundwater monitoring and commencement or completion of closure activities generally between three and ten years from certain triggering events. This self-implementing rule requires posting of compliance documentation on a publicly accessible website and is enforceable solely through citizen suits. LG&E is also subject to state rules applicable to CCR management which may potentially be modified to reflect some or all requirements of the federal rule.

LG&E is currently pursuing KPSC approval for a compliance plan providing for closure of impoundments at the Mill Creek and Trimble County stations, and construction of process water management facilities at those plants. LG&E currently estimate the cost of these CCR compliance measures at $311 million. See Note 4 for additional information.

In connection with the final CCR rule, LG&E recorded increases to existing AROs during 2015. See Note 15 for additional information. Further increases to AROs or changes to current capital plans or to operating costs may be required as estimates are refined based on closure developments, groundwater monitoring results, and regulatory or legal proceedings. Costs relating to this rule are subject to rate recovery.

Clean Water Act

Regulations under the federal Clean Water Act dictate permitting and mitigation requirements for many of LG&E's construction projects. Many of those requirements relate to power plant operations, including requirements related to the treatment of pollutants in effluents prior to discharge, the temperature of effluent discharges and the location, design and construction of cooling water intake structures at generating facilities, standards intended to protect aquatic organisms by reducing capture in the screens attached to cooling water intake structures (impingement) at generating facilities and the water volume brought into the facilities (entrainment). The requirements could impose significant costs which are subject to rate recovery.

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Effluent Limitations Guidelines (ELGs)

On September 30, 2015, the EPA released its final effluent limitations guidelines for wastewater discharge permits for new and existing steam electric generating facilities. The rule provides strict technology-based discharge limitations for control of pollutants in scrubber wastewater, fly ash and bottom ash transport water, mercury control wastewater, gasification wastewater, and combustion residual leachate. The new guidelines require deployment of additional control technologies providing physical, chemical, and biological treatment of wastewaters. The guidelines also mandate operational changes including "no discharge" requirements for fly ash and bottom ash transport waters and mercury control wastewaters. The implementation date for individual generating stations will be determined by the states on a case-by-case basis according to criteria provided by the EPA, but the requirements of the rule must be fully implemented no later than 2023. It has not been decided how Kentucky intends to integrate the ELGs into its routine permit renewal process. LG&E continues to assess the requirements of this complex rule to determine available compliance strategies. LG&E is unable to fully estimate compliance costs or timing at this time although certain preliminary estimates are included in current capital forecasts, for applicable periods. Costs to comply with ELGs or other discharge limits, which are expected to be significant, are subject to rate recovery.

Clean Water Act Section 316(b)

The EPA's final 316(b) rule for existing facilities became effective in October 2014, and regulates cooling water intake structures and their impact on aquatic organisms. States are allowed broad discretion to make site-specific determinations under the rule. The rule requires existing facilities to choose between several options to reduce the impact to aquatic organisms that become trapped against water intake screens (impingement) and to determine the intake structure's impact on aquatic organisms pulled through a plant's cooling water system (entrainment). Plants equipped with closed-cycle cooling, an acceptable option, would likely not incur substantial costs. Once-through systems would likely require additional technology to comply with the rule. Mill Creek Unit 1 is the only unit expected to be impacted. LG&E is evaluating compliance strategies but do not presently expect the compliance costs, which are subject to rate recovery, to be significant.

Waters of the United States (WOTUS)

The U.S. Court of Appeals for the Sixth Circuit has issued a stay of EPA's rule on the definition of WOTUS pending the court's review of the rule. The effect of the stay is that the WOTUS rule is not currently in effect anywhere in the United States. The ultimate outcome of the court's review of the rule remains uncertain. LG&E does not expect the rule to have a significant impact on its operations.

Other Issues

The EPA is reassessing its polychlorinated biphenyls (PCB) regulations under the Toxic Substance Control Act, which currently allow certain PCB articles to remain in use. In April 2010, the EPA issued an Advanced Notice of Proposed Rulemaking for changes to these regulations. This rulemaking could lead to a phase-out of all or some PCB-containing equipment. The EPA has postponed the release of the revised regulations to March 2016. LG&E cannot predict at this time the outcome of these proposed EPA regulations and what impact, if any, they would have on its facilities, but the costs could be significant.

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Superfund and Other Remediation

LG&E is investigating, responding to agency inquiries, remediating, or have completed the remediation of, several sites that were not addressed under a regulatory program such as Superfund, but for which LG&E may be liable for remediation. These include a number of former coal gas manufacturing plants previously owned or operated or currently owned by predecessors or affiliates of LG&E. To date, the costs of these sites have not been significant.

There are additional sites, formerly owned or operated by LG&E predecessors or affiliates. LG&E lacks information on the conditions of such additional sites and are therefore unable to estimate any potential liability it may have or a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require LG&E to take more extensive assessment and remedial actions at former coal gas manufacturing plants. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, LG&E undertakes remedial action in response to notices of violations, spills or other releases at various on-site and off-site locations, negotiate with the EPA and state and local agencies regarding actions necessary for compliance with applicable requirements, negotiate with property owners and other third parties alleging impacts from LG&E's operations and undertake similar actions necessary to resolve environmental matters that arise in the course of normal operations. Based on analyses to date, resolution of these environmental matters is not expected to have a significant adverse impact on LG&E's operations.

Future cleanup or remediation work at sites currently under review, or at sites not currently identified, may result in significant additional costs. Insurance policies maintained by LG&E may be applicable to certain of the costs or other obligations related to these matters but the amount of insurance coverage or reimbursement cannot be estimated or assured.

Other

Guarantees and Other Assurances

In the normal course of business, LG&E enters into agreements that provide financial performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees, stand-by letters of credit issued by financial institutions and surety bonds issued by insurance companies. These agreements are entered into primarily to support or enhance the creditworthiness attributed to a subsidiary on a stand-alone basis or to facilitate the commercial activities in which these subsidiaries engage.

Pursuant to the OVEC power purchase contract, LG&E is obligated to pay for its share of OVEC's excess debt service, post-retirement and decommissioning costs, as well as any shortfall from amounts currently included within a demand charge designed and currently expected to cover these costs over the term of the contract. LG&E's proportionate share of OVEC's outstanding debt was $86 million at December 31, 2015. The maximum exposure and the expiration date of these potential obligations are not presently determinable. See "Energy Purchases, Energy Sales and Other Commitments" above for additional information on the OVEC power purchase contract.

LG&E provides other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries, including LG&E, maintains insurance that covers liability assumed under contract for bodily injury and property damage. The coverage provides maximum aggregate coverage of $225 million. This insurance may be applicable to obligations under certain of these contractual arrangements.

11. Related Party Transactions

Wholesale Sales and Purchases

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. When LG&E has excess generation capacity after serving its own retail customers and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail customers and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost plus any split savings. Savings realized from such intercompany transactions are shared equally between both companies. The volume of energy each company has to sell to the other is dependent on its retail customers' needs and its available generation.

Support Costs

LKS provides LG&E with administrative, management and support services. The costs of these services are charged to LG&E as direct support costs. General costs that cannot be directly attributed to a specific LKE subsidiary are allocated and charged to LG&E and other subsidiaries as indirect support costs. LKS bases its indirect allocations on the subsidiaries' number of employees, total assets, revenues, number of customers and/or other statistical information.

LKS charged LG&E $155 million and $140 million for the years ended December 31, 2015 and 2014, including amounts applied to accounts that are further distributed between capital and expense on LG&E’s books, based on methods that are believed to be reasonable.

In addition to the charges for services noted above, LKS makes payments on behalf of LG&E for fuel purchases and other costs for products or services provided by third parties. LG&E and KU also provide services to each other and to LKS. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between LKE and LG&E are reimbursed through LKS.

Intercompany Derivatives

Periodically, LG&E enters into forward-starting interest rate swaps with PPL. These hedging instruments have terms identical to forward-starting swaps entered into by PPL with third parties. See Note 13 for additional information on intercompany derivatives.

Other

See Note 1 for discussions regarding the intercompany tax sharing agreement. See Note 8 for discussions regarding intercompany allocations associated with defined benefits.

12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). A market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models), and/or a cost approach (generally, replacement cost) are used to measure the fair value of an asset or liability, as appropriate. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk. The fair value of a group of financial assets and liabilities is measured on a net basis. Transfers between levels are recognized at end-of-reporting-period values. During 2015 and 2014, there were no transfers between Level 1 and Level 2. See Note 1 for information on the levels in the fair value hierarchy.

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Recurring Fair Value Measurements

The assets and liabilities measured at fair value were:

	December 31, 2015			
	Total	**Level 1**	**Level 2**	**Level 3**
Assets				
Cash and cash equivalents	$ 19	$ 19	$ -	$ -
Cash collateral posted to counterparties (a)	9	9	-	-
Total assets	$ 28	$ 28	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 47	$ -	$ 47	$ -
Total price risk management liabilities	$ 47	$ -	$ 47	$ -

	December 31, 2014			
	Total	**Level 1**	**Level 2**	**Level 3**
Assets				
Cash and cash equivalents	$ 10	$ 10	$ -	$ -
Cash collateral posted to counterparties (a)	21	21	-	-
Total assets	$ 31	$ 31	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 81	$ -	$ 81	$ -
Total price risk management liabilities	$ 81	$ -	$ 81	$ -

(a) Included in "Other noncurrent assets" on the Balance Sheets. Represents cash collateral posted to offset the exposure with counterparties related to certain interest rate swaps under master netting arrangements that are not offset.

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage interest rate risk, LG&E uses interest rate contracts such as forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. An income approach is used to measure the fair value of these contracts, utilizing readily observable inputs, such as forward interest rates (e.g., LIBOR and government security rates), as well as inputs that may not be observable, such as credit valuation adjustments. In certain cases, market information cannot practicably be obtained to value credit risk and therefore internal models are relied upon.

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These models use projected probabilities of default and estimated recovery rates based on historical observances. When the credit valuation adjustment is significant to the overall valuation, the contracts are classified as Level 3.

Financial Instruments Not Recorded at Fair Value

The carrying amounts of long-term debt on the Balance Sheets and their estimated fair values are set forth below. The fair values were estimated using an income approach by discounting future cash flows at estimated current cost of funding rates, which incorporate LG&E's credit risk. Long-term debt is classified as Level 2. The effect of third-party credit enhancements is not included in the fair value measurement.

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,642	$ 1,704	$ 1,345	$ 1,455

The carrying value of short-term debt, when outstanding, approximates fair value due to the variable interest rates associated with the short-term debt and is classified as Level 2.

13. Derivative Instruments and Hedging Activities

Risk Management Objectives

PPL has a risk management policy approved by the Board of Directors to manage market risk associated with commodities and interest rates on debt issuances (including price, liquidity and volumetric risk), and credit risk (including non-performance risk and payment default risk). The Risk Management Committee, comprised of senior management and chaired by the Chief Risk Officer, oversees the risk management function. Key risk control activities designed to ensure compliance with the risk policy and detailed programs include, but are not limited to, credit review and approval, validation of transactions, verification of risk and transaction limits and the coordination and reporting of the Enterprise Risk Management (ERM) program.

Market Risk

Market risk includes the potential loss that may be incurred as a result of price changes associated with a particular financial or commodity instrument as well as market liquidity and volumetric risks. Forward contracts and swaps are utilized as part of risk management strategies to minimize unanticipated fluctuations in earnings caused by changes in commodity prices and interest rates. Many of the contracts meet the definition of a derivative. All derivatives are recognized on the Balance Sheets at their fair value, unless NPNS is elected.

The following summarizes the market risks that affect LG&E. These risks are significantly mitigated due to recovery mechanisms in place.

Interest rate risk

- LG&E is exposed to interest rate risk associated with forecasted fixed-rate and existing floating-rate debt issuances. LG&E utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on floating-rate debt, and utilizes forward starting interest rate swaps to hedge changes in benchmark interest rates, when appropriate, in connection with future debt issuances.

- LG&E is exposed to interest rate risk associated with debt securities and derivatives held by defined benefit plans.

Commodity price risk

- LG&E's rates include certain mechanisms for fuel, natural gas supply and fuel-related expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses.

Equity securities price risk

- LG&E is exposed to equity securities price risk associated with defined benefit plans. This risk is significantly mitigated due to recovery mechanisms in place.

Credit Risk

Credit risk is the potential loss that may be incurred due to a counterparty's non-performance.

In the event a supplier of LG&E defaults on its obligation, LG&E would be required to seek replacement power or replacement fuel in the market. In general, subject to regulatory review or other processes, appropriate incremental costs incurred by LG&E would be recoverable from customers through applicable rate mechanisms, thus mitigating its financial risk.

LG&E has credit policies in place to manage credit risk, including the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements or provisions. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. LG&E may request additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade, their tangible net worth falls below specified percentages or their exposures exceed an established credit limit.

Master Netting Arrangements

Net derivative positions on the Balance Sheets are not offset against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

LG&E had no obligation to return cash collateral under master netting arrangements at December 31, 2015 and

2014.

LG&E posted $9 million and $21 million of cash collateral under master netting arrangements at December 31, 2015 and 2014.

See "Offsetting Derivative Instruments" below for a summary of derivative positions presented in the Balance Sheets where a right of setoff exists under these arrangements.

Interest Rate Risk

LG&E issues debt to finance its operations, which exposes it to interest rate risk. Various financial derivative instruments are utilized to adjust the mix of fixed and floating interest rates in its debt portfolio, adjust the duration of the debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under LG&E's risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of the debt portfolio due to changes in benchmark interest rates.

Cash Flow Hedges

Periodically, LG&E enters into forward-starting interest rate swaps with PPL that have terms identical to forward-starting swaps entered into by PPL with third parties. It is probable that realized gains and losses on all of these swaps will be recoverable through regulated rates; as such, any gains and losses on these derivatives are included in regulatory assets or liabilities and will be recognized in "Interest Expense" on the Statements of Income over the life of the underlying debt at the time the underlying hedged interest expense is recorded. In September 2015, LG&E issued first mortgage bonds totaling $550 million and all outstanding forward-starting interest rate swaps were terminated. Net cash settlements of $44 million were paid on the swaps that were terminated. The settlements are included in "Regulatory assets" (noncurrent) on the Balance Sheet and "Cash Flows from Operating Activities" on the Statements of Cash Flows.

Economic Activity

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statement of Income at the time the underlying hedged interest expense is recorded. At December 31, 2015, LG&E held contracts with a notional amount of $179 million that range in maturity through 2033.

Accounting and Reporting

All derivative instruments are recorded at fair value on the Balance Sheets as an asset or liability unless NPNS is elected. Changes in the fair value of derivatives not designated as NPNS are recognized currently in earnings unless specific hedge accounting criteria are met and designated as such, except for the changes in fair values of

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LG&E's interest rate swaps that are recognized as regulatory assets or regulatory liabilities. See Note 4 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2015 and 2014.

See Note 1 for additional information on accounting policies related to derivative instruments.

The following table presents the fair value and the location on the Balance Sheets of derivative instruments designated as cash flow hedges.

	December 31, 2015		December 31, 2014	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Current:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	$ -	$ -	$ -	$ 33

(a) Represents the location on the Balance Sheets.

The following table presents the pre-tax effect of derivative instruments designated as cash flow hedges that are recognized in regulatory assets and liabilities.

Derivative Instruments	**Location of Gain (Loss)**	**2015**	**2014**
Interest rate swaps	Regulatory asset - noncurrent	$ (11)	$ (33)
	Regulatory liabilities - noncurrent	-	-

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The following table presents the fair value and the location on the Balance Sheets of derivatives not designated as hedging instruments.

	December 31, 2015		December 31, 2014	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Current:				
Other Current Assets/Liabilities (a):				
Interest rate swaps	$ -	$ 5	$ -	$ 5
Total current	-	5	-	5
Noncurrent:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	-	42	-	43
Total noncurrent	-	42	-	43
Total derivatives	$ -	$ 47	$ -	$ 48

(a) Represents the location on the Balance Sheets.

The following tables present the pre-tax effect of derivatives not designated as cash flow hedges that are recognized in income or regulatory assets.

Derivative Instruments	Location of Gain (Loss)	2015	2014
Interest rate swaps	Interest Expense	$ (8)	$ (8)

Derivative Instruments	Location of Gain (Loss)	2015	2014
Interest rate swaps	Regulatory assets - noncurrent	$ 1	$ (12)

Offsetting Derivative Instruments

LG&E enters into agreements pursuant to which it purchases or sells certain energy and other products. Under the agreements, upon termination of the agreement as a result of a default or other termination event, the non-defaulting party typically would have a right to set off amounts owed under the agreement against any other obligations arising between the two parties (whether under the agreement or not), whether matured or contingent and irrespective of the currency, place of payment or place of booking of the obligation.

LG&E has elected not to offset derivative assets and liabilities and not to offset net derivative positions against

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the right to reclaim cash collateral pledged (an asset) or the obligation to return cash collateral received (a liability) under derivatives agreements. The table below summarizes the derivative positions presented in the Balance Sheets where a right of setoff exists under these arrangements and related cash collateral received or pledged.

	Liabilities			
		Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Pledged	Net
December 31, 2015				
Treasury derivatives	$ 47	$ -	$ 9	$ 38
December 31, 2014				
Treasury derivatives	$ 81	$ -	$ 20	$ 61

Credit Risk-Related Contingent Features

Certain derivative contracts contain credit risk-related contingent features which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in LG&E’s credit ratings. Most of these features would require the transfer of additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these features also would allow the counterparty to require additional collateral upon each downgrade in credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade, and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent features require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization on derivative instruments in net liability positions.

Additionally, certain derivative contracts contain credit risk-related contingent features that require adequate assurance of performance be provided if the other party has reasonable concerns regarding LG&E’s performance obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" features.

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At December 31, 2015, derivative contracts in a net liability position that contain credit risk-related contingent features, collateral posted on those positions and the related effect of a decrease in credit ratings below investment grade are summarized as follows:

Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent features	$	28
Aggregate fair value of collateral posted on these derivative instruments		9
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)		19

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheet.

14. Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2015		December 31, 2014	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Coal contracts (a)	$ 124	$ 116	$ 124	$ 98
Land and transmission rights	7	1	7	1
Emission allowances (b)	1	-	1	-
OVEC power purchase agreement (c)	87	29	87	23
Total subject to amortization	$ 219	$ 146	$ 219	$ 122

(a) Gross carrying amount represents the fair value at the acquisition date of coal contracts with terms favorable to market recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to these contracts, which is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 4 for additional information.
(b) Emission allowances are expensed when consumed or sold; therefore, there is no accumulated amortization.
(c) Gross carrying amount represents the fair value at the acquisition date of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to this contract, which is being amortized over the same period as the intangible asset, eliminating any income statement impact. See Note 4 for additional information.

Current intangible assets are included in "Other current assets" on the Balance Sheets. Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.

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Amortization expense was as follows:

	2015	2014
Intangible assets with regulatory offset	$ 24	$ 23

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2016	2017	2018	2019	2020
Intangible assets with regulatory offset	$ 14	$ 6	$ 6	$ 6	$ 6

15. Asset Retirement Obligations

LG&E's AROs are primarily related to the final retirement of assets associated with generating units. LG&E also has AROs related to natural gas mains and wells. LG&E's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. LG&E's accretion and depreciation expense are recorded as a regulatory asset, such that there is no earnings impact.

The changes in the carrying amounts of AROs were as follows.

	2015	2014
ARO at beginning of period	$ 74	$ 74
Accretion expense	5	4
Obligations incurred	3	-
Changes in estimated cash flow or settlement date	98	1
Obligations settled	(5)	(5)
ARO at end of period	175	74

LG&E recorded increases of $89 million to the existing AROs during 2015 as a result of an engineering study that was performed, in connection with the final CCR rule, providing clarity on projected CCR closure costs and revisions in the timing and amounts of future expected cash flows. Further increases to AROs or changes to current capital plans or to operating costs may be required as estimates of future cash flows are refined based on closure developments, groundwater monitoring results and regulatory or legal proceedings. In 2014, AROs were revalued primarily due to updates in the estimated cash flows for ash ponds based on updated cost estimates.

As of December 31, 2015, LG&E had $25 million of the ARO balances classified as current liabilities. These

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

current liabilities are primarily related to CCR closure costs expected to be incurred in 2016. As of December 31, 2014, substantially all of the ARO balances are classified as noncurrent liabilities.

See Note 10 for information on the final CCR rule and Note 6 for information on the rate recovery applications with the KPSC.

16. New Accounting Guidance Pending Adoption

Accounting for Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance that establishes a comprehensive new model for the recognition of revenue from contracts with customers. This model is based on the core principle that revenue should be recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

For public business entities, this guidance can be applied using either a full retrospective or modified retrospective transition method, beginning in annual reporting periods after December 15, 2017 and interim periods within those years. Public business entities may early adopt this guidance in annual reporting periods beginning after December 15, 2016. LG&E expects to adopt this guidance effective January 1, 2018.

LG&E is currently assessing the impact of adopting this guidance, as well as the transition method it will use.

17. Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information

	December 31, 2015	December 31, 2014
Cash paid (received) during the period for:		
Income taxes	$ (81)	$ 65
Interest on borrowed money	40	38
Other cash paid for interest	8	8

18. Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $8 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense $4 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $8 million applicable to Common Utility Plant apportioned to Electric Operations.

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NOTES TO FINANCIAL STATEMENTS (Continued)

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $3 million applicable to Common Utility Plant apportioned to Gas Operations.

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(l)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The annual report to shareholders or members and the statistical supplements covering the most recent two (2) years from the application filing date.

Response:

There are no annual reports to LG&E's shareholders during the period referenced. LG&E does not publish a statistical supplement.

Federal securities rules generally require the delivery of annual reports to public shareholders when requesting their vote via certain proxy solicitations. During the period in question, the common stock of LG&E has been wholly-owned by LG&E and KU Energy LLC, which is a wholly-owned subsidiary of PPL Corporation.

Copies of the audited annual financial statements and other financial information of LG&E relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 16(7)(p) [Tab No. 46].

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(m)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The current chart of accounts if more detailed than the Uniform System of Accounts chart prescribed by the commission.

Response:

See attached.

Account Number	Account Description
101101	PROPERTY UNDER CAPITAL LEASES
101102	PLANT IN SERVICE - ELECTRIC FRANCHISES AND CONSENTS
101103	PLANT IN SERVICE - MISC. INTANGIBLE PLANT
101104	PLANT IN SERVICE - ELECTRIC LAND
101105	PLANT IN SERVICE - ELECTRIC STRUCTURES
101106	PLANT IN SERVICE - ELECTRIC EQUIPMENT
101107	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
101108	PLANT IN SERVICE - ELECTRIC HYDRO EQUIPMENT
101109	PLANT IN SERVICE - ELECTRIC DISTRIBUTION EQUIPMENT
101110	PLANT IN SERVICE - LEASED PROPERTY
101111	PLANT IN SERVICE - ELECTRIC GENERAL EQUIPMENT
101112	PLANT IN SERVICE - ELECTRIC COMMUNICATION EQUIPMENT
101113	PLANT IN SERVICE - ELECTRIC LAND RIGHTS
101125	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
101126	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-CCR
101202	PLANT IN SERVICE - GAS FRANCHISES AND CONSENTS
101204	PLANT IN SERVICE - GAS LAND
101205	PLANT IN SERVICE - GAS STRUCTURES
101206	PLANT IN SERVICE - GAS UNDERGROUND AND TRANSMISSION EQUIPMENT
101207	PLANT IN SERVICE - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
101208	PLANT IN SERVICE - GAS TRANSPORTATION EQUIPMENT
101209	PLANT IN SERVICE - GAS DISTRIBUTION EQUIPMENT
101211	PLANT IN SERVICE - GAS GENERAL EQUIPMENT
101213	PLANT IN SERVICE - GAS LAND RIGHTS
101225	PLANT IN SERVICE - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
101301	PLANT IN SERVICE - COMMON ORGANIZATION
101302	PLANT IN SERVICE - COMMON FRANCHISES AND CONSENTS
101303	PLANT IN SERVICE - COMMON MISC. INTANGIBLE PLANT
101304	PLANT IN SERVICE - COMMON LAND
101305	PLANT IN SERVICE - COMMON STRUCTURES
101311	PLANT IN SERVICE - COMMON GENERAL EQUIPMENT
101312	PLANT IN SERVICE - COMMON COMMUNICATION EQUIPMENT
101313	PLANT IN SERVICE - COMMON LAND RIGHTS
101315	PLANT IN SERVICE - COMMON GENERAL EQUIPMENT
101325	PLANT IN SERVICE - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING
102001	ELECTRIC PLANT-PURCHASED OR SOLD
105001	PLT HELD FOR FUT USE
105002	PLANT HELD FOR FUTURE USE - LAND RIGHTS
106103	COMPL CONST NOT CL - MISC. INTANGIBLE PLANT
106104	COMPL CONST NOT CL - ELECTRIC LAND
106105	COMPL CONST NOT CL - ELECTRIC STRUCTURES
106106	COMPL CONST NOT CL - ELECTRIC EQUIPMENT
106108	COMPL CONST NOT CL - ELECTRIC HYDRO EQUIPMENT
106109	COMPL CONST NOT CL - ELECTRIC DISTRIBUTION EQUIPMENT
106111	COMPL CONST NOT CL - ELECTRIC GENERAL EQUIPMENT
106112	COMPL CONST NOT CL - ELECTRIC COMMUNICATION EQUIPMENT
106113	COMPL CONST NON CL-ELECTRIC LAND RIGHTS
106205	COMPL CONST NOT CL - GAS STRUCTURES
106206	COMPL CONST NOT CL - GAS UGD AND TRANSMISSION EQUIP
106208	COMPL CONST NOT CL - GAS TRANSPORTATION EQUIPMENT
106209	COMPL CONST NOT CL - GAS DISTRIBUTION EQUIPMENT
106211	COMPL CONST NOT CL - GAS GENERAL EQUIPMENT
106213	COMPL CONST NON CL-GAS LAND RIGHTS
106303	COMPL CONST NOT CL - COMMON MISC. INTANGIBLE PLANT
106305	COMPL CONST NOT CL - COMMON STRUCTURES
106311	COMPL CONST NOT CL - COMMON GENERAL EQUIPMENT
106312	COMPL CONST NOT CL - COMMON COMMUNICATION EQUIPMENT
106313	COMPL CONST NON CL-COMMON LAND RIGHTS
106315	COMPL CONST NOT CL - COMMON GENERAL EQUIPMENT
107001	CONSTR WORK IN PROG
108104	ACCUM. DEPR. - ELECTRIC LAND RIGHTS
108105	ACCUM. DEPR. - ELECTRIC STRUCTURES
108106	ACCUM. DEPR. - ELECTRIC EQUIPMENT
108107	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
108108	ACCUM. DEPR. - ELECTRIC HYDRO EQUIPMENT
108109	ACCUM. DEPR. - ELECTRIC DISTRIBUTION EQUIPMENT
108110	ACCUM. DEPR. - LEASED PROPERTY
108111	ACCUM. DEPR. - ELECTRIC GENERAL EQUIPMENT
108112	ACCUM. DEPR. - ELECTRIC COMMUNICATION EQUIP.
108113	ACCUM. DEPR. - ELECTRIC TRANSPORTATION EQUIP.
108114	ACCUM. DEPR. - COR - ELECTRIC LAND RIGHTS
108115	ACCUM. DEPR. - COR - ELECTRIC STRUCTURES
108116	ACCUM. DEPR. - COR - ELECTRIC EQUIPMENT
108118	ACCUM. DEPR. - COR - ELECTRIC HYDRO EQUIPMENT
108119	ACCUM. DEPR. - COR - ELECTRIC DISTRIBUTION
108120	ACCUM. DEPR. - COR - ELECTRIC GENERAL PROPERTY
108121	ACCUM. DEPR. - COR - ELECTRIC COMMUNICATION EQUIP.
108122	ACCUM. DEPR. - COR - LEASED PROPERTY
108125	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
108126	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-CCR
108204	ACCUM. DEPR. - GAS LAND RIGHTS
108205	ACCUM. DEPR. - GAS STRUCTURES
108206	ACCUM. DEPR. - GAS UNDERGROUND & TRANSMISSION EQUIPMENT
108207	ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
108209	ACCUM. DEPR. - GAS DISTRIBUTION EQUIPMENT

Account Number	Account Description
108211	ACCUM. DEPR. - GAS GENERAL EQUIP.
108213	ACCUM. DEPR. - GAS TRANSPORTATION EQUIP.
108215	ACCUM. DEPR. - COR - GAS STRUCTURES
108216	ACCUM. DEPR. - COR - GAS UNDERGROUND & TRANSMISSION EQUIP.
108219	ACCUM. DEPR. - COR - GAS DISTRIBUTION EQUIPMENT
108220	ACCUM. DEPR. - COR - GAS GENERAL EQUIP.
108225	ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
108304	ACCUM. DEPR. - COMMON LAND RIGHTS
108305	ACCUM. DEPR. - COMMON STRUCTURES
108311	ACCUM. DEPR. - COMMON GENERAL EQUIPMENT
108312	ACCUM. DEPR. - COMMON COMMUNICATION EQUIPMENT
108313	ACCUM. DEPR. - COMMON TRANSPORTATION EQUIP.
108314	ACCUM. DEPR. - COMMON GENERAL EQUIPMENT - NONUTILITY
108315	ACCUM. DEPR. - COR - COMMON STRUCTURES
108321	ACCUM. DEPR. - COR - COMMON EQUIPMENT
108325	ACCUM. DEPR. - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING
108414	ACCUM. DEPR. - SALVAGE - ELECTRIC LAND RIGHTS
108415	ACCUM. DEPR. - SALVAGE - ELECTRIC STRUCTURES
108416	ACCUM. DEPR. - SALVAGE - ELECTRIC EQUIPMENT
108418	ACCUM. DEPR. - SALVAGE - ELECTRIC HYDRO EQUIPMENT
108419	ACCUM. DEPR. - SALVAGE - ELECTRIC DISTRIBUTION
108420	ACCUM. DEPR. - SALVAGE - ELECTRIC GENERAL PROPERTY
108421	ACCUM. DEPR. - SALVAGE - ELECTRIC COMMUNICATION EQUIP.
108515	ACCUM. DEPR. - SALVAGE - GAS STRUCTURES
108516	ACCUM. DEPR. - SALVAGE - GAS UNDERGROUND & TRANSMISSION EQUIP.
108519	ACCUM. DEPR. - SALVAGE - GAS DISTRIBUTION EQUIPMENT
108520	ACCUM. DEPR. - SALVAGE - GAS GENERAL EQUIP.
108621	ACCUM. DEPR. - SALVAGE - COMMON EQUIPMENT
108622	ACCUM. DEPR. - SALVAGE - COMMON COMMUNICATION EQUIPMENT
108799	RWIP-ARO LEGAL
108899	RWIP-ARO-ECR CLEARING
108901	RETIREMENT - RWIP
111102	AMORTIZATION EXPENSE - ELECTRIC FRANCHISES AND CONSENTS
111103	AMORTIZATION EXPENSE - ELECTRIC INTANGIBLES
111202	AMORTIZATION EXPENSE - GAS FRANCHISES AND CONSENTS
111302	AMORTIZATION EXPENSE - COMMON FRANCHISES AND CONSENTS
111303	AMORTIZATION EXPENSE - COMMON INTANGIBLES
117001	GAS STORED-NONCUR
117101	GAS STORED - NONCURRENT RECOVERABLE BASE GAS
121001	NONUTIL PROP IN SERV
121007	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
121103	MACHINERY & EQUIPMENT
121105	LEASEHOLD IMPROVEMENTS
121106	COMPUTER EQUIPMENT
121107	FURNITURE & FIXTURES
121108	COMPUTER SOFTWARE
122001	ACCUM DEPR/DEPL
122002	ACCUM AMORT-NONUTIL
122007	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIRMENT COST-EQUIPMENT
122203	MACHINERY & EQUIPMENT - ACCUM DEPRECIATION
122205	LEASEHOLD IMPROVEMENTS - ACCUM DEPRECIATION
122206	COMPUTER EQUIPMENT - ACCUM DEPRECIATION
122207	FURNITURE & FIXTURES - ACCUM DEPRECIATION
122208	COMPUTER SOFTWARE - ACCUM DEPRECIATION
123102	INVESTMENT IN LGE PA ADJS
123103	INVEST IN LGE
123104	INVEST IN LGE CAPITAL
123105	INVESTMENT IN KU
123108	INVEST IN LEM
123109	INVEST IN SERVCO
123116	INVEST IN WKE
123118	INVEST IN FCD LLC
123123	INVESTMENT IN OVEC
123124	INVESTMENT IN DHA
123125	INVEST IN LGE CAPITAL PA ADJS
123126	INVEST IN HOME SERVICES PA ADJS
123127	INVEST IN SERVCO PA ADJS
123128	INVEST IN WKE PA ADJS
123129	INVEST IN FCD LLC PA ADJS
123130	INVEST IN LEM PA ADJS
123133	INVEST IN DOWNTOWN COMMERICAL LOAD FUND
123134	INVESTMENT IN SUBS - CURRENT-YEAR EQUITY IN EARNINGS
123175	INVESTMENT IN KU PA ADJS
128023	PREPAID PENSION
128026	COLLATERAL DEPOSIT - IR SWAPS
128027	RESTRICTED CASH - NON-CURRENT
128028	PREPAID POSTRETIREMENT
131024	CASH- BNY MELLON BANK
131033	US BANK - LGE - LOUISVILLE
131050	SUNDRY CASH COLLECT
131069	CASH CLEARING - CCS
131080	CASH LOCKBOX - BANK OF AMERICA - LOUISVILLE
131090	CASH-BOA A/P - CLEARING
131091	CASH-BOA PAYROLL
131092	CASH-BOA FUNDING
131204	BANK OF AMERICA - REGULUS - KU

Account Number	Account Description
131227	US BANK - MASTER ROLL UP ACCOUNT
131235	BANK OF AMERICA (BANK DRAFTS) - KU LOUISVILLE
131236	US BANK - BARLOW 134-1
131237	US BANK - EARLINGTON 141-5
131238	US BANK - EDDYVILLE 150-1
131239	US BANK - GREENVILLE 161-2
131240	US BANK - MORGANFIELD 171-1
131241	US BANK - CAMPBELLSVILLE 222-2
131242	US BANK - MOREHEAD 342-2
131243	US BANK - PARIS 351-1
131244	US BANK - LONDON 421-2
131245	US BANK - MIDDLESBORO 431-1
131246	US BANK - HARLAN 441-2
131247	US BANK - SOMERSET 451-1
131248	US BANK - NORTON 761-2
131249	US BANK - PENNINGTON GAP 773-1
131250	US BANK - DANVILLE 211-2
131251	US BANK - RICHMOND 231-2
131252	US BANK - E-TOWN 241-1
131253	US BANK - SHELBYVILLE 251-2
131254	US BANK - LEXINGTON 311-9
131255	US BANK - GEORGETOWN 321-3
131256	US BANK - VERSAILLES 331-3
131257	US BANK - MT. STERLING 341-2
131258	US BANK - MAYSVILLE 361-1
131259	US BANK - CARROLLTON 371-2
131260	US BANK - WINCHESTER 385-3
134007	RESTRICTED CASH - SHORT TERM
135001	WORKING FUNDS
136005	TEMP INV-OTHER
136015	TEMPORARY INVESTMENT ACCOUNTS AT BANK OF AMERICA
136016	TEMP INV-GOLDMAN SACHS-CASH UNRESTRICTED
136017	TEMP INV-BLACKROCK TEMP FUND #24 (TMPXX)
136018	TEMP INV-FIDELITY INVESTMENTS-CASH UNRESTRICTED
136019	TEMP INV-JPMORGAN-CASH UNRESTRICTED
136020	TEMP INV-UBS-CASH UNRESTRICTED
136021	TEMP INV-DREYFUS INSTITUTIONAL CASH ADV #99 (DADXX)
136022	TEMP INV-DEUTSCHE MONEY MARKET SERIES #2403 (ICAXX)
136023	TEMP INV-FED PRIME OBLIGATIONS FUND#851 (PCOXX)
136024	TEMP INV-GOLDMAN SACHS FIN SQUARE MMF #474 (FSMXX)
136025	TEMP INV-INVESCO LIQUID ASSETS PORTFOLIO#1913 (LAPXX)
136026	TEMP INV-WELLS FARGO HERITAGE MMF #WBC58 (WFJXX)
136027	TEMP INV-WESTERN ASSET INST CASH RES #193 (CARXX)
136028	TEMP INV-SUNTRUST
141004	NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
141005	RESERVE FOR NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
142001	CUST A/R-ACTIVE
142002	A/R - UNPOSTEC CASH
142003	WHOLESALE SALES A/R
142004	TRANSMISSION RECEIVABLE
142012	ACCTS REC - MISC CUSTOMERS - SUNDRY
142999	CUST A/R KU SUSP CIS- ACCTG USE ONLY
143001	A/R-OFFICERS/EMPL
143003	ACCTS REC - IMEA
143004	ACCTS REC - IMPA
143006	ACCTS REC - BILLED PROJECTS
143007	ACCTS REC - NON PROJECT UTIL ACCT USE ONLY
143011	INSURANCE CLAIMS
143012	ACCTS REC - MISCELLANEOUS
143017	ACCTS REC - DAMAGE CLAIMS (DTS)
143024	A/R MUTUAL AID
143027	INCOME TAX RECEIVABLE - FEDERAL
143028	INCOME TAX RECEIVABLE - STATE
143030	EMPLOYEE PAYROLL ADVANCES
143032	ACCTS REC - TAX REFUNDS
143036	SUSPENSE - PPL
143037	STATE INCOME TAX RECEIVABLE
143040	ACCTS REC - WKE UNWIND - DISPATCH, IT ADHOC, & CENTURY
143041	COBRA/LTD BENEFITS - RECEIVABLE
143052	ACCOUNTS RECEIVABLE - IMEA/IMPA OFFSET
143053	LIQUIDATED DAMAGES RECEIVABLE
144001	UNCOLL ACCT-CR-UTIL
144002	UNCOLL ACCT-DR-C/OFF
144003	UNCOLL ACCT-CR-RECOV
144004	UNCOLL ACCT-CR-OTHER
144006	UNCOLL ACCT-A/R MISC
144011	UNCOLL MISC A/R PROVISION
144014	UNCOLL A/R - WKE RESERVES
144015	UNCOLL A/R - LIQUIDATED DAMAGES
144016	UNCOLL A/R - CENTURY INTEREST
145011	N/R - MONEY POOL - LGE
145012	N/R - MONEY POOL - KU
145013	N/R - MONEY POOL - LCC
145015	N/R - MONEY POOL - LEM
145020	NOTES RECEIVABLE FROM LKE - CURRENT
145021	NOTES RECEIVABLE - PPL ENERGY FUNDING - CURRENT

Account Number	Account Description
145022	N/R - MONEY POOL - FCD
145023	N/R - MONEY POOL - WKE
145025	NOTES RECEIVABLE FROM LG&E AND KU ENERGY LLC NON-CURRENT
145100	N/R MONEY POOL - LG&E AND KU ENERGY LLC
146048	INTERCOMPANY DIVIDENDS RECEIVABLE FROM LG&E COMPANY
146049	INTERCOMPANY ADVANCE FROM LG&E
146050	INTERCOMPANY ADVANCE FROM KU
146053	INTERCOMPANY PENSION RECEIVABLE
146054	I/C RECEIVABLE - PPL ELECTRIC UTILITIES CORPORATION
146055	I/C INTEREST RECEIVABLE - PPL ENERGY FUNDING CURRENT
146056	INTERCOMPANY DIVIDENDS RECEIVABLE FROM KU COMPANY
146057	I/C RECEIVABLE - PPL SERVICES CORPORATION
146058	I/C RECEIVABLE - PPL CORPORATION
146061	INTERCOMPANY INCOME TAX RECEIVABLE - FEDERAL
146070	I/C RECEIVABLE - PPL TRANSLINK
146100	INTERCOMPANY
151010	FUEL STK-LEASED CARS
151020	COAL PURCHASES - TONS - $
151021	COAL - BTU ADJ - BTU
151022	COAL FINES - CONSIGNED INVENTORY
151023	IN-TRANSIT COAL - TONS - $
151024	COAL - CONSIGNED INVENTORY
151025	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - COAL PURCHASES - TONS - $
151026	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - COAL PURCHASES (STAT ONLY)
151030	FUEL OIL - GAL - $
151031	FUEL OIL - BTU
151032	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - FUEL OIL - GAL - $
151033	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - FUEL OIL (STAT ONLY)
151060	RAILCARS-OPER/MTCE
151061	GAS PIPELINE OPER/MTCE - MCF - $
151070	PETROL COKE-TEM STOR - TONS
151071	PETROL COKE-TEM STOR - BTU
151073	IN-TRANSIT COAL-MMBTU/IN-TRANSIT PET COKE <AUG 2009
151080	COAL BARGE SHUTTLING
154001	MATERIALS/SUPPLIES
154003	LIMESTONE
154004	COMMERCIAL LIME
154006	OTHER REAGENTS
154007	TC NON-JURISDICTIONAL CONTRA (IMEA/IMPA) - LIMESTONE
154008	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - M&S
154023	LIMESTONE IN-TRANSIT
158121	SO2 ALLOWANCE INVENTORY
158122	NOX OZONE SEASON ALLOWANCE INVENTORY
158124	SO2 ALLOWANCE INVENTORY-FUTURE VINTAGE (LT)
158125	NOX ANNUAL ALLOWANCE INVENTORY
158126	NOX OZONE SEASON ALLOWANCE INVENTORY - FUTURE VINTAGE (LT)
158127	NOX ANNUAL ALLOWANCE INVENTORY - FUTURE VINTAGE (LT)
163011	STORES EXPENSE - GENERATION
163012	WAREHOUSE EXPENSES - GENERATION
163013	FREIGHT - GENERATION
163014	ASSET RECOVERY - GENERATION
163015	SALES TAX - GENERATION
163016	PHYS INVENT ADJUSTMT - GENERATION
163017	INVOICE PRICE VARIANCES - GENERATION
163101	OTHER - GENERATION
163201	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - STORES
164101	GAS STORED-CURRENT
165001	PREPAID INSURANCE
165002	PREPAID TAXES
165006	PREPAID GAS FRANCH
165012	PREPAID LEASE
165013	PREPAID RIGHTS OF WAY
165018	PREPAID RISK MGMT AND WC
165025	PREPAID SALES & OTHER TAXES
165026	PREPAID ADP FUNDING
165100	PREPAID OTHER
165101	PREPAID IT CONTRACTS
165102	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - PREPAID INSURANCE
165201	PREPAID IT CONTRACTS-LT
165202	PREPAID POWELL LEASE-LT
165203	PREPAID RIGHTS OF WAY-LT
165204	PREPAID INSURANCE - LONG TERM
165900	PREPAID OTHER - INDIRECT
165950	PREPAID INSURANCE - INDIRECT
171001	INTEREST RECEIVABLE
172001	RENTS RECEIVABLE FOR POLE ATTACHMENTS
173001	ACCRUED UTIL REVENUE
173002	ACCRUED REVENUE - UNBILLED BEYOND THE METER
173005	ACCRUED WHOLESALE SALES REVENUE - UNBILLED
174001	MISC CURR/ACCR ASSET
181100	UAMORTIZED DEBT EXPENSE
181200	UNAMORTIZED DEBT EXPENSE REVOLVERS/LCS
181300	UNAMORTIZED DEBT EXPENSE BONDS
182305	REGULATORY ASSET - FAS 158 OPEB
182306	FUEL ADJUSTMENT CLAUSE
182307	ENVIRONMENTAL COST RECOVERY

Account Number	Account Description
182308	REG ASSET - GAS SUPPLY CLAUSE
182309	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (CURRENT)
182311	FERC JURISDICTIONAL PENSION EXPENSE
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION-15 YEAR
182314	OTHER REGULATORY ASSETS
182315	REGULATORY ASSET - FAS 158 PENSION
182317	OTHER REGULATORY ASSETS ARO - GENERATION
182318	OTHER REG ASSETS ARO - TRANSMISSION
182320	WINTER STORM - ELECTRIC
182321	MISO EXIT FEE
182322	RATE CASE EXPENSES - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182323	RATE CASE EXPENSES - GAS - PRE-PPL MERGER CURRENT PORTION
182325	OTHER REGULATORY ASSETS ARO - DISTRIBUTION
182326	OTHER REGULATORY ASSETS ARO - GAS
182327	OTHER REGULATORY ASSETS ARO - COMMON
182328	FASB 109 ADJ-FED
182329	FASB 109 GR-UP-FED
182330	FASB 109 ADJ-STATE
182331	FASB 109 GR-UP-STATE
182332	CMRG FUNDING (CARBON MGT RESEARCH GROUP)
182333	KCCS FUNDING (KY CONSORTIUM FOR CARBON STORAGE)
182334	WIND STORM REGULATORY ASSET
182335	RATE CASE EXPENSES - ELECTRIC
182336	RATE CASE EXPENSES - GAS
182337	EKPC FERC TRANSMISSION COSTS - KY PORTION
182339	MOUNTAIN STORM - ELECTRIC
182340	CLOSED 04/16 - REG ASSET - PERFORMANCE-BASED RATES
182342	WINTER STORM - GAS
182343	ASSET - SWAP TERMINATION - PRE-PPL MERGER CURRENT PORTION
182344	REG ASSET - LT - SWAP TERMINATION
182345	WINTER STORM - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182346	WINTER STORM - GAS - PRE-PPL MERGER CURRENT PORTION
182347	WIND STORM - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182348	CMRG FUNDING - PRE-PPL MERGER CURRENT PORTION
182349	KCCS FUNDING - PRE-PPL MERGER CURRENT PORTION
182352	REG ASSET - LT INTEREST RATE SWAP
182353	REG. ASSET - COAL CONTRACT - ST
182354	REG. ASSET - COAL CONTRACT
182356	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (NON-CURRENT)
182358	REG ASSET - UNAMORT DEBT EXP PAA
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC
182360	GENERAL MANAGEMENT AUDIT - GAS
182361	2011 SUMMER STORM - ELECTRIC
182363	DSM COST RECOVERY - UNDER-RECOVERY
182365	GAS LINE TRACKER- REG ASSET
182366	REG ASSET - MUNI GEN TRUE UP
182367	REG ASSET - MUNI MISO EXIT FEE
182368	VA FUEL COMPONENT - NON-JURISDICTIONAL CUSTOMERS (CURRENT)
182369	GREEN RIVER REGULATORY ASSET
182370	REGULATORY ASSET - OST
182371	REG ASSET - FORWARD STARTING SWAPS SEP-2015
182372	OTHER REGULATORY ASSETS ARO - GENERATION - CCR
182373	REG. ASSET - OPEN ARO PONDS - KY
182374	REG. ASSET - OPEN ARO PONDS - VA
182375	REG. ASSET - OPEN ARO PONDS - FERC REMAINING MUNI
182376	REG. ASSET - OPEN ARO PONDS - FERC DEPARTING MUNI
182377	REG. ASSET - CLOSED ARO PONDS - KY
182378	REG. ASSET - CLOSED ARO PONDS - VA
182379	REG. ASSET - CLOSED ARO PONDS - FERC REMAINING MUNI
182380	REG. ASSET - CLOSED ARO PONDS - FERC DEPARTING MUNI
183201	OTH PREL SUR/INV-GAS
183301	PRELIM SURV/INV-ELEC
183302	PRELIMINARY SURV/INV ELEC - LT
184002	VACATION PAY
184011	HOLIDAY PAY
184021	SICK PAY
184031	OTHER OFF-DUTY PAY
184040	TEAM INCENTIVE AWARD - BURDEN CLEARING
184075	WORKERS COMP - BURDEN CLEARING
184076	ADMINISTRATIVE AND GENERAL - BURDEN CLEARING
184093	LONG TERM DISABILITY - BURDEN CLEARING
184096	PENSION SERVICE COST - BURDEN CLEARING
184097	FASB 106 (OPEB) SERVICE COST - BURDEN CLEARING
184098	FASB 112 - BURDEN CLEARING
184100	WALL STREET SUSPENSE ACCOUNT
184101	GROUP LIFE INSURANCE - BURDEN CLEARING
184104	DENTAL INSURANCE - BURDEN CLEARING
184105	MEDICAL INSURANCE - BURDEN CLEARING
184108	401K - BURDEN CLEARING
184109	RETIREMENT INCOME - BURDEN CLEARING
184119	PENSION NON SERVICE COST - BURDEN CLEARING
184120	FASB 106 POST RETIREMENT NON SERVICE COST - BURDEN CLEARING
184121	OTHER BENEFITS - BURDEN CLEARING
184125	UNEMPLOYMENT TAXES - FED AND STATE
184130	LKS ALLOCATION CLEARING ACCOUNT
184135	ORACLE PROJECT BURDEN CLEARING ACCOUNT

Account Number	Account Description
184136	LKS ALLOC. CLEARING ACCOUNT FOR ALLOCATED CAPITAL
184140	MEDICAL PAYMENT HOLDING ACCT - (SERVCO ONLY)
184150	SYSTEM ALLOC-CO 1
184301	GASOLINE-TRANSP
184304	VEHICLE REPR-TRANSP
184307	ADMIN/OTH EXP-TRANSP
184308	VALUE-ADD SVCSTR
184309	DIESEL FUEL-TRANSP
184312	RENT/STORAGE-TRANSP
184313	TELECOM VEHICLE RADIO / COMPUTER EXPENSES
184314	LICENSE/TAX-TRANSP
184315	DEPRECIATION-TRANSP
184319	FUEL ADMINISTRATION VEHICLES
184320	TRANSPORTATION EXPENSE ALLOCATION - CLEARING
184450	CL ACC TO OTH DEF CR
184503	OPERATIONS - SIMPSONVILLE
184504	OPERATION-SSC
184505	MAINTENANCE-SSC
184506	MAINTENANCE - SIMPSONVILLE
184507	OPERATIONS - KU GENERAL OFFICE
184508	MAINTENANCE - KU GENERAL OFFICE
184509	OPERATIONS - LGE CENTER
184513	OTHER EXPENSES - LGE CENTER
184514	OPERATION-ESC
184515	MAINTENANCE-ESC
184516	OPERATION-BOC
184517	MAINTENANCE-BOC
184518	OPERATION-AUBURNDALE
184519	MAINT-AUBURNDALE
184521	OPERATIONS - MORGANFIELD
184522	MAINTENANCE - MORGANFIELD
184523	OPERATIONS - DIX DAM
184524	MAINTENANCE - DIX DAM
184525	OPERATIONS - EARLINGTON
184526	MAINTENANCE - EARLINGTON
184530	CLOSED 09/16 - MISC FACILITIES ALLOCATION-OFFSET
184531	OPERATIONS - RIVERPORT
184532	MAINTENANCE - RIVERPORT
184533	OPERATIONS - PINEVILLE
184534	MAINTENANCE - PINEVILLE
184599	MISC FACILITIES ALLOCATION-OFFSET
184600	ENGINEERING OVERHEADS - GENERATION
184602	ENGINEERING OVERHEADS - DISTRIBUTION
184603	ENGINEERING OVERHEADS - RETAIL GAS
184605	ENGINEERING OVERHEADS - TRANSMISSION
184612	ENGINEERING OVERHEADS - DISTRIBUTION
184650	CUSTOMER ADVANCES - CLEARING
184701	EMPLOYEE ADVANCES - CLEARING
184702	IEXPENSE CREDIT CARD CLEARING
186001	MISC DEFERRED DEBITS
186004	FINANCING EXPENSE
186035	KEY MAN LIFE INSURANCE
186049	PRELIMINARY CELL SITE COSTS
186074	CANE RUN 7 LTPC ASSET
186505	GOODWILL
186548	OTHER INTANGIBLE ASSETS - SHORT TERM
186549	OTHER INTANGIBLE ASSETS
186553	OTH INTANG ASSETS - OVEC PPA ENERGY CONTRACT
186556	OTH INTANG ASSETS - SO2 ALLOWANCES - CURRENT
186557	OTH INTANG ASSETS - NOX OZONE ALLOWANCES - CURRENT
186558	OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - CURRENT
186559	OTH INTANG ASSETS - SO2 ALLOWANCES - FUTURE
186560	OTH INTANG ASSETS - NOX OZONE ALLOWANCES - FUTURE
186561	OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - FUTURE
186576	CARROLLTON SALE/LEASEBACK
188001	RESRCH/DEV/DEMO EXP
188901	RESRCH/DEV/DEMO EXP - INDIRECT
189100	UAMORTIZED LOSS ON REACQUIRED DEBT
190007	FASB 109 ADJ-FED
190008	FASB 109 GRS-UP-FED
190009	FASB 109 ADJ-STATE
190010	FASB 109 GRS-UP-ST
190315	CLOSED 03/16 - DTA FEDERAL - CURRENT
190316	CLOSED 03/16 - NETTING - DEFERRED TAX ASSETS - CURRENT - FEDERAL
190317	CLOSED 03/16 - NETTING - DEFERRED TAX LIABILITIES - CURRENT - FEDERAL
190414	DTA ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
190415	DTA FEDERAL - NON-CURRENT
190416	DTA ON FIN 48 - UTP - FEDERAL
190515	CLOSED 03/16 - DTA STATE - CURRENT
190516	CLOSED 03/16 - NETTING - DEFERRED TAX ASSETS - CURRENT - STATE
190517	CLOSED 03/16 - NETTING - DEFERRED TAX LIABILITIES - CURRENT - STATE
190614	DTA ON PROVISIONS FOR PENSIONS - OCI - ST (NON-CURRENT)
190615	DTA STATE - NON-CURRENT
190616	DTA ON FIN 48 - UTP - STATE
201001	COMMON STOCK-AUTH SH
201002	COMMON STOCK-W/O PAR

Account Number	Account Description
211001	CONTRIBUTED CAPITAL - MISC.
214010	CAP STOCK EXP-COMMON
216001	UNAPP RETAINED EARN
216101	UNAPP UNDST SUB EARN
219010	ACCUM OCI - EQUITY INVEST EEI
219011	ACCUM OCI OF SUBS - PTAX
219013	OCI - FAS 158 INCREASE FUNDED STATUS - GROSS
219014	AOCI - FAS 158 POST-ACQUISITION
219110	DEFERRED TAX - OCI - EQUITY INVEST EEI
219111	ACCUM OCI OF SUBS - TAX
219113	OCI - FAS 158 INCREASE FUNDED STATUS - TAX
219114	AOCI TAX - FAS 158 POST-ACQUISITION
221100	LONG TERM DEBT
221899	CURRENT PORTION OF LONG TERM DEBT
223014	LT NOTES PAYABLE TO SERVCO
223100	LT NOTES PAYABLE TO PPL CAPITAL FUNDING PRINCIPAL
223101	LT - NOTES PAYABLE TO CEP RESERVES
224100	PAA PCB FMV ADJUSTMENT
226100	DEBT DISCOUNT BONDS
228201	WORKERS COMPENSATION
228202	WORKERS COMPENSATION - SHORT-TERM
228301	FASB106-POST RET BEN
228304	PENSION PAYABLE
228305	POST EMPLOYMENT BENEFIT PAYABLE
228306	PENSION PAYABLE SERP
228307	FASB 106 - MEDICARE SUBSIDY
228308	PENSION PAYABLE - SERP - NON-MERCER
228318	PENSION PAYABLE - SERP - NON-MERCER - CURRENT
228325	FASB 112 - POST EMPLOY MEDICARE SUBSIDY
230011	ASSET RETIREMENT OBLIGATIONS - STEAM - CCR
230012	ASSET RETIREMENT OBLIGATIONS - STEAM
230013	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION
230015	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION
230016	ASSET RETIREMENT OBLIGATIONS - GAS
230017	ASSET RETIREMENT OBLIGATIONS - COMMON
230021	ASSET RETIREMENT OBLIGATIONS - STEAM - CCR - ST
230022	ASSET RETIREMENT OBLIGATIONS - STEAM - ST
230023	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION - ST
230025	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION - ST
230026	ASSET RETIREMENT OBLIGATIONS - GAS - ST
230027	ASSET RETIREMENT OBLIGATIONS - COMMON - ST
230799	RWIP-ARO-ECR
231005	COMMERCIAL PAPER PAYABLE
231006	DISCOUNT ON COMMERCIAL PAPER
231008	ST-NP KU REVOLVING CREDIT $400M 12/14
231019	ST-NP LGE REVOLVING CREDIT $400M 12/14
231100	REVOLVING CREDIT FACILITIES
232001	ACCTS PAYABLE-REG
232002	SALS/WAGES ACCRUED
232008	SUNDRY BILLING REFUNDS
232009	PURCHASING ACCRUAL
232010	WHOLESALE PURCHASES A/P
232011	TRANSMISSION PAYABLE
232014	RECEIVING/INSPECTION ACCRUAL
232015	AP FUEL
232022	ACCRUED AUDIT FEES
232023	ACCRUED TAXABLE OFFICER BENEFITS
232024	CREDIT CASH BALANCE
232027	CREDIT CARD PAYMENTS
232028	AP FUEL - NATURAL GAS
232030	RETAINAGE FEES
232042	MISO AND PJM ANCILLARY SERVICES CHARGES A/P
232060	AP - GAS SUPPLY PURCHASES
232093	SUSPENSE - CCS
232095	SUSPENSE - SALES TAX BURDEN
232096	SUSPENSE - OTHER BURDENS
232097	SUSPENSE - INVENTORY
232098	SUSPENSE - MANUAL DISABLED
232099	SUSPENSE ACCOUNT
232100	ACCOUNTS PAYABLE-TRADE
232111	401K LIABILITY - EMPLOYER
232205	IBEW UNION DUES WITHHOLDING PAYABLE
232206	UNITED WAY WITHHOLDING PAYABLE
232211	TIA LIABILITY
232220	CREDIT UNION WITHHOLDING PAYABLE
232233	401K WITHHOLDING PAYABLE
232235	UNITED STEEL WORKERS UNION DUES
232243	LOUISVILLE PAC WITHHOLDING PAYABLE
232244	GARNISHEES WITHHOLDING PAYABLE
232246	DCAP WITHHOLDING PAYABLE
232248	HCRA WITHHOLDING PAYABLE
232249	UNIVERSAL LIFE INS WITHHOLDING PAYABLE
232252	HEALTH EQUITY HIGH DEDUCTIBLE WITHHOLDING PAYABLE
233011	ST - NOTES PAYABLE TO LKE PARENT
233013	ST - NOTES PAYABLE TO SERVCO
233030	N/P - MONEY POOL LG&E AND KU ENERGY LLC CURRENT

Account Number	Account Description
233100	N/P - MONEY POOL LG&E
233102	N/P - MONEY POOL KU
233103	N/P - MONEY POOL LEM
233104	N/P - MONEY POOL FCD
234012	I/C PAYABLE CEP RESERVES
234051	INTERCOMPANY PENSION PAYABLE
234052	I/C PAYABLE-PPL SERVICES CORPORATION
234055	I/C PAYABLE-PPL CORPORATION
234056	I/C PAYABLE-PPL CAPITAL FUNDING, INC.
234092	I/C PAYABLE TO PPL ENERGY FUNDING CORP
234100	A/P TO ASSOC CO
235001	CUSTOMER DEPOSITS
235002	CUSTOMER DEPOSITS OFF-SYS
235003	CUSTOMER DEPOSITS - TRANSMISSION
236007	FICA-OPR
236013	ST SALES/USE TAX-KY-OPR
236023	ST SALES/USE TAX-IN-OPR
236025	CORP INC TAX-FED EST-OPR
236026	CORP INC TAX-ST EST-OPR
236031	CORP INCOME-KY-OPR
236032	CORP INCOME-FED-OPR
236033	REAL ESTATE AND PERSONAL PROPERTY TAXES
236034	PROPERTY TAX ON RAILCARS USED FOR COAL
236035	OTHER TAXES ACCRUED-OPR
236036	REAL ESTATE AND PERSONAL PROPERTY TAXES - NON KY
236037	VIRGINIA USE TAX
236115	STATE UNEMPLOYMENT-OPR
236116	FEDERAL UNEMPLOYMENT-OPR
237100	ACCR INT LONG-TERM DEBT
237300	INT ACC-OTH LIAB
237301	INTEREST ACCRUED ON CUSTOMER DEPOSITS
237304	INTEREST ACCRUED ON TAX LIABILITIES
238200	DIV PAYABLE - PARENT FM LGE
238203	DIV PAYABLE - PARENT FM KU
238204	DIV PAYABLE - PPL FM LKE
241007	TAX COLL PAY-FICA
241018	STATE WITHHOLDING TAX PAYABLE
241036	LOCAL WITHHOLDING TAX PAYABLE
241037	T/C PAY-PERS INC-FED
241038	T/C PAY-ST SALES/USE
241039	T/C PAY-OCCUP/SCHOOL
241046	CONSUMER UTILITY TAX-VA
241049	FRANCHISE FEE PAYABLE-CHARGE UNCOLLECTED
241056	FRANCHISE FEE COLLECTED ON BAD DEBTS
241061	T/C PAY - ST SALES/USE OVER COLLECTIONS
241062	T/C PAY - SCHOOL TAX OVER COLLECTIONS
242001	MISC LIABILITY
242002	MISC LIAB-VESTED VAC
242005	UNEARNED REVENUE - CURRENT
242014	ESCHEATED DEPOSITS
242015	FRANCHISE FEE PAYABLE-FRANCHISE LOCATIONS
242017	HOME ENERGY ASSISTANCE
242018	GREEN POWER REC LIABILITY
242019	GREEN POWER MKT LIABILITY
242021	FASB 106-POST RET BEN - CURRENT
242022	ACCRUED SHORT TERM INCENTIVE
242023	PENSION PAYABLE SERP CURRENT
242026	PENSION PAYABLE - CURRENT
242027	AR CREDITS
242028	SERVICE DEPOSIT REFUND PAYABLE
242030	WINTERCARE ENERGY FUND
242031	NO-NOTICE GAS PAYABLE
242034	MCI UNEARNED REVENUE
242038	COBRA/LTD BENEFITS - PAYABLE
242039	SUSPENSE - CASH
242080	LEASEHOLD INCENTIVE LG&E CENTER LEASE 07012012 - CURRENT
242101	RETIREMENT INCOME LIABILITY
242102	IBNP MEDICAL AND DENTAL RESERVE
244511	LT DERIVATIVE LIAB FAS 133 JPM
244512	LT DERIV LIAB FAS 133-NON HEDGING MS1
244513	LT DERIV LIAB FAS 133-NON HEDGING MS2
244514	LT DERIV LIAB FAS 133-NON HEDGING BOA
244515	ST DERIV LIAB FAS 133-NON HEDGING MS1
244516	ST DERIV LIAB FAS 133-NON HEDGING MS2
244517	ST DERIV LIAB FAS 133-NON HEDGING BOA
244519	ST DERIV LIAB FAS 133 JPM
252011	LINE EXTENSIONS
252013	CUSTOMER ADVANCES - CONSTRUCTION - LONG TERM
252014	CLOSED 08/16 - CUST OUTDOOR LIGHTING DEPOSITS
252015	MOBILE HOME LINE
252017	CUSTOMER ADVANCES - SHORT TERM
252018	CLOSED 08/16 - CUST OUTDOOR LIGHTING DEP - SHORT TERM
253004	OTH DEFERRED CR-OTHR
253005	CL ACC FR OTH DEF DR
253025	DEFERRED COMPENSATION
253027	DEFERRED RENT PAYABLE

Account Number	Account Description
253031	OTHER LONG TERM OPERATING LIABILITIES
253032	UNCERTAIN TAX POSITION - FEDERAL
253033	UNCERTAIN TAX POSITION - STATE
253034	MCI AMORTIZATION
253037	UNEARNED REVENUE - POLE ATTACHMENTS - LONG-TERM
253038	OTHER DEF. CREDIT - COAL CONTRACT - ST
253039	OTHER DEF. CREDIT - COAL CONTRACT - LT
253040	LEASEHOLD INCENTIVE LG&E CENTER LEASE 07012012 - LONG TERM
253041	CANE RUN 7 LTPC LIABILITY
253042	LONG TERM RETAINAGE
253301	PROVISIONS FOR INDEMNITY OBLIGATIONS
253320	UNCERTAIN TAX POSITIONS - INTEREST
253576	DEF GAIN - CARROLLTON SALE/LEASEBACK
254001	FASB 109 ADJ-FED
254002	FASB 109 GR-UP-FED
254003	FASB 109 ADJ-STATE
254004	FASB 109 GR-UP-STATE
254007	REG LIABILITY - GAS SUPPLY CLAUSE
254008	DSM COST RECOVERY
254010	REGULATORY LIABILITY - FAS 158 OPEB
254011	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (CURRENT)
254012	SPARE PARTS
254017	ENVIRONMENTAL COST RECOVERY
254018	REGULATORY LIABILITY FAC
254020	GAS LINE TRACKER- REG LIABILITY
254022	REG LIAB - MUNI GEN TRUE UP
254023	VA FUEL COMPONENT - NON-JURISDICTIONAL CUSTOMERS (CURRENT)
254024	REGULATORY LIABILITY - OST
254025	REG LIABILITY - REFINED COAL - KENTUCKY
254026	REG LIABILITY - REFINED COAL - VIRGINIA
254054	REG. LIABILITY - COAL CONTRACT - ST
254055	REG. LIABILITY - COAL CONTRACT - LT
254056	PAA REG LIABILITY - EMISSION ALLOWANCES - CURRENT
254057	PAA REG LIABILITY - EMISSION ALLOWANCES - LT
254058	PAA REGULATORY LIABILITY - OVEC VALUATION
254090	REGULATORY LIAB FORWARD STARTING SWAPS NOV 2013
254321	MISO EXIT FEE REFUND
254356	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (NON-CURRENT)
255004	ITC TC2
255006	JOB DEVELOP CR
282007	FASB 109 ADJ-FED PRO
282009	FASB 109 ADJ-ST PROP
282503	DTL ON FIXED ASSETS
282703	DTL ON FIXED ASSETS - STATE (NON-CURRENT)
283011	FASB 109 GR-UP-F-OTH
283012	FASB 109 GR-UP-S-OTH
283017	DEF INC TAX - FED EST
283018	DEF INC TAX - ST EST
283418	CLOSED 03/16 - DTL FEDERAL - CURRENT
283514	DTL ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
283515	DTL FEDERAL - NON-CURRENT
283519	DTL ON LIABILITIES - EEI -FED (NON-CURRENT)
283618	CLOSED 03/16 - DTL STATE - CURRENT
283714	DTL ON PROVISIONS FOR PENSIONS - OCI - STATE (NON-CURRENT)
283715	DTL STATE - NON-CURRENT
283719	DTL ON LIABILITIES - EEI - STATE (NON-CURRENT)
403011	DEPREC EXP - STEAM POWER GEN
403012	DEPREC EXP - HYDRO POWER GEN
403013	DEPREC EXP - OTH POWER GEN
403014	DEPREC EXP - TRANSMISSION
403015	DEPREC EXP - DISTRIBUTION
403016	GENERAL DEPRECIATION EXPENSE
403021	DEPREC. EXP. - UNDERGROUND - GAS
403022	DEPREC. EXP. - TRANSMISSION - GAS
403023	DEPREC. EXP. - DISTRIBUTION - GAS
403024	DEPREC. EXP. - GENERAL - GAS
403025	DEPREC. EXP. - COMMON
403026	DEPREC. EXP. - STEAM - ECR
403027	DEPREC EXP - ELECTRIC - DSM
403028	DEPREC EXP - GAS - DSM
403029	DEPREC. EXP. - GENERAL - GLT
403100	DEPREC EXP
403111	DEPREC EXP ARO STEAM
403112	DEPREC EXP ARO TRANSMISSION
403113	DEPREC EXP ARO OTHER PRODUCTION
403114	DEPREC EXP ARO HYDRO
403115	DEPREC EXP ARO DISTRIBUTION
403121	DEPREC EXP ARO GAS UNDERGROUND STORAGE
403122	DEPREC EXP ARO GAS DISTRIBUTION
403123	DEPREC EXP ARO GAS TRANSMISSION
403131	DEPREC EXP ARO COMMON
403181	DEPRECIATION NEUTRALITY - GENERATION DEPRECIATION
403182	DEPRECIATION NEUTRALITY - TRANSMISSION DEPRECIATION
403185	DEPRECIATION NEUTRALITY - DISTRIBUTION DEPRECIATION
403186	DEPRECIATION NEUTRALITY - GAS DEPRECIATION
403187	DEPRECIATION NEUTRALITY - COMMON DEPRECIATON

Account Number	Account Description
404301	AMORT-INTANG GAS PLT
404401	AMT-EL INTAN PLT-RTL
404402	AMT-EL INTAN PLT-WHS
407304	AMORT EXPENSE - OPEN ARO PONDS - KY
407305	AMORT EXPENSE - OPEN ARO PONDS - VA
407306	AMORT EXPENSE - OPEN ARO PONDS - FERC REMAINING MUNI
407307	AMORT EXPENSE - OPEN ARO PONDS - FERC DEPARTING MUNI
407308	AMORT EXPENSE - CLOSED ARO PONDS - KY
407309	AMORT EXPENSE - CLOSED ARO PONDS - VA
407310	AMORT EXPENSE - CLOSED ARO PONDS - FERC REMAINING MUNI
407311	AMORT EXPENSE - CLOSED ARO PONDS - FERC DEPARTING MUNI
407312	AMORT EXPENSE - OPEN ARO PONDS - VA ADJUSTMENT
407313	AMORT EXPENSE - OPEN ARO PONDS - FERC REMAIN ADJUSTMENT
407314	AMORT EXPENSE - OPEN ARO PONDS - FERC DEPART ADJUSTMENT
407315	AMORT EXPENSE - CLOSED ARO PONDS - VA ADJUSTMENT
407316	AMORT EXPENSE - CLOSED ARO PONDS - FERC REMAIN ADJUSTMENT
407317	AMORT EXPENSE - CLOSED ARO PONDS - FERC DEPART ADJUSTMENT
408101	TAX-NON INC-UTIL OPR
408102	REAL AND PERSONAL PROP. TAX
408103	KY PUBLIC SERVICE COMMISSION TAX
408105	FEDERAL UNEMP TAX
408106	FICA TAX
408107	STATE UNEMP TAX
408108	REAL AND PERSONAL PROP TAX - ECR
408109	REAL AND PERSONAL PROP TAX - GLT
408192	REAL AND PERSONAL PROP. TAX - INDIRECT
408195	FEDERAL UNEMP TAX - INDIRECT
408196	FICA TAX - INDIRECT
408197	STATE UNEMP TAX - INDIRECT
408202	TAX-NON INC-OTHER
408203	TC N/A OTHER TAXES
409101	FED INC TAX-UTIL OPR
409102	KY ST INCOME TAXES
409104	FED INC TAXES - EST
409105	ST INC TAXES - EST
409106	FED INC TAX-WKE OPR
409107	KY ST INCOME TAXES-WKE OPR
409108	FED INC TAX - UTIL OPR - SPEC ITEM
409109	KY ST INCOME TAXES - SPEC ITEM
409203	FED INC TAX-OTHER
409206	ST INC TAX-OTHER
409209	FED IN TAXES-OTH EST
409210	ST INC TAXES-OTH EST
409213	FED CURRENT INC TAX-GAIN ON SALE DISCO
409214	ST CURRENT INC TAX-GAIN ON SALE DISCO
409218	FED INC TAX - UTIL OPR - SPEC ITEM-BTL
409219	KY ST INCOME TAXES - SPEC ITEM-BTL
410101	DEF FED INC TAX-OPR
410102	DEF ST INC TAX-OPR
410103	DEF FED INC TAX - OPR EST
410104	DEF ST INC TAX - OPR EST
410106	DEF FED INC TAX-WKE OPR
410107	DEF ST INC TAX-WKE OPR
410108	DEF FED INC TAX-SPEC ITEM
410109	DEF ST INC TAX-SPEC ITEM
410203	DEF FEDERAL INC TX
410204	DEF STATE INC TAX
410208	DEF FED INC TAX-SPEC ITEM-BTL
410209	DEF ST INC TAX-SPEC ITEM-BTL
411100	ACCRETION EXPENSE - NEUTRALITY
411101	FED INC TX DEF-CR-OP
411102	ST INC TAX DEF-CR-OP
411103	ACCRETION EXPENSE - ELECTRIC
411104	ACCRETION EXPENSE - GAS
411105	ACCRETION EXPENSE - COMMON
411106	FED INC TX DEF-CR-WKE OPR
411107	ST INC TAX DEF-CR-WKE OPR
411108	FED INC TX DEF-CR-SPEC ITEM
411109	ST INC TAX DEF-CR-SPEC ITEM
411201	FD INC TX DEF-CR-OTH
411202	ST INC TX DEF-CR-OTH
411208	FED INC TAX DEF-CR-SPEC ITEM-BTL
411209	ST INC TAX DEF-CR-SPEC ITEM-BTL
411403	ITC DEFERRED
411404	AMORTIZATION OF ITC
411802	GAIN-DISP OF ALLOW
412001	SERVICE COMPANY CONSTRUCTION OR OTHER SERVICES EXP
412901	SERVICE COMPANY CONSTRUCTION OR OTHER SERVICES EXP - INDIRECT
415001	REVENUE FROM CUSTOMER SERVICE LINES
415004	MERCHANDISE SALES
416001	EXPENSES FROM CUSTOMER SERVICE LINES
416004	MERCHANDISE COST OF SALES
417004	SERVICE CHARGE AND SUPERVISORY FEE - IMEA AND IMPA
417005	IMPA-WORKING CAPITAL
417006	IMEA-WORKING CAPITAL
417010	OTHER MISC REVENUES FROM NON-UTILITY

Account Number	Account Description
417102	STEAM EXPENSES - (TC ALLOC ONLY)
417105	ELECTRIC EXPENSES - (TC ALLOC ONLY)
417106	MISC EXPENSES - (TC ALLOC ONLY)
417107	RENTS
417108	OPERATION SUPERVISION / ENGR - (TC ALLOC ONLY)
417109	EMISSION ALLOWANCES - (TC ALLOC ONLY)
417110	MTCE SUPERVISION/ENG - (TC ALLOC ONLY)
417111	MTCE OF STRUCTURES - (TC ALLOC ONLY)
417112	MTCE OF BOILER PLANT - (TC ALLOC ONLY)
417113	MTCE OF ELEC PLANT - (TC ALLOC ONLY)
417114	MTCE OF MISC PLANT - (TC ALLOC ONLY)
417120	ADMIN AND GEN SAL - (TC ALLOC ONLY)
417121	OFFICE SUPP AND EXP - (TC ALLOC ONLY)
417123	OUSIDE SVCE EMPLOYED - (TC ALLOC ONLY)
417124	PROPERTY INSURANCE - (TC ALLOC ONLY)
417125	INJURIES AND DAMAGES - (TC ALLOC ONLY)
417126	EMPL PENSIONS/BEN - (TC ALLOC ONLY)
417129	DUPLICATE CGS - CR - (TC ALLOC ONLY)
417130	MISC GENERAL EXP - (TC ALLOC ONLY)
417131	ADMIN AND GEN RENTS - (TC ALLOC ONLY)
417135	MTCE OF GEN PLANT - (TC ALLOC ONLY)
417199	OPERATING EXPENSES OF NON-UTILITY OPERATIONS
418001	NONOPR RENT INCOME
418107	EQUITY IN EARNINGS OF SUBS-EEI
418109	AMORTIZATION-EEI PAA
418110	EQUITY IN EARNINGS OF CONSOLIDATED SUBSIDIARIES
418111	IMPAIRMENT OF SUBS - EEI
419002	INT INC-US TREAS SEC
419005	INT INC-FED TAX PMT
419006	INT INC-ST TAX PMT
419014	DIVS FROM INVESTMENT
419150	ALLOW FOR FUNDS USED DURING CONSTRUC-EQUITY
419205	INTEREST INCOME FROM FINANCIAL HOLDINGS
419206	INTEREST INCOME FROM OTHER LOANS & RECEIVABLES
419207	INTEREST INCOME FROM SPECIAL FUNDS
419208	INT INC - PPL ENERGY FUNDING
419209	INT INC-ASSOC CO
419211	DIVIDENDS FROM OVEC
420003	AMORTIZATION OF ITC
421001	MISC NONOPR INCOME
421003	KM LIFE INS - CASH SURRENDER VALUE
421005	MISC NONOPR INCOME-NON-UTILITY ASSET DEPR
421006	AOCI ADJUSTMENT OF SUBSIDIARY - EEI
421101	GAIN-PROPERTY DISP
421105	GAIN ON ARO SETTLEMENT
421201	LOSS-PROPERTY DISP
421301	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS
421306	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS - CENTURY RECEIVABLE
426101	DONATIONS
426120	SPONSORSHIP/OTHER COMMUNITY RELATIONS
426190	SPONSORSHIP/OTHER COMMUNITY RELATIONS - INDIRECT
426191	DONATIONS - INDIRECT
426201	LIFE INSURANCE
426301	PENALTIES
426391	PENALTIES - INDIRECT
426401	EXP-CIVIC/POL/REL
426491	EXP-CIVIC/POL/REL - INDIRECT
426501	OTHER DEDUCTIONS
426502	SERP
426504	OFFICERS TIA
426505	OFFICER LONG-TERM INCENT
426509	SERP - NON-MERCER
426511	LOSS ON ASSET IMPAIRMENT
426513	OTHER OFFICER BENEFITS
426514	AOCI ADJUSTMENT OF SUBSIDIARY - EEI
426517	SERP - INTEREST
426518	GOODWILL IMPAIRMENT
426557	AMORT OF OCI-PCB JC2003A $128M
426558	AMORT OF REG ASSET - SWAP TERMINATION
426560	ECONOMIC DEVELOPMENT RIDER-CREDITS EARNED
426591	OTHER DEDUCTIONS - INDIRECT
427007	INT EXP-KU REVOLVING CREDIT $400M 12/14
427019	INT EXP-LGE REVOLVING CREDIT $400M 12/14
427100	INTEREST EXPENSE
427150	INT EXP-PCB JC2000A $25M 11/16
427154	INT EXP-PCB JC2007A $31M 06/17
427155	INT EXP-PCB JC2005A $40M 07/19
427164	INT EXP-SWAP-MS $32M 10/32 3.657%
428009	AM EXP-FMB KU2010 $250M 11/15
428010	AM EXP-FMB KU2010 $500M 11/20
428011	AM EXP-FMB KU2010 $750M 11/40
428023	AM EXP-FMB KU2013 $250M 11/43
428090	OTHER AMORT OR DEBT DISCOUNT AND EXP
428190	OTHER AMORT-REACQ DEBT
428200	AM DISC-LONG TERM DEBT
430002	INT-DEBT TO ASSOC CO

Account Number	Account Description
430004	I/C INT EXP CEP RESERVES
430100	I/C INT EXP DEBT WITH PPL CAPITAL FUNDING
430101	I/C INTEREST EXPENSE - LT-NOTES CEP RESERVES
431002	INT-CUST DEPOSITS
431003	INT-FED TAX DEFNCY
431004	INT-OTHER TAX DEFNCY
431008	INT-DSM COST RECOVER
431009	INT-SHORT TERM DEBT-CP
431015	INTEREST ON RATES REFUND-RETAIL
431016	INTEREST ON REFUNDS - MUNICIPALS
431017	UTP INTEREST - FED INC TAX
431018	UTP INTEREST - STATE INC TAX
431104	INTEREST EXPENSE FROM FINANCIAL LIABILITIES
431200	OTHER INTEREST EXPENSE
432001	ALLOW FOR FUNDS USED DURING CONSTRUC-BORROWED
433100	REVENUES - DISCONTINUED OPERATIONS
433101	OTHER EXPENSES - DISCONTINUED OPERATIONS
433102	FED CURRENT INCOME TAXES - DISCO OPS
433103	ST CURRENT INCOME TAXES - DISCO OPS
433104	FED DEFERRED INCOME TAXES - DISCO OPS
433105	ST DEFERRED INCOME TAXES - DISCO OPS
438003	COMMON STK DIVS DECL - LEL
438005	COMMON STK DIVS DECL - PARENT FM KU
438006	COMMON STOCK DIV DECLARED PPL FM LKE
440010	RESID (FUEL) - KWH - (STAT ONLY)
440011	RESID (FUEL) - CUS - (STAT ONLY)
440012	ELECTRIC RESIDENTIAL KW
440101	ELECTRIC RESIDENTIAL DSM
440102	ELECTRIC RESIDENTIAL ENERGY NON-FUEL REV
440103	ELECTRIC RESIDENTIAL ENERGY FUEL REV
440104	ELECTRIC RESIDENTIAL FAC
440111	ELECTRIC RESIDENTIAL ECR
440112	ELECTRIC RESIDENTIAL MSR
440113	ELECTRIC RESIDENTIAL OSS TRACKER (ESM)
440114	ELECTRIC RESIDENTIAL VDT
440116	ELECTRIC RESIDENTIAL DEMAND ECR
440117	ELECTRIC RESIDENTIAL ENERGY ECR
440118	ELECTRIC RESIDENTIAL DEMAND CHG REV
440119	ELECTRIC RESIDENTIAL CUST CHG REV
440121	ELECTRIC RESIDENTIAL SOLAR CAPACITY CHG
440122	ELECTRIC RESIDENTIAL SOLAR ENERGY CREDIT
440123	ELECTRIC RESIDENTIAL SOLAR FAC OFFSET
440124	ELECTRIC RESIDENTIAL SOLAR OST OFFSET
442010	SM COMRC/IND SALE-EL - KWH - (STAT ONLY)
442011	SM COMRC/IND SALE-EL - CUS - (STAT ONLY)
442012	SM COMRC/IND SALE-EL - KW - (STAT ONLY)
442020	LG COMMERC SALES-EL - KWH - (STAT ONLY)
442021	LG COMMERC SALES-EL - CUS - (STAT ONLY)
442022	LG COMMERC SALES-EL - KW - (STAT ONLY)
442025	KU COMMERCIAL SALES - KWH - (STAT ONLY)
442026	KU COMMERCIAL SALES - CUS - (STAT ONLY)
442027	KU COMMERCIAL SALES - KW - (STAT ONLY)
442030	LG INDUSTR SALES-El-OTHER - KWH - (STAT ONLY)
442031	LG INDUSTR SALES-EL-OTHER - CUS - (STAT ONLY)
442034	LG INDUSTR SALES-EL-OTHER - KW - (STAT ONLY)
442035	KU INDUSTRIAL SALES - KWH - (STAT ONLY)
442036	KU INDUSTRIAL SALES - CUS - (STAT ONLY)
442037	KU INDUSTRIAL SALES - KW - (STAT ONLY)
442065	MINE POWER SALES (COAL) - KWH - (STAT ONLY)
442066	MINE POWER SALES (COAL) - CUS - (STAT ONLY)
442067	MINE POWER SALES (COAL) - KW - (STAT ONLY)
442101	ELECTRIC SMALL COMMERCIAL DSM
442102	ELECTRIC SMALL COMMERCIAL ENERGY NON-FUEL REV
442103	ELECTRIC SMALL COMMERCIAL ENERGY FUEL REV
442104	ELECTRIC SMALL COMMERCIAL FAC
442105	ELECTRIC SMALL COMMERCIAL STOD
442111	ELECTRIC SMALL COMMERCIAL ECR
442112	ELECTRIC SMALL COMMERCIAL MSR
442113	ELECTRIC SMALL COMMERCIAL OSS TRACKER (ESM)
442114	ELECTRIC SMALL COMMERCIAL VDT
442116	ELECTRIC SMALL COMMERCIAL DEMAND ECR
442117	ELECTRIC SMALL COMMERCIAL ENERGY ECR
442118	ELECTRIC SMALL COMMERCIAL DEMAND CHG REV
442119	ELECTRIC SMALL COMMERCIAL CUST CHG REV
442201	ELECTRIC LARGE COMMERCIAL DSM
442202	ELECTRIC LARGE COMMERCIAL ENERGY NON-FUEL REV
442203	ELECTRIC LARGE COMMERCIAL ENERGY FUEL REV
442204	ELECTRIC LARGE COMMERCIAL FAC
442205	ELECTRIC LARGE COMMERCIAL STOD
442211	ELECTRIC LARGE COMMERCIAL ECR
442212	ELECTRIC LARGE COMMERCIAL MSR
442213	ELECTRIC LARGE COMMERCIAL OSS TRACKER (ESM)
442214	ELECTRIC LARGE COMMERCIAL VDT
442216	ELECTRIC LARGE COMMERCIAL DEMAND ECR
442217	ELECTRIC LARGE COMMERCIAL ENERGY ECR
442218	ELECTRIC LARGE COMMERCIAL DEMAND CHG REV

Account Number	Account Description
442219	ELECTRIC LARGE COMMERCIAL CUST CHG REV
442221	ELECTRIC LARGE COMMERCIAL SOLAR CAPACITY CHG
442222	ELECTRIC LARGE COMMERCIAL SOLAR ENERGY CREDIT
442223	ELECTRIC LARGE COMMERCIAL SOLAR FAC OFFSET
442224	ELECTRIC LARGE COMMERCIAL SOLAR OST OFFSET
442301	ELECTRIC INDUSTRIAL DSM
442302	ELECTRIC INDUSTRIAL ENERGY NON-FUEL REV
442303	ELECTRIC INDUSTRIAL ENERGY FUEL REV
442304	ELECTRIC INDUSTRIAL FAC
442305	ELECTRIC INDUSTRIAL STOD
442311	ELECTRIC INDUSTRIAL ECR
442312	ELECTRIC INDUSTRIAL MSR
442313	ELECTRIC INDUSTRIAL OSS TRACKER (ESM)
442314	ELECTRIC INDUSTRIAL VDT
442316	ELECTRIC INDUSTRIAL DEMAND ECR
442317	ELECTRIC INDUSTRIAL ENERGY ECR
442318	ELECTRIC INDUSTRIAL DEMAND CHG REV
442319	ELECTRIC INDUSTRIAL CUST CHG REV
442321	ELECTRIC INDUSTRIAL SOLAR CAPACITY CHG
442322	ELECTRIC INDUSTRIAL SOLAR ENERGY CREDIT
442323	ELECTRIC INDUSTRIAL SOLAR FAC OFFSET
442324	ELECTRIC INDUSTRIAL SOLAR OST OFFSET
442601	MINE POWER DSM
442602	MINE POWER ENERGY NON-FUEL REV
442603	MINE POWER ENERGY FUEL REV
442604	MINE POWER FAC
442605	MINE POWER STOD
442611	MINE POWER ECR
442612	MINE POWER MSR
442613	MINE POWER OSS TRACKER (ESM)
442614	MINE POWER VDT
442616	MINE POWER DEMAND ECR
442617	MINE POWER ENERGY ECR
442618	MINE POWER DEMAND CHG REV
442619	MINE POWER CUST CHG REV
444010	PUBLIC ST/HWY LIGHTS - KWH - (STAT ONLY)
444011	PUBLIC ST/HWY LIGHTS - CUS - (STAT ONLY)
444012	PUBLIC ST/HWY LIGHTS - KW - (STAT ONLY)
444101	ELECTRIC STREET LIGHTING DSM
444102	ELECTRIC STREET LIGHTING ENERGY NON-FUEL REV
444103	ELECTRIC STREET LIGHTING ENERGY FUEL REV
444104	ELECTRIC STREET LIGHTING FAC
444105	ELECTRIC STREET LIGHTING STOD
444111	ELECTRIC STREET LIGHTING ECR
444112	ELECTRIC STREET LIGHTING MSR
444113	ELECTRIC STREET LIGHTING OSS TRACKER (ESM)
444114	ELECTRIC STREET LIGHTING VDT
444117	ELECTRIC STREET LIGHTING ENERGY ECR
444118	ELECTRIC STREET LIGHTING DEMAND CHG REV
444119	ELECTRIC STREET LIGHTING CUST CHG REV
445010	SALES-PUB AUTH-ELEC - KWH - (STAT ONLY)
445011	SALES-PUB AUTH-ELEC - CUS - (STAT ONLY)
445012	SALES-PUB AUTH-ELEC - KW - (STAT ONLY)
445030	MUNICIPAL PUMPING - KWH - (STAT ONLY)
445031	MUNICIPAL PUMPING - CUS - (STAT ONLY)
445032	MUNICIPAL PUMPING - KW - (STAT ONLY)
445101	ELECTRIC PUBLIC AUTH DSM
445102	ELECTRIC PUBLIC AUTH ENERGY NON-FUEL REV
445103	ELECTRIC PUBLIC AUTH ENERGY FUEL REV
445104	ELECTRIC PUBLIC AUTH FAC
445105	ELECTRIC PUBLIC AUTH STOD PCR
445111	ELECTRIC PUBLIC AUTH ECR
445112	ELECTRIC PUBLIC AUTH MSR
445113	ELECTRIC PUBLIC AUTH OSS TRACKER (ESM)
445114	ELECTRIC PUBLIC AUTH VDT
445116	ELECTRIC PUBLIC AUTH DEMAND ECR
445117	ELECTRIC PUBLIC AUTH ENERGY ECR
445118	ELECTRIC PUBLIC AUTH DEMAND CHG REV
445119	ELECTRIC PUBLIC AUTH CUST CHG REV
445121	ELECTRIC PUBLIC AUTH SOLAR CAPACITY CHG
445122	ELECTRIC PUBLIC AUTH SOLAR ENERGY CREDIT
445123	ELECTRIC PUBLIC AUTH SOLAR FAC OFFSET
445124	ELECTRIC PUBLIC AUTH SOLAR OST OFFSET
445301	MUNI PUMPING DSM
445302	MUNI PUMPING ENERGY NON-FUEL REV
445303	MUNI PUMPING ENERGY FUEL REV
445304	MUNI PUMPING FAC
445305	MUNICIPAL PUMPING STOD
445311	MUNI PUMPING ECR
445312	MUNI PUMPING MSR
445313	MUNI PUMPING OSS TRACKER (ESM)
445314	MUNI PUMPING VDT
445316	MUNI PUMPING DEMAND ECR
445317	MUNI PUMPING ENERGY ECR
445318	MUNI PUMPING DEMAND CHG REV
445319	MUNI PUMPING CUST CHG REV

Account Number	Account Description
447005	I/C SALES - OSS
447006	I/C SALES NL
447010	FIRM SALES - ENERGY-OTHER - KWH - (STAT ONLY)
447011	FIRM SALES - ENERGY-OTHER - CUS - (STAT ONLY)
447017	FIRM SALES - ENERGY-OTHER - KW - (STAT ONLY)
447021	FIRM SALES - MUNI/BEREA - KWH - (STAT ONLY)
447022	FIRM SALES - MUNI/BEREA - CUS
447023	FIRM SALES - MUNICIPALS - KW - (STAT ONLY)
447049	SPOT SALES - ENERGY
447050	OFF-SYSTEM SALES REVENUE TO THIRD PARTIES
447051	SPOT SALES - ENERGY - KW - (STAT ONLY)
447100	BROKERED SALES
447110	SETTLED SWAP REVENUE
447200	BROKERED PURCHASES
447302	RESALE MUNICIPALS BASE REV
447303	RESALE MUNICIPALS BASE REV FUEL
447304	RESALE MUNICIPALS FAC
447318	RESALE MUNICIPALS DEMAND CHG REV
447319	RESALE MUNICIPALS CUST CHG REV
447402	ELEC WLSE SPECIAL CONTRACT - NON-FUEL REV
447403	ELEC WLSE SPECIAL CONTRACT - FUEL REV
447418	ELEC WLSE SPECIAL CONTRACT - DEMAND CHG REV
447419	ELEC WLSE SPECIAL CONTRACT - CUST CHG REV
449102	PROVISION FOR RATE REFUND/COLLECTION
449105	RATE REFUNDS-RETAIL
450001	FORFEITED DISC/LATE PAYMENT CHARGE-ELEC
450002	FORFEITED DISC/LATE PAYMENT CHARGE - MUNI INTEREST
451001	RECONNECT CHRG-ELEC
451002	TEMPORARY SERV-ELEC
451004	OTH SERVICE REV-ELEC
454001	CATV ATTACH RENT
454002	OTH RENT-ELEC PROP
454003	RENT FRM FIBER OPTIC
454006	FACILITY CHARGES
454007	ELECTRIC VEHICLE CHARGING STATION RENTAL
454900	I/C JOINT USE RENT REVENUE-ELEC-INDIRECT
454901	I/C JOINT USE RENT REVENUE-ELEC-INDIRECT (PPL ELIM)
456003	COMP-TAX REMIT-ELEC
456004	COMP-STBY PWR-H2O CO
456007	RET CHECK CHRG-ELEC
456008	OTHER MISC ELEC REVS
456022	COAL RESALE REVENUES
456028	EXCESS FACILITIES CHARGES/NRB ELECTRIC REV (ENDED 04/09)
456029	GYPSUM REVENUES
456030	FORFEITED REFUNDABLE ADVANCES
456031	SSP - SUBSCRIPTION FEES
456090	REVENUE FROM RENEWABLE ENERGY CREDITS
456099	POWER DELIVERED TO GOVERNMENT (STAT ONLY)
456101	BASE OTHER ELECTRIC REVENUES-WHEELING-MISO - (STAT ONLY)
456102	ANCILLARY SERVICE SCHEDULE 1-MISO
456103	ANCILLARY SERVICE SCHEDULE 2-MISO
456105	ANCILLARY SERVICE SCHEDULE 1-OSS-MISO
456106	ANCILLARY SERVICE SCHEDULE 2-OSS-MISO
456109	NL TRANSMISSION OF ELECTRIC ENERGY-3RD PARTY
456110	ELEC WLSE SPECIAL CONTRACT - TRANSMISSION
456114	INTERCOMPANY TRANSMISSION REVENUE - RETAIL SOURCING OSS
456116	INTERCOMPANY TRANSMISSION REVENUE - MUNICIPALS
456118	INTRACOMPANY TRANSMISSION REVENUE - NATIVE LOAD
456119	INTRACOMPANY TRANSMISSION REVENUE - RETAIL SOURCING OSS
456124	I/C TRANSMISSION RETAIL REVENUE - NATIVE LOAD
456127	TRANSMISSION SERVICE REVENUE - CC (OSS-STAT ONLY)
456130	THIRD PARTY ENERGY NATIVE LOAD TRANSMISSION
456131	THIRD PARTY SCHEDULE 1 NATIVE LOAD TRANSMISSION
456132	THIRD PARTY SCHEDULE 2 NATIVE LOAD TRANSMISSION
456133	THIRD PARTY SCHEDULE 3 NATIVE LOAD TRANSMISSON
456134	THIRD PARTY DEMAND NATIVE LOAD TRANSMISSION
456135	THIRD PARTY SCHEDULE 5 NATIVE LOAD TRANSMISSION
456136	THIRD PARTY SCHEDULE 6 NATIVE LOAD TRANSMISSION
456140	INTERCOMPANY NATIVE LOAD ENERGY TRANSMISSION
456141	INTERCOMPANY NATIVE LOAD SCH 1 TRANSMISSION
456142	INTERCOMPANY NATIVE LOAD SCH 2 TRANSMISSION
456143	INTERCOMPANY NATIVE LOAD DEMAND TRANSMISSION
456150	INTERCOMPANY RETAIL SOURCE ENERGY TRANSMISSION
456151	INTERCOMPANY RETAIL SOURCE SCH 1 TRANSMISSION
456152	INTERCOMPANY RETAIL SOURCE SCH 2 TRANSMISSION
456153	INTERCOMPANY RETAIL SOURCE DEMAND TRANSMISSION
456160	INTRACOMPANY NATIVE LOAD ENERGY TRANSMISSION
456161	INTRACOMPANY NATIVE LOAD SCH 1 TRANSMISSION
456162	INTRACOMPANY NATIVE LOAD SCH 2 TRANSMISSION
456163	INTRACOMPANY NATIVE LOAD DEMAND TRANSMISSION
456170	INTRACOMPANY RETAIL SOURCE ENERGY TRANSMISSION
456171	INTRACOMPANY RETAIL SOURCE SCH 1 TRANSMISSION
456172	INTRACOMPANY RETAIL SOURCE SCH 2 TRANSMISSION
456173	INTRACOMPANY RETAIL SOURCE DEMAND TRANSMISSION
456198	INTRACOMPANY TRANSMISSION REVENUE ELIMINATION - NL
456199	INTRACOMPANY TRANSMISSION REVENUE ELIMINATION - RETAIL SOURCING OSS

Account Number	Account Description
457101	DIRECT COSTS CHARGED
457201	INDIRECT COSTS CHARGED
480010	RESID VARIABLE(FUEL) - MCF - (STAT ONLY)
480011	RESID VARIABLE(FUEL) - CUS - (STAT ONLY)
480101	GAS RESIDENTIAL DSM
480102	GAS RESIDENTIAL ENERGY REV
480104	GAS RESIDENTIAL GSC
480106	GAS RESIDENTIAL GLT
480107	GAS RESIDENTIAL WNA
480114	GAS RESIDENTIAL VDT
480119	GAS RESIDENTIAL CUST CHG REV
481010	COMMERCIAL SALES-GAS - CU - (STAT ONLY)
481011	COMMERCIAL SALES-GAS - MCF - (STAT ONLY)
481020	INDUSTRIAL SALES-GAS - CU - (STAT ONLY)
481021	INDUSTRIAL SALES-GAS - MCF - (STAT ONLY)
481101	GAS COMMERCIAL DSM
481102	GAS COMMERCIAL ENERGY REV
481104	GAS COMMERCIAL GSC
481105	GAS COMMERCIAL CASHOUT
481106	GAS COMMERICAL GLT
481107	GAS COMMERCIAL WNA
481114	GAS COMMERCIAL VDT
481119	GAS COMMERCIAL CUST CHG REV
481201	GAS INDUSTRIAL DSM
481202	GAS INDUSTRIAL ENERGY REV
481204	GAS INDUSTRIAL GSC
481205	GAS INDUSTRIAL CASHOUT
481206	GAS INDUSTRIAL GLT
481214	GAS INDUSTRIAL VDT
481219	GAS INDUSTRIAL CUST CHG REV
482010	SALES-PUB AUTH-GAS - CUS - (STAT ONLY)
482011	SALES-PUB AUTH-GAS - MCF - (STAT ONLY)
482101	GAS PUBLIC AUTH DSM
482102	GAS PUBLIC AUTH ENERGY REV
482104	GAS PUBLIC AUTH GSC
482105	GAS PUBLIC AUTH CASHOUT
482106	GAS PUBLIC AUTH GLT
482107	GAS PUBLIC AUTH WNA
482114	GAS PUBLIC AUTH VDT
482119	GAS PUBLIC AUTH CUST CHG REV
483001	OFF SYSTEM SALES FOR RESALE (MCF) - (STAT ONLY)
484001	GAS INTERDEPARTMENTAL SALES
484102	GAS INTERDEPARTMENTAL BASE REVENUES
484104	GAS INTERDEPARTMENTAL GSC
484105	PADDYS RUN CASHOUT - INTRACOMPANY
484106	GAS INTERDEPARTMENTAL GLT
484119	GAS INTERDEPARTMENTAL CUSTOMER CHARGE
487001	FORFEITED DISC/LATE PAYMENT CHARGE-GAS
488001	RECONNECT CHRG-GAS
488003	INSPECTION CHARGE-GAS
488004	METER TESTS-GAS
488005	GAS METER PULSE SERVICE
489201	GAS TRANSPORT INTERDEPARTMENTAL - BASE
489204	GAS TRANSPORT INTERDEP - CASHOUT OFO/UCDI
489215	GAS TRANSPORT - INTERDEPARTMENTAL
489301	GAS TRANSPORT - DSM
489302	GAS TRANSPORT - INDUSTRIAL
489304	GAS TRANSPORT - CASHOUT OFO/UCDI
489310	GAS TRANSPORT - CUSTOMERS (STAT ONLY)
489312	GAS TRANSPORT - DIRECT PAY - STATS ONLY
489314	GAS TRANSPORT - VDT
489319	TRANSPORT GAS - CUSTOMER CHARGE
489322	GAS TRANSPORT - COMMERCIAL
489332	GAS TRANSPORT - PUBLIC AUTHORITY
493001	RENT-GAS PROPERTY
493900	I/C JOINT USE RENT REVENUE-GAS-INDIRECT
493901	I/C JOINT USE RENT REVENUE FROM PPL-GAS-INDIRECT
495002	COMP-TAX REMIT-GAS
495005	RET CHECK CHRG-GAS
495006	OTHER GAS REVENUES
500100	OPER SUPER/ENG
500900	OPER SUPER/ENG - INDIRECT
501001	FUEL-COAL - TON
501002	FUEL-COAL - BTU - (STAT ONLY)
501003	COAL ADDITIVES
501004	FUEL COAL - TO SOURCE UTILITY OSS
501005	FUEL COAL - OSS
501006	FUEL COAL - OFFSET
501007	FUEL COAL - TO SOURCE UTILITY RETAIL
501009	OSS INCREMENTAL COAL EXPENSE
501020	START-UP OIL -GAL
501021	START-UP OIL - BTU - (STAT ONLY)
501022	STABILIZATION OIL - GAL
501023	STABILIZATION OIL - BTU - (STAT ONLY)
501024	GENERATION OIL - GAL - (STAT ONLY)
501025	GENERATION OIL - BTU - (STAT ONLY)

Account Number	Account Description
501026	COAL RESALE EXPENSES
501030	PETROLEUM COKE - TON - (STAT ONLY)
501090	FUEL HANDLING
501091	FUEL SAMPLING AND TESTING
501092	FUEL HANDLING-GALS - (STAT ONLY)
501099	KWH GENERATED-COAL - (STAT ONLY)
501100	START-UP GAS - MCF
501101	START-UP GAS - BTU - (STAT ONLY)
501102	STABILIZATION GAS - MCF
501103	STABILIZATION GAS - BTU - (STAT ONLY)
501110	GENERATION GAS - MAIN BOILER -MCF - (STAT ONLY)
501200	BOTTOM ASH DISPOSAL
501201	CLOSED 08/16 - PLANT-ECR BOTTOM ASH DISPOSAL
501202	BOTTOM ASH PROCEEDS
501203	ECR BOTTOM ASH DISPOSAL
501250	FLY ASH PROCEEDS
501251	FLY ASH DISPOSAL
501252	CLOSED 08/16 - PLANT-ECR FLY ASH DISPOSAL
501253	ECR FLY ASH DISPOSAL
501299	KWH GENERATED-OIL - (STAT ONLY)
501990	FUEL HANDLING - INDIRECT
501993	FUELS PROCUREMENT - INDIRECT
502001	OTHER WASTE DISPOSAL
502002	BOILER SYSTEMS OPR
502003	SDRS OPERATION
502004	SDRS-H2O SYS OPR
502005	SLUDGE STAB SYS OPR
502006	SCRUBBER REACTANT EX
502011	ECR OTHER WASTE DISPOSAL
502012	LANDFILL OPERATION
502013	ECR LANDFILL OPERATIONS
502021	OTHER WASTE DISPOSAL - RETAIL
502022	OTHER WASTE DISPOSAL - OSS
502023	OTHER WASTE DISPOSAL - OFFSET
502024	SCRUBBER REACTANT - RETAIL
502025	REACTANT - EXTERNAL OSS
502026	SCRUBBER REACTANT - OFFSET
502027	SCRUBBER REACTANT - TO SOURCE UTILITY OSS
502056	ECR SCRUBBER REACTANT EX
502057	ECR SCRUBBER REACTANT OSS OFFSET
502058	ECR SCRUBBER REACTANT EX - OSS
502100	STM EXP(EX SDRS.SPP)
502900	STM EXP(EX SDRS.SPP) - INDIRECT
504001	STEAM XFERRED - CR - PROJECT USE
505100	ELECTRIC SYS OPR
506001	STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT
506051	ECR STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT
506100	MISC STM PWR EXP
506102	MISC STM PWR EXP-GALS - (STAT ONLY)
506103	MISC STM PWR EXP-BTU - (STAT ONLY)
506104	NOX REDUCTION REAGENT
506105	OPERATION OF SCR/NOX REDUCTION EQUIP
506106	SCR/NOX - RETAIL
506107	AMMONIA - EXTERNAL OSS
506108	SCR/NOX - OFFSET
506109	SORBENT INJECTION OPERATION
506110	MERCURY MONITORS OPERATIONS
506111	ACTIVATED CARBON
506112	SORBENT REACTANT - REAGENT ONLY
506113	LIQUID INJECTION - REAGENT ONLY
506114	AMMONIA - TO SOURCE UTILITY OSS
506150	ECR MERCURY MONITORS OPERATIONS
506151	ECR ACTIVATED CARBON
506152	ECR SORBENT REACTANT - REAGENT ONLY
506153	ECR LIQUID INJECTION - REAGENT ONLY
506154	ECR NOX REDUCTION REAGENT
506155	ECR OPERATION OF SCR/NOX REDUCTION EQUIP
506156	ECR BAGHOUSE OPERATIONS
506159	ECR SORBENT INJECTION OPERATION
506160	ECR OTHER STEAM EXPENSE OSS OFFSET
506161	ECR ACTIVATED CARBON - OSS
506162	ECR SORBENT REACTANT - REAGENT ONLY - OSS
506163	ECR NOX REDUCTION REAGENT - OSS
506900	MISC STM PWR EXP - INDIRECT
507100	RENTS-STEAM
507900	I/C JOINT USE RENT EXPENSE-GEN-INDIRECT
509002	SO2 EMISSION ALLOWANCES
509003	NOX EMISSION ALLOWANCES
509004	EMISSION ALLOWANCES - RETAIL
509007	EMISSION ALLOWANCES - EXTERNAL OSS
509008	EMISSION ALLOWANCES - OFFSET
509009	EMISSION ALLOWANCES - TO SOURCE UTILITY OSS
509052	ECR SO2 EMISSION ALLOWANCES
509053	ECR NOX EMISSION ALLOWANCES
510100	MTCE SUPER/ENG - STEAM
510900	MTCE SUPER/ENG - STEAM - INDIRECT

Account Number	Account Description
511100	MTCE-STRUCTURES
512005	MAINTENANCE-SDRS
512011	INSTR/CNTRL-ENVRNL
512015	SDRS-COMMON H2O SYS
512016	MAINTENANCE - MERC CONTROL
512017	MTCE-SLUDGE STAB SYS
512051	ECR INSTR/CNTRL-ENVRNL
512055	ECR MAINTENANCE-SDRS
512056	ECR MAINTENANCE - MERC CONTROL
512100	MTCE-BOILER PLANT
512101	MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512102	SORBENT INJECTION MAINTENANCE
512103	MERCURY MONITORS MAINTENANCE
512105	LANDFILL MAINTENANCE
512106	CCP SYSTEM MAINTENANCE
512107	ECR LANDFILL MAINTENANCE
512108	ECR CCP SYSTEM MAINTENANCE
512151	ECR MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512152	ECR SORBENT INJECTION MAINTENANCE
512153	ECR MERCURY MONITORS MAINTENANCE
512156	ECR BAGHOUSE MAINTENANCE
513100	MTCE-ELECTRIC PLANT
513900	MTCE-ELECTRIC PLANT - BOILER
514100	MTCE-MISC/STM PLANT
535100	OPER SUPER/ENG-HYDRO
536100	WATER FOR POWER
536101	KWH GENERATED-HYDRO - (STAT ONLY)
538100	ELECTRIC EXPENSES - HYDRO
539100	MISC HYD PWR GEN EXP
540100	RENTS-HYDRO
541100	MTCE-SUPER/ENG - HYDRO
542100	MAINT OF STRUCTURES - HYDRO
543100	MTCE-RES/DAMS/WATERW
544100	MTCE-ELECTRIC PLANT
545100	MTCE-MISC HYDAULIC PLANT
546100	OPER SUPER/ENG - TURBINES
546900	OPER SUPER/ENG - TURBINES - INDIRECT
547010	KWH GEN-OTH PWR-OIL - (STAT ONLY)
547020	KWH GEN-OTH PWR-GAS - (STAT ONLY)
547021	KWH GEN-OTH PWR-SOLAR - (STAT ONLY)
547030	FUEL-GAS - MCF
547031	FUEL-GAS - BTU - (STAT ONLY)
547040	FUEL-OIL - GAL
547041	FUEL-OIL - BTU - (STAT ONLY)
547051	FUEL - TO SOURCE UTILITY OSS
547052	FUEL - OSS
547053	FUEL - OFFSET
547054	FUEL - TO SOURCE UTILITY RETAIL
547056	FUEL - GAS - INTRACOMPANY
547057	FUEL - GAS - INTRACOMPANY - BTU - (STAT ONLY)
547058	OSS INCREMENTAL CT EXPENSE
548010	GENERATION EXP
548910	GENERATION EXP - INDIRECT
549001	SO2 EMISSION ALLOWANCES
549002	AIR QUALITY EXPENSES
549003	NOX EMISSION ALLOWANCES
549100	MISC OTH PWR GEN EXP
549900	MISC OTH PWR GEN EXP - INDIRECT
550100	RENTS-OTH PWR
551100	MTCE-SUPER/ENG - TURBINES
551900	MTCE-SUPER/ENG - TURBINES - INDIRECT
552100	MTCE-STRUCTURES - OTH PWR
553010	MTCE-GEN/ELECT EQ
553200	MTCE-HEAT RECOVERY STM GEN
554100	MTCE-MISC OTH PWR GEN
555010	OSS POWER PURCHASES
555011	MONTHLY FUEL ADJUSTMENT (MFA) RELATED CAPACITY/TOLLING PURCHASE POWER
555015	NL POWER PURCHASES - ENERGY
555016	NL POWER PURCHASES - DEMAND
555017	DEMAND FOR TOLLING/CAPACITY AGREEMENTS
555020	OSS I/C POWER PURCHASES
555025	NL I/C POWER PURCHASES
555080	PURCHASE POWER NATIVE LOAD - SQF AND LQF TARIFF
555085	PURCHASE POWER NATIVE LOAD DEMAND - LQF TARIFF
555101	INAD INTER REC-KWH - (STAT ONLY)
555110	INAD INTER DEL-KWH - (STAT ONLY)
556100	SYS CTRL / DISPATCHING
556900	SYS CTRL / DISPATCHING - INDIRECT
557100	OTH POWER SUPPLY EXP
557110	MARKET FEES - NATIVE LOAD
557111	MARKET FEES - OFF SYSTEM SALES
557206	MISO DAY 2 OTHER - NATIVE LOAD
557207	MISO DAY 2 OTHER - OFF SYSTEM SALES
557208	RTO OTHER (NON-MISO) - NL
557209	RTO OTHER (NON-MISO) - OSS
557211	RTO OPERATING RESRV (NON-MISO) - NL

Account Number	Account Description
557212	RTO OPERATING RESRV (NON-MISO) - OSS
557999	KU PLANT ALLOCATION CLEARING ACCOUNT
560100	OP SUPER/ENG-SSTOPER
560900	OP SUPER/ENG-SSTOPER - INDIRECT
561100	LOAD DISPATCH-WELOB
561190	LOAD DISPATCH - INDIRECT
561201	LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM
561291	LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM - INDIRECT
561301	LOAD DISPATCH-TRANSMISSION SERVICE AND SCHEDULING
561391	LOAD DISPATCH-TRANSMISSION SERVICE AND SCHEDULING - INDIRECT
561402	MISO DAY 1 SCH 10 - RESERVE
561403	NL MISO D1 SCHEDULE 10 - SCHEDULING, SYSTEM CONTROLS
561501	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT
561590	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT - INDIRECT
561601	TRANSMISSION SERVICE STUDIES
561801	MISO DAY 1 SCH 10 - LOAD
561802	MISO DAY 1 SCH 10 - RESERVE
561803	NL MISO D1 SCHEDULE 10 - RELIABILITY PLANNING
562010	STA EXP-SUBST OPER
563100	OTHER INSP-ELEC TRAN
563900	OTHER INSP-ELEC TRAN - INDIRECT
565002	TRANSMISSION ELECTRIC OSS
565005	TRANSMISSION ELECTRIC NATIVE LOAD
565006	TRANSMISSION ELECTRIC OSS - MISO
565007	TRANSMISSION ELECTRIC OSS - 3RD PARTY
565014	INTERCOMPANY TRANSMISSION EXPENSE
565016	INTERCOMPANY TRANSMISSION EXPENSE - MUNICIPALS
565018	INTRACOMPANY TRANSMISSION EXPENSE - NATIVE LOAD
565019	INTRACOMPANY TRANSMISSION EXPENSE - OSS
565024	I/C TRANSMISSION RETAIL EXPENSE - NATIVE LOAD
565198	INTRACOMPANY TRANSMISSION EXPENSE OFFSET - NATIVE LOAD
565199	INTRACOMPANY TRANSMISSION EXPENSE ELIMINATION - RETAIL SOURCING OSS
566100	MISC TRANS EXP-SSTMT
566122	REACTIVE SUPPLY & VOLTAGE CONTROL - NL
566140	INDEPENDENT OPERATOR
566150	EKPC DEPANCAKING SETTLEMENT
566151	TRANSMISSION DEPANCAKING EXPENSES
566900	MISC TRANS EXP-SSTMT - INDIRECT
567100	RENTS-ELEC/SUBSTATION OPERATIONS
567900	I/C JOINT USE RENT EXPENSE-TRANS-INDIRECT
569100	MTCE-STRUCT-SSTMTCE
569101	MAINTENANCE OF COMPUTER HARDWARE
570010	MTCE-ST EQ-SSTMTCE
570900	MTCE-ST EQ-SSTMTCE - INDIRECT
571100	MTCE OF OVERHEAD LINES
573100	MTCE-MISC TR PLT-SSTMT
573900	MTCE-MISC TR PLT-SSTMT INDIRECT
575701	MISO DAY 2 SCH 17-MARKET ADMIN FEE-OSS
575702	MISO DAY 2 SCH 16-FTR ADMIN FEE-NL
575703	MISO DAY 2 SCH 17-MARKET ADMIN FEE-NL
575704	MISO DAY 1 SCH 10 - RESERVE
575708	NL MISO D1 SCHEDULE 10 - MKT ADMIN
580100	OP SUPER/ENG-SSTOPER
580900	OP SUPER/ENG-SSTOPER - INDIRECT
581100	SYS CTRL/SWITCH-DIST
581900	SYS CTRL/SWITCH-DIST - INDIRECT
582100	STATION EXP-SSTOPER
583001	OPR-O/H LINES
583003	O/H LOAD/VOLT TEST
583004	INST/REMV TEMP SERV
583005	CUST COMPL RESP-O/H
583008	INST/REMV TRANSF/REG
583009	INSPC O/H LINE FACIL
583010	LOC O/H ELEC FAC-BUD
583100	O/H LINE EXP-SSTOPER
584001	OPR-UNDERGRND LINES
584002	INSPC U/G LINE FACIL
584003	LOAD/VOLT TEST-U/G
584005	RESP-U/G CUST COMPL
584008	INST/RMV/REPL TRANSF
585100	STREET LIGHTING AND SIGNAL SYST EXP
586100	METER EXP
586101	INPECT/TEST METERS
586900	METER EXP - INDIRECT
587100	CUST INSTALLATION EXP
588100	MISC DIST EXP-SUBSTATION OPERATIONS
588900	MISC DIST EXP-SUBSTATION OPERATIONS - INDIRECT
589100	RENTS-DISTR / SUBSTAT OPER
590100	MTCE/SUPER/ENG-SSTMT
590900	MTCE/SUPER/ENG-SSTMT - INDIRECT
591003	MTCE-MISC STRUCT-DIS
592100	MTCE-ST EQ-SSTMTCE
593001	MTCE-POLE/FIXT-DISTR
593002	MTCE-COND/DEVICE-DIS
593003	MTCE-SERVICES
593004	TREE TRIMMING

Account Number	Account Description
593005	MINOR EXEMPT EXPENSE
593904	TREE TRIMMING - INDIRECT
594001	MTCE-ELEC MANHOL ETC
594002	MTCE-U/G COND ETC
595100	MTCE-TRANSF/REG
596100	MTCE OF STREET LIGHTING AND SIGNALS
597100	MAINTENANCE OF METERS
598100	MTCE OF MISC DISTRIBUTION PLANT
598900	MTCE OF MISC DISTRIBUTION PLANT - INDIRECT
803001	GAS TRANS LINE PURCH
803002	PURCHASED GAS REFUND
803003	GAS COST ACTUAL ADJ
803004	GAS COST BALANCE ADJ
803006	PURCHASED GAS - WHOLESALE SALES
803007	WHOLESALE SALES MARGIN
803008	ACQ AND TRANS INCENTIVE
803009	PBR RECOVERY
803010	END USERS GAS PURCHASE (MCF ONLY) - (STAT ONLY)
806001	EXCHANGE GAS - INJECTIONS
806002	EXCHANGE GAS - WITHDRAWALS
807401	PURCH GAS CALC EXP
807501	OTHER PURCH GAS EXP
807502	GAS PROCUREMENT EXP
808101	GAS W/D FROM STOR-DR
808201	GAS DELD TO STOR-CR
810001	GAS-COMP STA FUEL-CR
812010	GAS-FUEL-ELEC GEN-CR - MCF - (STAT ONLY)
812011	GAS-FUEL-ELEC GEN-CR - BTU - (STAT ONLY)
812020	GAS-CITY GATE-CR
812030	GAS-OTH DEPT-CR
812040	GAS-START/STABIL-CR - MCF - (STAT ONLY)
812041	GAS-START/STABIL-CR - BTU - (STAT ONLY)
813001	OTH GAS SUPPLY EXP
813003	LOST AND UNACCOUNTED FOR GAS - TRANSPORTS (STAT ONLY)
814003	SUPV-STOR/COMPR STA
816100	WELLS EXPENSE
817100	LINES EXPENSE
818100	COMPR STATION EXP
819100	COMPR STA FUEL-U/G
821100	PURIFICATION EXP
823100	GAS LOSSES
824100	OPR-U/G STO/COMPR
825100	ROYALTIES
826100	RENTS-STORAGE FIELDS
830100	MTCE SUPRV AND ENGR - STOR COMPR
832100	MTC-RESERVOIRS/WELLS
833100	MTCE-LINES
834100	MTCE-COMP STA EQUIP
835100	MTCE-M/R EQ-COMPR
836100	MTCE-PURIFICATION EQUP
837100	MTCE-OTHER EQUIP
850100	OPR SUPV AND ENGR
851100	SYS CTRL/DSPTCH-GAS
852100	OPR-COM EQ-GAS TRANS
856100	MAINS EXPENSES
860100	RENTS-GAS TRANS
863100	MTCE-GAS MAINS-TRANS
871100	DISTR LOAD DISPATCH
874001	OTHER MAINS/SERV EXP
874002	LEAK SUR-DIST MN/SVC
874005	CHEK STOP BOX ACCESS
874006	PATROLLING MAINS
874007	CHEK/GREASE VALVES
874008	OPR-ODOR EQ
874110	GLT - OTHER MAINS / SERV EXP.
875100	MEAS/REG STA-GENERAL
876100	MEAS/REG STA-INDUSTRIAL
877100	MEAS/REG STA-CITY GATE
878100	METER/REG EXPENSE
878110	GLT - METER/REG EXP.
879100	CUST INSTALL EXPENSE
879110	GLT-CUSTOMER INSTALL
880016	GAS LOST / UNACCT FOR (MCF) - (STAT ONLY)
880100	OTH GAS DISTR EXPENSE
880110	GAS RISER AND LEAK MITIGATION TRACKER EXPENSES - BUDGET ONLY
880900	OTH GAS DISTR EXPENSE - INDIRECT
881100	RENTS-GAS DISTR
886100	MTCE-GAS DIST STRUCT
887100	MTCE-GAS MAINS-DISTR
887110	GLT- MTCE GAS MAINS DIST.
889100	MTCE-M/R STA EQ-GENL
890100	MTCE-M/R STA EQ-INDL
891100	MTCE-M/R ST EQ-CITY GATE
892100	MTCE-OTH SERVICES
892110	GLT-MTCE-OTHER SERVICE
892900	MTCE-OTH SERVICES - INDIRECT

Account Number	Account Description
893100	MTCE-METER/HOUSE REG
894100	MTCE-OTHER EQUIP
894900	MTCE-OTHER EQUIP - INDIRECT
901001	SUPV-CUST ACCTS
901900	SUPV-CUST ACCTS - INDIRECT
902001	METER READ-SERV AREA
902002	METER READ-CLER/OTH
902900	METER READ-SERV AREA - INDIRECT
903001	AUDIT CUST ACCTS
903002	BILL SPECIAL ACCTS
903003	PROCESS METER ORDERS
903006	CUST BILL/ACCTG
903007	PROCESS PAYMENTS
903008	INVEST THEFT OF SVC
903011	MAINTENANCE-CIS
903012	PROC CUST CNTRT/ORDR
903013	HANDLE CREDIT PROBS
903022	COLL OFF-LINE BILLS
903023	PROC BANKRUPT CLAIMS
903025	MTCE-ASST PROGRAMS
903030	PROC CUST REQUESTS
903031	PROC CUST PAYMENTS
903032	DELIVER BILLS-REG
903035	COLLECTING-OTHER
903036	CUSTOMER COMPLAINTS
903038	MISC CASH OVERAGE/SHORTAGE
903901	AUDIT CUST ACCTS - INDIRECT
903902	BILL SPECIAL ACCTS - INDIRECT
903903	PROCESS METER ORDERS - INDIRECT
903906	CUST BILL/ACCTG - INDIRECT
903907	PROCESS PAYMENTS - INDIRECT
903908	INVESTIGATE THEFT OF SERVICE - INDIRECT
903909	PROC EXCEPTION PMTS - INDIRECT
903912	PROC CUST CNTRT/ORDR - INDIRECT
903922	COLLECT OFF-LINE BILLS - INDIRECT
903930	PROC CUST REQUESTS - INDIRECT
903931	PROC CUST PAYMENTS - INDIRECT
903935	COLLECTING-OTHER - INDIRECT
903936	CUSTOMER COMPLAINTS - INDIRECT
904001	UNCOLLECTIBLE ACCTS
904002	UNCOLLECTABLE ACCTS - WHOLESALE
904003	UNCOLL ACCTS - A/R MISC
904004	UNCOLL ACCTS - A/R MISC - SPEC ITEM
904005	UNCOLLECTIBLE ACCTS - GSC
905001	MISC CUST SERV EXP
905002	MISC CUST BILL/ACCTG
905003	MISC COLLECTING EXP
905900	MISC CUST SERV EXP - INDIRECT
907001	SUPV-CUST SER/INFO
907900	SUPV-CUST SER/INFO - INDIRECT
908001	CUST MKTG/ASSIST
908004	DSM - ENERGY AUDIT
908005	DSM CONSERVATION PROG
908006	DSM - HVAC
908007	DSM - CONSERVATION
908009	MISC MARKETING EXP
908011	DSM CONSERVATION PROGRAM - GAS EXPENSE RECLASS
908901	CUST MKTG/ASSIST - INDIRECT
908902	RES CONS/ENG ED PROG - INDIRECT
908909	MISC MARKETING EXP - INDIRECT
909004	MISC CUST COM-SER/IN
909005	MEDIA RELATIONS
909010	PRINT ADVER-SER/INFO
909011	OTH ADVER-SER/INFO
909013	SAFETY PROGRAMS
909910	PRINT ADVER-SER/INFO - INDIRECT
909911	OTHER ADVER-SER/INFO - INDIRECT
910001	MISC CUST SER/INFO
910900	MISC CUST SER/INFO - INDIRECT
912003	GEN MKTG AND MKTG PGMS
913012	OTH ADVER-SALES
913912	OTH ADVER-SALES - INDIRECT
920100	OTHER GENERAL AND ADMIN SALARIES
920900	OTHER GENERAL AND ADMIN SALARIES - INDIRECT
921002	EXP-GEN OFFICE EMPL
921003	GEN OFFICE SUPPL/EXP
921004	OPR-GEN OFFICE BLDG
921902	INDIRECT EMPLOYEE OFFICE EXPENSE ALLOCATION
921903	GEN OFFICE SUPPL/EXP - INDIRECT
921904	I/C OPR-GEN OFFICE BLDG - INDIRECT
921905	OFC EQUIP DEPR COST OF SALES OFFSET-INDIRECT (LKS ONLY)
922001	A/G SAL TRANSFER-CR
922002	OFF SUPP/EXP TRAN-CR
922003	TRIMBLE CTY TRAN-CR
923100	OUTSIDE SERVICES
923101	OUTSIDE SERVICES - AUDIT FEES

Account Number	Account Description
923301	OUTSIDE SERVICES - AUDIT FEES - OTHER
923302	OUTSIDE SERVICES - TAX SERVICES - OTHER
923900	OUTSIDE SERVICES - INDIRECT
924100	PROPERTY INSURANCE
924900	PROPERTY INSURANCE - INDIRECT
925001	PUBLIC LIABILITY
925002	WORKERS COMP EXPENSE - BURDENS
925003	AUTO LIABILITY
925004	SAFETY AND INDUSTRIAL HEALTH
925100	OTHER INJURIES AND DAMAGES
925900	OTHER INURIES AND DAMAGES - INDIRECT
925902	WORKERS COMP EXPENSE - BURDENS INDIRECT
925904	SAFETY & INDUSTRIAL HEALTH - INDIRECT
926001	TUITION REFUND PLAN
926002	GROUP LIFE INSURANCE EXPENSE - BURDENS
926003	MEDICAL INSURANCE EXPENSE - BURDENS
926004	DENTAL INSURANCE EXPENSE - BURDENS
926005	LONG TERM DISABILITY EXPENSE - BURDENS
926019	OTHER BENEFITS EXPENSE - BURDENS
926100	EMPLOYEE BENEFITS - NON-BURDEN
926101	PENSION SERVICE COST - BURDENS
926102	401K EXPENSE - BURDENS
926105	FASB 112 POST EMPLOYMENT EXPENSE - BURDENS
926106	FASB 106 (OPEB) SERVICE COST - BURDENS
926110	EMPLOYEE WELFARE
926112	PENSION EXP- VA
926113	PENSION EXP- FERC AND TENN.
926115	ADOPTION ASSISTANCE PROGRAM
926116	RETIREMENT INCOME EXPENSE - BURDENS
926117	PENSION NON SERVICE COST - BURDENS
926118	FASB 106 POST RETIREMENT NON SERVICE COST EXPENSE - BURDENS
926900	EMPLOYEE BENEFITS - NON-BURDEN - INDIRECT
926901	TUITION REFUND PLAN - INDIRECT
926902	GROUP LIFE INSURANCE EXPENSE - BURDENS INDIRECT
926903	MEDICAL INSURANCE EXPENSE - BURDENS INDIRECT
926904	DENTAL INSURANCE EXPENSE - BURDENS INDIRECT
926905	LONG TERM DISABILITY EXPENSE - BURDENS INDIRECT
926906	PENSION EXP- VA - INDIRECT
926907	PENSION EXP- FERC AND TENN. - INDIRECT
926910	EMPLOYEE WELFARE - INDIRECT
926911	PENSION SERVICE COST - BURDENS INDIRECT
926912	401K EXPENSE - BURDENS INDIRECT
926915	FASB 112 POST EMPLOYMENT EXPENSE - BURDENS INDIRECT
926916	FASB 106 (OPEB) SERVICE COST - BURDENS INDIRECT
926917	PENSION NON SERVICE COSTS - BURDENS INDIRECT
926918	FASB 106 (OPEB) NON SERVICE COSTS - BURDENS INDIRECT
926919	OTHER BENEFITS EXPENSE - BURDENS INDIRECT
926990	RETIREMENT INCOME EXPENSE - BURDENS INDIRECT
926995	ADOPTION ASSISTANCE PROGRAM - INDIRECT
927001	ELEC SUPPL W/O CH-DR
927002	OTH ITEMS W/O CH-DR
927003	CITY OF LOU GAS FRAN
928001	FORMAL CASES - FERC
928002	REG UPKEEP ASSESSMTS
928003	AMORTIZATION OF RATE CASE EXPENSES
928006	FORMAL CASES - TENNESSEE
928007	FORMAL CASES - VIRGINIA
928008	FORMAL CASES - KENTUCKY
929001	FRANCHISE REQMTS-CR
929002	ELEC USED-ELEC DEPT
929003	GAS USED-GAS DEPT
929004	ELECTRICITY USED - OTHER DEPARTMENTS
929005	ELECTRICITY USED BY ELECTRIC DEPARTMENT - ODP
929006	KWH SOURCES - ODP - (STAT ONLY)
929007	ODP FREE LIGHTING
930101	GEN PUBLIC INFO EXP
930191	GEN PUBLIC INFO EXP - INDIRECT
930201	MISC CORPORATE EXP
930202	ASSOCIATION DUES
930203	RESEARCH WORK
930207	OTHER MISC GEN EXP
930223	SUSPENSE - PPL
930271	MISC CORPORATE EXP - INDIRECT
930272	ASSOCIATION DUES - INDIRECT
930274	RESEARCH AND DEVELOPMENT EXPENSES - INDIRECT
930277	OTHER MISC GEN EXP - INDIRECT
931004	RENTS-CORPORATE HQ
931100	RENTS-OTHER
931900	I/C JOINT USE RENT EXPENSE-INDIRECT
931904	RENTS - CORPORATE HQ (INDIRECT)
935101	MTCE-GEN PLANT
935191	MTCE-GEN PLANT - INDIRECT
935203	SOFTWARE MTCE AGREEMENTS
935391	MTCE-COMMUNICATION EQ - INDIRECT
935401	MTCE-OTH GEN EQ
935402	MAINT. OF NON-BONDABLE GENERAL PLANT

Account Number	Account Description
935403	MNTC BONDABLE PROPERTY
935488	MTCE-OTH GEN EQ - INDIRECT
951001	ECR RATE BASE - 2016 PLANS (STAT ONLY)
951002	ECR RATE BASE - PRE-2016 PLANS (STAT ONLY)
951003	ECR RATE OF RETURN - 2016 PLANS (STAT ONLY)
951004	ECR RATE OF RETURN - PRE-2016 PLANS (STAT ONLY)
951005	ECR JURISDICTIONAL FACTOR (STAT ONLY)
951006	ECR - ESTIMATED OPERATING EXPENSES (STAT ONLY)
951101	DSM DCR RECOVERABLE PROGRAM EXPENSE (STAT ONLY)
951102	DSM DRLS - LOST SALES (STAT ONLY)
951103	DSM DSMI - INCENTIVE (STAT ONLY)
951104	DSM RECOVERABLE DCCR PROGRAM EXPENSE (STAT ONLY)
951105	DSM RECOVERABLE DCCR CAPITAL EXPENSE (STAT ONLY)
951106	DSM RECOVERABLE INTEREST ON DCCR CAPITAL (STAT ONLY)
951107	DSM DBA STAT ONLY - (BALANCING ADJUSTMENT)
951201	GLT RATE BASE (STAT ONLY)
951202	GLT DEPRECIATION SAVINGS (STAT ONLY)
951203	GLT COST OF CAPITAL (STAT ONLY)
951204	CHANGE IN YTD AVERAGE GLT RATE BASE, APPLIED TO ALL MONTHS (STAT ONLY)
951301	ACTUAL MONTHLY COOLING DEGREE DAYS (STAT ONLY)
951302	ACTUAL MONTHLY HEATING DEGREE DAYS (STAT ONLY)
951303	NORMAL MONTHLY COOLING DEGREE DAYS (STAT ONLY)
951304	NORMAL MONTHLY HEATING DEGREE DAYS (STAT ONLY)

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(n)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The latest twelve (12) months of the monthly managerial reports providing financial results of operations in comparison to the forecast.

Response:

See attached.

Net Income Continuing Operations - Louisville Gas and Electric Company

November 2015

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	105,863,960	119,737,239	(13,873,279)
Cost of Revenues	(38,313,160)	(53,514,788)	15,201,628
Electric Margin	50,390,992	51,189,527	(798,535)
Gas Margin	17,159,808	15,032,924	2,126,884
O&M	(25,935,556)	(25,439,050)	(496,506)
Other Income & Expenses	(389,476)	(29,997)	(359,478)
Depreciation	(11,525,463)	(12,076,188)	550,725
Property tax	(2,200,607)	(2,279,612)	79,005
Interest	(5,926,884)	(5,983,131)	56,247
Income Tax	(8,280,272)	(7,839,800)	(440,472)
Net Income from Ongoing Operations	**13,292,543**	**12,574,673**	**717,870**
Special Items	0	0	0
Net Income	**13,292,543**	**12,574,673**	**717,870**

Net Income Continuing Operations - Louisville Gas and Electric Company

December 2015

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	118,281,840	148,668,062	(30,386,222)
Cost of Revenues	(45,420,516)	(71,269,524)	25,849,008
Electric Margin	53,290,632	56,047,257	(2,756,624)
Gas Margin	19,570,693	21,351,282	(1,780,589)
O&M	(27,189,623)	(26,165,551)	(1,024,072)
Other Income & Expenses	(696,203)	(122,383)	(573,820)
Depreciation	(11,497,465)	(12,204,672)	707,207
Property tax	(2,163,845)	(2,279,612)	115,767
Interest	(5,815,645)	(5,809,481)	(6,164)
Income Tax	(9,455,912)	(11,601,023)	2,145,111
Net Income from Ongoing Operations	**16,042,632**	**19,215,817**	**(3,173,185)**
Special Items	0	0	0
Net Income	**16,042,632**	**19,215,817**	**(3,173,185)**

Net Income Continuing Operations - Louisville Gas and Electric Company

January 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	147,037,252	155,256,417	(8,219,166)
Cost of Revenues	(62,622,060)	(72,638,848)	10,016,789
Electric Margin	59,878,817	57,297,592	2,581,225
Gas Margin	24,536,375	25,319,977	(783,602)
O&M	(23,445,300)	(24,737,649)	1,292,349
Other Income & Expenses	(408,829)	(468,840)	60,011
Depreciation	(11,719,367)	(12,064,975)	345,608
Property tax	(2,237,891)	(2,326,405)	88,514
Interest	(5,860,262)	(5,916,157)	55,895
Income Tax	(15,746,802)	(14,341,069)	(1,405,733)
Net Income from Ongoing Operations	**24,996,740**	**22,762,474**	**2,234,266**
Special Items	0	0	0
Net Income	**24,996,740**	**22,762,474**	**2,234,266**

Net Income Continuing Operations - Louisville Gas and Electric Company

February 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	128,597,525	140,071,794	(11,474,269)
Cost of Revenues	(53,436,055)	(64,000,920)	10,564,865
Electric Margin	53,133,030	53,630,737	(497,707)
Gas Margin	22,028,440	22,440,137	(411,697)
O&M	(25,996,143)	(25,914,870)	(81,273)
Other Income & Expenses	(551,834)	(158,116)	(393,717)
Depreciation	(11,714,063)	(12,074,137)	360,075
Property tax	(2,127,102)	(2,326,405)	199,303
Interest	(5,833,797)	(5,897,510)	63,714
Income Tax	(11,154,653)	(11,461,052)	306,399
Net Income from Ongoing Operations	**17,783,879**	**18,238,783**	**(454,904)**
Special Items	0	0	0
Net Income	**17,783,879**	**18,238,783**	**(454,904)**

Net Income Continuing Operations - Louisville Gas and Electric Company

March 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	111,470,131	127,755,548	(16,285,417)
Cost of Revenues	(42,261,528)	(56,302,374)	14,040,846
Electric Margin	53,505,612	53,386,658	118,954
Gas Margin	15,702,992	18,066,516	(2,363,525)
O&M	(27,846,276)	(27,877,024)	30,748
Other Income & Expenses	(800,687)	(663,224)	(137,463)
Depreciation	(11,741,371)	(12,086,553)	345,183
Property tax	(2,332,669)	(2,326,405)	(6,264)
Interest	(5,848,700)	(5,886,007)	37,307
Income Tax	(7,610,190)	(8,498,789)	888,599
Net Income from Ongoing Operations	**13,028,711**	**14,115,172**	**(1,086,461)**
Special Items	0	0	0
Net Income	**13,028,711**	**14,115,172**	**(1,086,461)**

Net Income Continuing Operations - Louisville Gas and Electric Company

April 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	102,819,830	109,972,903	(7,153,074)
Cost of Revenues	(39,010,712)	(45,800,402)	6,789,689
Electric Margin	50,946,384	51,645,118	(698,734)
Gas Margin	12,862,734	12,527,384	335,350
O&M	(27,848,670)	(30,699,202)	2,850,532
Other Income & Expenses	(415,743)	(211,530)	(204,213)
Depreciation	(11,759,391)	(12,104,608)	345,217
Property tax	(2,317,723)	(2,326,405)	8,682
Interest	(5,809,187)	(5,903,307)	94,120
Income Tax	(5,988,683)	(4,936,338)	(1,052,345)
Net Income from Ongoing Operations	**9,669,720**	**7,991,112**	**1,678,608**
Special Items	0	0	0
Net Income	**9,669,720**	**7,991,112**	**1,678,608**

Net Income Continuing Operations - Louisville Gas and Electric Company

May 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	101,605,627	108,349,053	(6,743,426)
Cost of Revenues	(35,550,637)	(41,307,238)	5,756,601
Electric Margin	55,807,938	56,703,445	(895,507)
Gas Margin	10,247,053	10,338,371	(91,318)
O&M	(28,149,578)	(28,480,061)	330,482
Other Income & Expenses	(111,479)	(122,106)	10,628
Depreciation	(11,771,598)	(12,129,436)	357,838
Property tax	(2,583,833)	(2,326,405)	(257,428)
Interest	(5,784,490)	(5,919,795)	135,305
Income Tax	(6,739,992)	(6,935,048)	195,056
Net Income from Ongoing Operations	**10,914,022**	**11,128,965**	**(214,944)**
Special Items	0	0	0
Net Income	**10,914,022**	**11,128,965**	**(214,944)**

Net Income Continuing Operations - Louisville Gas and Electric Company

June 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	118,761,430	121,106,225	(2,344,795)
Cost of Revenues	(40,378,809)	(45,228,298)	4,849,489
Electric Margin	69,170,771	66,623,277	2,547,494
Gas Margin	9,211,851	9,254,650	(42,800)
O&M	(26,696,337)	(27,812,999)	1,116,662
Other Income & Expenses	(404,663)	(132,201)	(272,462)
Depreciation	(11,935,856)	(12,099,844)	163,989
Property tax	(2,384,403)	(2,326,405)	(57,998)
Interest	(5,738,795)	(5,927,564)	188,769
Income Tax	(11,961,161)	(10,429,771)	(1,531,390)
Net Income from Ongoing Operations	**19,261,407**	**17,149,141**	**2,112,265**
Special Items	0	0	0
Net Income	**19,261,407**	**17,149,141**	**2,112,265**

Net Income Continuing Operations - Louisville Gas and Electric Company

July 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	126,233,391	130,798,908	(4,565,517)
Cost of Revenues	(44,558,526)	(49,386,782)	4,828,256
Electric Margin	72,724,593	72,295,039	429,553
Gas Margin	8,950,272	9,117,086	(166,814)
O&M	(22,694,529)	(26,118,723)	3,424,194
Other Income & Expenses	(220,467)	(43,211)	(177,256)
Depreciation	(11,853,108)	(12,068,336)	215,228
Property tax	(2,390,029)	(2,331,142)	(58,887)
Interest	(5,838,288)	(5,924,457)	86,169
Income Tax	(14,943,479)	(13,493,662)	(1,449,816)
Net Income from Ongoing Operations	**23,734,965**	**21,432,594**	**2,302,372**
Special Items	0	0	0
Net Income	**23,734,965**	**21,432,594**	**2,302,372**

Net Income Continuing Operations - Louisville Gas and Electric Company

August 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	128,828,283	133,313,910	(4,485,627)
Cost of Revenues	(45,232,332)	(50,160,150)	4,927,819
Electric Margin	74,514,762	73,928,818	585,944
Gas Margin	9,081,189	9,224,942	(143,753)
O&M	(25,381,047)	(27,748,385)	2,367,337
Other Income & Expenses	(125,214)	(81,356)	(43,857)
Depreciation	(11,679,475)	(12,098,765)	419,290
Property tax	(2,400,144)	(2,331,142)	(69,002)
Interest	(5,897,300)	(5,976,676)	79,375
Income Tax	(14,621,667)	(13,491,873)	(1,129,794)
Net Income from Ongoing Operations	**23,491,104**	**21,425,563**	**2,065,541**
Special Items	0	0	0
Net Income	**23,491,104**	**21,425,563**	**2,065,541**

Net Income Continuing Operations - Louisville Gas and Electric Company

September 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	114,731,427	114,411,575	319,852
Cost of Revenues	(42,070,191)	(41,631,942)	(438,249)
Electric Margin	63,298,317	63,311,388	(13,071)
Gas Margin	9,362,919	9,468,245	(105,326)
O&M	(24,052,828)	(27,615,224)	3,562,396
Other Income & Expenses	(2,195,898)	(84,633)	(2,111,264)
Depreciation	(11,659,489)	(12,134,098)	474,609
Property tax	(2,388,197)	(2,331,142)	(57,055)
Interest	(6,012,437)	(5,979,018)	(33,420)
Income Tax	(9,868,331)	(9,284,825)	(583,507)
Net Income from Ongoing Operations	**16,484,055**	**15,350,693**	**1,133,362**
Special Items	0	0	0
Net Income	**16,484,055**	**15,350,693**	**1,133,362**

Net Income Continuing Operations - Louisville Gas and Electric Company

October 2016

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	102,259,207	106,946,849	(4,687,642)
Cost of Revenues	(36,333,303)	(40,909,967)	4,576,665
Electric Margin	54,982,635	54,579,927	402,708
Gas Margin	10,943,270	11,456,955	(513,685)
O&M	(25,684,086)	(29,948,782)	4,264,696
Other Income & Expenses	(98,631)	(121,288)	22,657
Depreciation	(11,652,183)	(12,172,298)	520,115
Property tax	(2,392,841)	(2,331,142)	(61,699)
Interest	(5,808,138)	(5,949,285)	141,147
Income Tax	(7,776,850)	(5,943,227)	(1,833,623)
Net Income from Ongoing Operations	**12,513,176**	**9,570,859**	**2,942,316**
Special Items	0	0	0
Net Income	**12,513,176**	**9,570,859**	**2,942,316**

Louisville Gas and Electric Company
Case No. 2016-00371
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/18; Base Period 12ME 2/28/17)

Filing Requirement
807 KAR 5:001 Section 16(7)(o)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior to the base period, each month of the base period, and any subsequent months, as they become available.

Response:

The Companies have only one monthly budget variance (performance) report used for management reporting to the CEO and executive officers. Beginning January 2016, this performance report includes separate income statement, balance sheet and other analyses for Kentucky Utilities Company and Louisville Gas and Electric Company. Prior to 2016, this report included combined information for LG&E and KU Energy LLC. Certain information responsive to this request is being provided under seal pursuant to a Petition for Confidential Protection.

See attached for the monthly reports for:

- The twelve months prior to the base period - March 2015 through February 2016.
- Each month of the base period - As of the date of the filing only the months of March 2016 through October 2016 are available. The Company will provide this data for the remaining periods requested in the upcoming months as it becomes available.

Performance Report

March 2015

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Kentucky Regulated Dashboard — March 2015

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.07	1.82	1.26	1.37	1.41	1.03
Employee lost-time incidents	0	0	0	0	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,763	2,719	9,271	8,832	36,534	34,582
Utility EFOR	3.7%	5.9%	3.1%	5.9%	N/A	5.9%
Utility EAF	70.8%	73.6%	86.1%	85.9%	N/A	83.8%
Steam Fleet Commercial Availability	93.0%	92.0%	96.7%	92.0%	N/A	92.0%
Combined SAIFI	0.07	0.07	0.21	0.23	N/A	1.19
Combined SAIDI (minutes)	6.29	7.38	17.47	21.03	N/A	106.60
GwH Sales						
Residential	871	878	3,289	3,013	11,118	10,842
Commercial	613	610	1,936	1,889	7,964	7,916
Industrial	790	791	2,375	2,361	10,038	10,024
Municipals	152	150	501	474	1,913	1,890
Other	231	214	696	657	2,761	2,723
Off-System Sales	35	12	183	148	281	311
Total	2,692	2,654	8,980	8,542	34,075	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.97%			
Commercial			-1.00%			
Industrial			2.49%			
Municipal			-1.25%			
Other			-0.55%			
Total			-0.26%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(1)	8.0%	6.3%	11.9%	9.7%	8.9%	8.9%
Electric Margins	$146	$133	$460	$427	$1,774	$1,774
Gas Margins	13	16	60	60	165	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$1	$8	$8	$20	$51	$48
ECR	69	62	186	187	564	569
Generation	18	12	28	27	142	149
Transmission	5	7	12	13	62	59
Electric Distribution	12	11	32	28	161	162
Gas Distribution	5	5	14	13	84	83
Customer Services	1	1	3	3	17	17
IT and Other	4	3	7	8	38	38
Total	$116	$109	$291	$300	$1,121	$1,125
O&M ($ millions)(2)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$44	46	$111	113	$477	471
General Counsel & HR	3	3	9	9	40	40
Finance, IT, & Supply Chain	7	7	19	21	81	81
Burdens & Other Charges	16	15	44	46	169	176
Total	$70	$72	$184	$189	$767	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,483	3,591	3,483	3,591	3,545	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	7	3	N/A	9
NERC Possible Violations(3)	0	0	1	0	N/A	7

Variance Explanations

• YTD generation volumes and GWh sales were impacted by cold weather. Generation volumes were also impacted by excellent plant availability.

• Current month higher electric margins due to favorable demand and energy revenue and production expenses. Electric margins also include net true-up adjustments of $6 million including KU's supply contracts with certain municipalities and the impact of the bonus depreciation extension.

• YTD higher electric margins due to a combination of favorable weather and plant/system performance resulting in $22 million from favorable demand and energy revenue and production expenses, $3 million in ECR revenues and $3 million from the sale of excess generation. Electric margins also include net true-up adjustments of $6 million including KU's supply contracts with certain municipalities and the impact of the bonus depreciation extension.

• YTD lower O&M due to $2 million of labor and benefit savings, $1 million of lower outside services due to timing of consulting services and contract support, $1 million timing for maintenance changes and $1 million lower uncollectible accounts.

• Seven environmental events have occurred YTD. The events were a result of SO2, NOx, and CO exceedances at Mill Creek and Trimble County. All events were short timeframe limits which were exceeded and were all due to equipment malfunctions.

Major Developments

• The service territories experienced a rare March snow storm which brought nearly a foot of snow to most of Kentucky with some areas reaching two feet. Near record cold temperatures followed the storm, however, LKE's electric and gas systems performed well and successfully managed the increased demand. KU and the Combined Utilities' system established new all-time March peak loads, and all-time March total daily energy usage records were also set for LG&E, KU and the Combined Utilities' system.

• There has been significant activity in the Kentucky rate case as the discovery phase of the case is complete. Intervening parties filed testimony on March 6 and public meetings were also held in Louisville and Lexington.

• LKE has achieved additional construction milestones on its Cane Run 7 project as both combustion turbines completed first fire and initial synchronization. LG&E also retired Cane Run 6 to help facilitate transmission work for the new plant site. In addition, Ghent 1 fabric filter baghouse construction and Mill Creek 1 and 2 FGD and fabric filter baghouses, are all progressing with tie-in outages. Ghent 1 represents an eleven-week outage and Mill Creek 1 and 2 are engaged in eight-week outages.

• The 2015 Kentucky General Assembly session concluded in March as lawmakers passed legislation on such issues as heroin, dating violence, and a gas tax. A bill encouraging community-based energy efficiency passed both chambers, however, it has no adverse impact on the Company or its energy efficiency programs. Perennially-offered bills seeking to impose a Renewable Portfolio Standard, prohibit utilities from recovering franchise fees on bills, and prohibit customer disconnection for failure to pay during winter months, all failed to gain a committee hearing.

Significant Future Events

• The execution of LKE's construction plan continues in 2015. The commissioning activities for Cane Run 7 have positioned the project to likely begin commercial operations during the second quarter. Site work for Brown Solar is also expected to commence in the second quarter as responses for the EPC contract are currently under review. The Trimble County 1 and Brown 3 fabric filter EPC contracts are underway as planned with tie-in outages projected for October.

• The Company will file its rebuttal rate case testimony on April 14th, followed by settlement discussions on April 16-17th. The public evidentiary hearing is also set to begin April 21st.

(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issue for YTD Actual is believed to be minimal risk.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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Blake

Income Statement: Actual vs. Budget and Forecast (Month) **March 2015**

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 236	$ 226	$ 9	See Electric Margin variance explanation below.
Gas Revenues	32	38	(6)	Due to lower pricing from favorable fuel supply expense which is an offset as shown below. Monthly results also include weather normalization adjustment.
Total Revenues	267	264	3	
Cost of Sales:				
Fuel Electric Costs	76	77	1	
Gas Supply Expenses	19	22	3	
Purchased Power	5	5	0	
Other Electric Cost	9	11	2	
Total Cost of Sales	108	115	7	
Gross Margin:				
Electric Margin	146	133	13	Due to favorable demand and energy revenue and production expenses of $4 million. Margins also include net true-up adjustments of $6 million including KU's supply contracts with certain municipalities and the impact of the bonus depreciation extension.
Gas Margin	13	16	(3)	
Total Gross Margin	159	149	10	
Operating Expenses:				
O&M	70	72	2	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	4	5	0	
Total Operating Expenses	104	106	3	
Other income (expense)	0	(0)	1	
EBIT	56	42	13	
Interest Expense	14	15	1	
Income from Ongoing Operations before income taxes	42	28	14	
Income Tax Expense	18	10	(9)	Due to higher pre-tax income and certain effects of the bonus depreciation extension.
Net Income (loss) from ongoing operations	**23**	**18**	**$ 5**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 23	$ 18	$ 5	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 20	$ 15	$ 5	
Earnings Per Share	$ 0.03	$ 0.02	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — March 2015

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 759	$ 725	$ 34	See Electric Margin variance explanation below.
Gas Revenues	141	147	(5)	Due to lower pricing from favorable fuel supply expense which is an offset as shown below.
Total Revenues	900	872	28	
Cost of Sales:				
Fuel Electric Costs	255	251	(4)	
Gas Supply Expenses	81	87	5	See Gas Revenues variance explanation above.
Purchased Power	12	14	1	
Other Electric Cost	31	34	3	
Total Cost of Sales	380	385	6	
Gross Margin:				
Electric Margin	460	427	34	Due to a combination of favorable weather and plant/system performance resulting in $22 million from favorable demand and energy revenue and production expenses, $3 million in ECR revenues and $3 million from the sale of excess generation. Margins also include net true-up adjustments of $6 million including KU's supply contracts with certain municipalities and the impact of the bonus depreciation extension.
Gas Margin	60	60	0	
Total Gross Margin	520	487	34	
Operating Expenses:				
O&M	184	189	5	Due to $2 million of labor and benefit savings, $1 million of lower outside services due to timing of consulting services and contract support, $1 million timing for maintenance changes and $1 million lower uncollectible accounts.
Depreciation & Amortization	88	89	2	
Taxes, Other than Income	13	14	1	
Total Operating Expenses	284	292	7	
Other income (expense)	(1)	(2)	1	
EBIT	235	193	43	
Interest Expense	42	44	1	
Income from Ongoing Operations before income taxes	193	149	44	
Income Tax Expense	76	56	(19)	Due to higher pre-tax income and certain effects of the bonus depreciation extension.
Net Income (loss) from ongoing operations	**$ 117**	**$ 93**	**$ 24**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 117	$ 93	$ 24	
KY Regulated Financing Costs	(8)	(8)	(0)	
KY Regulated Net Income	$ 109	$ 84	$ 24	
Earnings Per Share	$ 0.16	$ 0.13	$ 0.04	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — March 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ 8						$ 24
Energy Volumes (a)	2,656,202	2,643,548	12,654		$ (0.0)		8,796,948	8,393,796	403,151		$ 15.6	
Energy Prices (a)					$ 0.3						$ 0.3	
Customer Charges (Avg. Customers)	944,462	955,122	(10,660)		$ (0.0)		944,962	954,700	(9,738)		(0.1)	
Demand Charges (b)	44	36			$ 7.2		120	112			8.3	
ECR:						$ 6						$ 7
Average Rate Base	$ 1,793	$ 1,768	$ 24	10.27%	$ 0.2		$ 1,733	$ 1,709	$ 24	10.23%	$ 0.5	
Cost of Capital	10.37%	10.27%	0.10%	$ 1,793	$ 0.1		10.18%	10.23%	-0.05%	$ 1,733	(0.2)	
Jurisdictional Factor	89.81%	90.05%	-0.24%	$ 1,793	$ (0.0)		87.81%	88.81%	-1.00%	$ 1,733	(0.4)	
Other					$ 5.4						6.7	
DSM:						$ (0)						$ 1
Program Expense (Revenue Net of Expense)	$ 0.0	$ 0.0			$ (0.0)		$ 0.1	$ 0.1			$ (0.0)	
Lost Sales	$ 0.9	$ 1.1			$ (0.1)		3.9	3.2			$ 0.7	
Incentive	$ 0.0	$ 0.1			$ (0.0)		0.2	0.3			$ (0.1)	
Balancing Adjustment	$ (0.0)	$ -			$ (0.0)		0.0	-			$ 0.0	
Net Fuel Recovery	$ (0.1)	$ (0.3)				$ 0	$ (2.9)	$ (0.9)				$ (2)
Purchase Power Demand	$ (2.1)	$ (2.2)				$ 0	(5.8)	(6.6)				$ 1
Transmission	$ 0.7	$ 0.4				$ 0	3.1	2.2				$ 1
Other	$ (2.1)	$ (1.5)				$ (1)	(5.1)	(5.0)				$ (0)
Retail Margin Variance						$ 13						$ 31
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ 13						$ 34

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 42	871,170	$ 48.52	$ 43	878,986	$ 48.44	($0.3)	($0.4)	$0.1
Commercial	20	613,015	31.81	19	610,172	31.74	$0.1	$0.1	$0.0
Industrial	7	790,108	9.00	7	790,967	8.96	$0.0	($0.0)	$0.0
Municipals	1	151,575	5.84	1	149,902	5.22	$0.1	$0.0	$0.1
Other	5	230,334	23.84	5	213,521	24.06	$0.4	$0.3	$0.1
Native Load Total	**$ 75**	**2,656,202**	**$ 28.33**	**$ 75**	**2,643,548**	**$ 28.35**	**$0.3**	**($0.0)**	**$0.3**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 159	3,289,045	$ 48.34	$ 145	3,013,495	$ 48.27	$13.5	$12.9	$0.6
Commercial	61	1,936,382	31.75	60	1,888,689	32.01	$1.0	$1.5	($0.5)
Industrial	21	2,374,789	9.05	21	2,360,621	9.01	$0.2	$0.1	$0.1
Municipals	3	500,989	5.46	2	474,062	5.22	$0.3	$0.1	$0.1
Other	17	695,743	23.78	16	656,929	23.89	$0.8	$0.9	($0.0)
Native Load Total	**$ 261**	**8,796,948**	**$ 29.70**	**$ 245**	**8,393,796**	**$ 29.23**	**$15.9**	**$15.6**	**$0.3**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	12	12	1	37	36	1
Industrial	16	15	0	47	46	1
Municipals	10	5	6	21	15	6
Other	5	5	0	15	15	0
Native Load Total	**44**	**36**	**7**	**120**	**112**	**8**

Weather Statistics	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
Heating Degree Days - Louisville	601	35	6%	2,641	369	16%
Heating Degree Days - Lexington	649	29	5%	2,809	383	16%
Cooling Degree Days - Louisville	0	(8)	-100%	0	(8)	-100%
Cooling Degree Days - Lexington	0	(4)	-100%	0	(4)	-100%

Gas Gross Margin — March 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	$ 5	$ 5		$ 0	$ 15	$ 15		$ 0
Gas Supply Costs								
Gas Supply Costs	(18)	(21)	$ 3		(80)	(85)	$ 5	
GSC Revenue	18	21	(3)		80	85	(5)	
Net Gas Supply Costs				$ (0)				$ 0
Retail Gas (a)	10	10		$ (0)	47	42		$ 5
Wholesale Gas (a)	-	-		$ -	-	-		$ -
DSM	0	0		$ 0	0	0		$ 0
GLT	1	1		$ (0)	3	3		$ (0)
WNA	(4)	-		$ (4)	(6)	-		$ (6)
Other Margin	0	0		$ 0	1	0		$ 0
Gas Margin Variance				$ (3)				$ (0)

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 6	2,427,265	$ 2.64	$ 7	2,535,606	$ 2.64	($0.3)	($0.3)	($0.0)
Commercial	2	1,123,366	2.10	2	1,044,675	2.10	$0.2	$0.2	($0.0)
Industrial	0	137,067	2.09	0	125,939	1.86	$0.1	$0.0	$0.0
Public Authority	0	155,003	2.17	0	170,653	2.08	($0.0)	($0.0)	$0.0
Transportation	1	1,491,051	0.45	0	1,091,140	0.44	$0.2	$0.2	$0.0
Interdepartmental	0	55,611	5.66	0	27,926	15.61	($0.1)	$0.4	($0.6)
Ultimate Consumer	$ 10	5,389,363	$ 1.92	$ 10	4,995,938	$ 2.08	($0.0)	$0.5	($0.5)

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 30	11,440,496	$ 2.64	$ 27	10,244,629	$ 2.64	$3	$ 3	$ (0)
Commercial	11	5,023,355	2.09	9	4,356,983	2.10	$1	$ 1	$ (0)
Industrial	1	502,703	2.08	1	478,716	1.88	$0	$ 0	$ 0
Public Authority	2	774,729	2.08	1	714,996	2.07	$0	$ 0	$ 0
Transportation	2	4,447,190	0.49	2	3,900,983	0.44	$0	$0	$0
Interdepartmental	1	119,096	9.35	1	85,539	15.29	($0)	$1	($1)
Ultimate Consumer	$ 47	22,307,569	$ 2.09	$ 42	19,781,847	$ 2.10	$5	$5	($0)

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 24	$ 25	$ 1	$ (1)	$ 2	$ 1	$ (2)		$ 0
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	(0)	(0)		(0)	0		(0)
Energy Supply and Analysis	1	1	0	0		(0)	0		0
Generation Services	2	2	0	0		0	(0)		0
Electric Distribution	5	6	0	0		0	(0)	0	(0)
Gas Distribution	3	3	(0)	(0)		(0)	0	(0)	(0)
Safety and Security	0	0	0	0		(0)	0	0	0
Customer Services	7	7	0	0		0	0	(0)	(0)
Chief Operations Officer	**44**	**46**	**2**	**(1)**	**2**	**1**	**(1)**	**(0)**	**0**
General Counsel	3	3	(0)	0		(0)	0		0
Human Resources	1	1	0	0		(0)	(0)		(0)
General Counsel & HR	**3**	**3**	**0**	**0**		**(0)**	**0**		**0**
Information Technology	5	5	0	0		(0)	0		0
Supply Chain	0	0	0	0		(0)	0		0
Finance	2	2	(0)	0		0	0		(0)
Chief Financial Officer	**7**	**7**	**0**	**0**		**(0)**	**0**		**(0)**
Corporate	**16**	**15**	**(0)**	**(0)**		**(0)**	**(0)**	**(0)**	**1**
O&M Total MTD	**$ 70**	**$ 72**	**$ 2**	**$ (0)**	**$ 2**	**$ 1**	**$ (1)**	**$ (0)**	**$ 1**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 53	$ 52	$ (1)	$ (1)	$ 1	$ 1	$ (2)		$ 0
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	8	7	(1)	(0)		(1)	0		(0)
Energy Supply and Analysis	2	2	0	0		0	0		0
Generation Services	4	4	0	0		0	(0)		0
Electric Distribution	16	17	1	0		1	(0)	(0)	(0)
Gas Distribution	8	8	(1)	(0)		(0)	(0)	(0)	(0)
Safety and Security	1	1	0	0		(0)	0	0	(0)
Customer Services	20	22	2	0		1	0	1	(0)
Chief Operations Officer	**111**	**113**	**1**	**(1)**	**1**	**1**	**(2)**	**1**	**(0)**
General Counsel	7	7	0	0		0	0		(0)
Human Resources	2	2	0	0		0	0		0
General Counsel & HR	**9**	**9**	**0**	**0**		**0**	**0**		**0**
Information Technology	13	15	2	1		1	0		1
Supply Chain	1	1	0	0		0	0		0
Finance	5	5	(0)	(0)		(0)	0		(0)
Chief Financial Officer	**19**	**21**	**2**	**1**		**1**	**0**		**1**
Corporate	**44**	**46**	**1**	**1**		**(0)**	**(0)**	**(0)**	**1**
O&M Total MTD	**$ 184**	**$ 189**	**$ 5**	**$ 1**	**$ 1**	**$ 2**	**$ (2)**	**$ 1**	**$ 1**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 231	$ 225	$ (7)	$ (5)	$ 0	$ (3)	$ 0		$ 2
Project Engineering	1	1	(0)	(0)		(0)	(0)		0
Transmission	29	29	(0)	(0)		(1)	1		(0)
Energy Supply and Analysis	9	9	0	(0)		(0)	0		0
Generation Services	14	14	(0)	(0)		0	(0)		0
Electric Distribution	70	70	(0)	(0)		(0)	(0)	0	0
Gas Distribution	34	33	(0)	(0)		0	0	(0)	(0)
Safety and Security	4	4	(0)	(0)		0	0	0	0
Customer Services	86	87	0	0		(1)	1	0	0
Chief Operations Officer	**477**	**471**	**(7)**	**(5)**	**0**	**(5)**	**2**	**(0)**	**1**
General Counsel	33	33	0	0		0	0		0
Human Resources	7	7	(0)	(0)		(0)	0		(0)
General Counsel & HR	**40**	**40**	**(0)**	**(0)**		**(0)**	**0**		**(0)**
Information Technology	58	58	0	1		(1)	(0)		(0)
Supply Chain	4	4	0	0		0	0		0
Finance	20	20	(0)	0		0	0		(0)
Chief Financial Officer	**81**	**81**	**(0)**	**1**		**(1)**	**(0)**		**(0)**
Corporate	**169**	**176**	**7**	**5**		**2**	**(0)**	**(0)**	**(0)**
O&M Total YTD	**$ 767**	**$ 767**	**$ (0)**	**$ 0**	**$ 0**	**$ (4)**	**$ 2**	**$ (0)**	**$ 1**

Note: Schedules may not sum due to rounding.

Financing Activities — March 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance
PCB						
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	(0.0)	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.8**	**$ 1.1**	**$ 0.3**	**$ 2.6**	**$ 3.4**	**$ 0.9**
Rate	**1.07%**	**1.44%**	**0.38%**	**1.11%**	**1.49%**	**0.39%**
FMB/Sr Nts [(1)]						
Beg Bal	$ 3,643.0	$ 3,643.0	$ 0.0	$ 3,642.7	$ 3,642.7	$ -
End Bal	3,643.1	3,643.1	0.0	3,643.1	3,643.1	0.0
Ave Bal	**$ 3,643.0**	**$ 3,643.0**	**$ 0.0**	**$ 3,642.9**	**$ 3,642.9**	**$ 0.0**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ 0.0**	**$ 34.5**	**$ 34.5**	**$ -**
Rate	**3.66%**	**3.66%**	**0.00%**	**3.79%**	**3.79%**	**0.00%**
Short-term Debt						
Beg Bal	$ 686.5	$ 604.8	$ (81.7)	$ 615.4	$ 615.4	$ -
End Bal	524.0	608.1	84.1	524.0	608.1	84.1
Ave Bal	**$ 605.3**	**$ 606.4**	**$ 1.2**	**$ 569.7**	**$ 611.8**	**$ 42.0**
Interest Exp	**$ 0.4**	**$ 0.5**	**$ 0.1**	**$ 1.2**	**$ 1.6**	**$ 0.4**
Rate	**0.81%**	**1.01%**	**0.20%**	**0.84%**	**1.02%**	**0.18%**
Total End Bal	**$ 5,091.0**	**$ 5,175.1**	**$ 84.1**	**$ 5,091.0**	**$ 5,175.1**	**$ 84.1**
Total Average Bal	**$ 5,172.2**	**$ 5,173.4**	**$ 1.2**	**$ 5,136.5**	**$ 5,178.6**	**$ 42.0**
Total Expense Excl I/C [(2)]	**$ 14.1**	**$ 14.6**	**$ 0.5**	**$ 42.4**	**$ 43.6**	**$ 1.2**
Rate	**3.14%**	**3.27%**	**0.13%**	**3.30%**	**3.37%**	**0.06%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 115		$ 185
LG&E	500	216		284
KU	598	193	$ 198	207
TOTAL	$ 1,398	$ 524	$ 198	$ 676

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud
FFO to Debt - LG&E	10.6%	-0.20
FFO to Debt - KU	20.8%	-0.07
Debt to EBITDA - LG&E [(2)]	3.27	-0.22
Debt to EBITDA - KU [(2)]	3.65	-0.19
Debt to Capitalization - LG&E [(3)]	46.4%	-0.01
Debt to Capitalization - KU [(3)]	46.3%	-0.01

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet

March 2015

($ Millions)

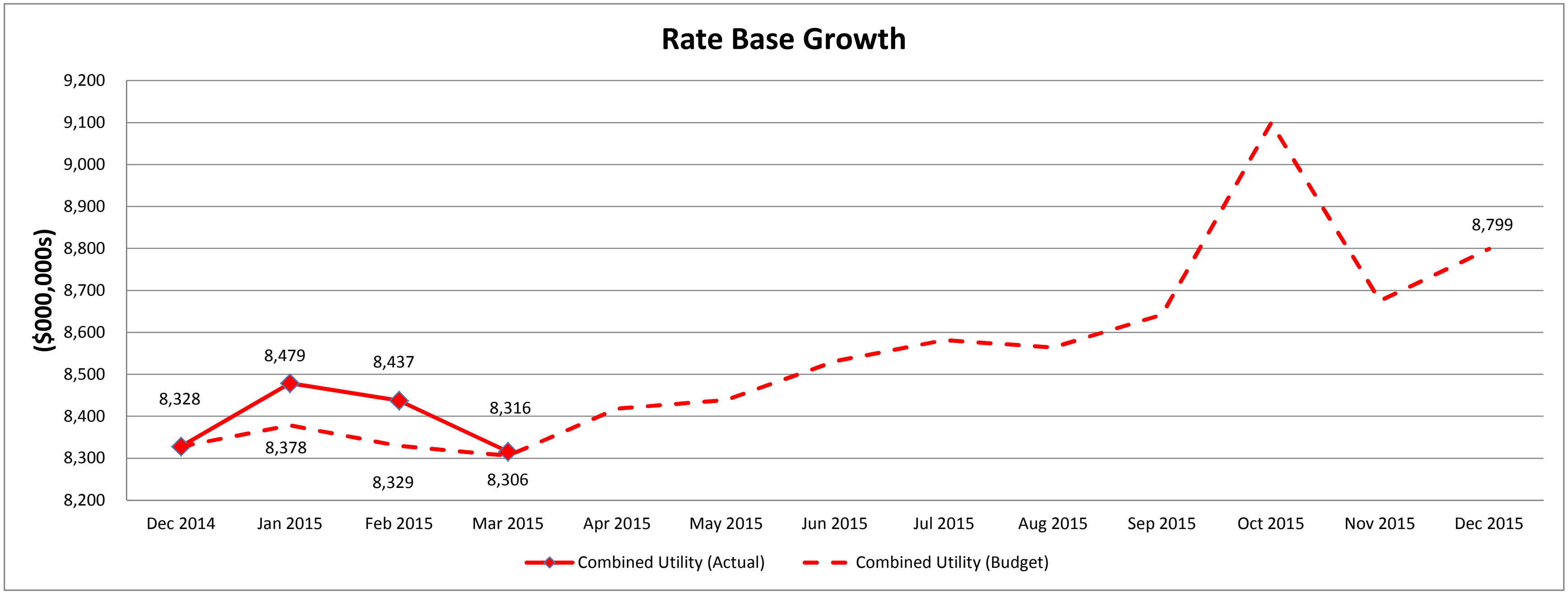
	3/31/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 40	$ (27)	$ 67	Budget assumed higher cash payments related to AP.
Accounts Receivable (Trade)	408	421	(13)	Lower accrued utility revenue ($32m) partially offset by higher customer accounts receivable $21m.
Inventory	239	258	(19)	Due to lower fuel purchases.
Deferred Income Taxes	21	16	5	
Regulatory Assets Current	20	32	(12)	Lower GSC ($11m) and FAC ($4m) balances partially offset by a higher ECR balance of $2m.
Prepayments and other current assets	39	177	(138)	Lower income tax receivable due to tax settlement from PPL ($134m).
Total Current Assets	767	876	(109)	
Property, Plant, and Equipment	10,696	10,707	(11)	Lower CWIP ($80m) and completed construction ($38m) offset by accumulated depreciation $107m.
Intangible Assets	161	161	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	719	662	57	Due to lower than expected interest rates on interest rate swaps.
Goodwill	997	997	-	
Other Long-term Assets	102	101	1	
Total Assets	**$ 13,443**	**$ 13,506**	**$ (63)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 353	$ 347	$ 6	
Accounts Payable - Affiliated Company	-	-	0	
Customer Deposits	52	52	0	
Derivative Liability	128	71	57	Due to lower than expected interest rates on interest rate swaps.
Accrued Taxes	25	188	(163)	Primarily due to the impact of the bonus depreciation extension.
Regulatory Liabilities Current	24	13	10	Higher DSM balance.
Other Current Liabilities	175	166	9	
Total Current Liabilities	756	837	(81)	
Debt - Affiliated Company	40	77	(36)	Lower dividends to PPL due to an offset resulting from an overpayment that occurred in December 2014.
Debt [(1)]	5,051	5,098	(48)	Due to cash inflow received in March 2015 used to offset normal drivers for commercial paper borrowings.
Total Debt	5,091	5,175	(84)	
Deferred Tax Liabilities	1,324	1,297	27	Primarily due to the impact of the bonus depreciation extension.
Investment Tax Credit	130	130	0	
Accum Provision for Pension & Related Benefits	256	259	(3)	
Asset Retirement Obligation	266	277	(11)	Due primarily to a reclass from noncurrent to current liability ($10M).
Regulatory Liabilities Non Current	961	962	(1)	
Derivative Liability	47	43	3	
Other Liabilities	270	269	2	
Total Deferred Credits and Other Liabilities	3,254	3,237	17	
Equity	4,342	4,257	85	
Total Liabilities and Equity	**$ 13,443**	**$ 13,506**	**$ (63)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

YTD	Actual	Budget	Variance	Comments
Net Income	117	93	24	Due to higher gross margin and lower O&M partially offset by higher taxes. See Income Statement.
Depreciation	101	101	(0)	
Deferred Income Taxes	75	53	21	Primarily due to the impact of the bonus depreciation extension.
Other Balance Sheet Movements	107	138	(30)	Primarily due to the impact of the bonus depreciation extension partially offset by tax settlement received from PPL.
Funds From Operations	**401**	**385**	**15**	
Changes in accounts receivables	(4)	(17)	13	Due to a combination of lower revenue and the effect of the accounts receivable curve for budgeted amounts versus actual.
Changes in inventories	72	53	19	Due to lower fuel purchases.
Change in Accounts Payable	(18)	(76)	58	Budget assumed lower accounts payable balances than actual and decrease in trade payables in Q1 2015 due to the winding down of construction projects at Trimble County, Mill Creek, and Ghent.
Change in Working Capital	**50**	**(39)**	**89**	
Operating Cash flow	**451**	**346**	**104**	
Capex	(321)	(302)	(19)	Due primarily to increased costs on environmental air projects at Mill Creek and timing of spend on environmental air projects at Brown, Trimble County, and Ghent.
Other Investing	4	0	4	
Loans to Affiliates	0	0	0	
Investing Cash flow	**(317)**	**(302)**	**(15)**	
Dividends	(23)	(54)	31	Lower dividends to PPL due to an offset resulting from an overpayment that occurred in December 2014.
Equity Infusion	0	(31)	31	Lower equity infusion due to cash inflow related to tax settlement with PPL.
Net Borrowings	(92)	(7)	(85)	See explanation for equity infusion above.
Other	0	0	0	
Financing Cash flow	**(115)**	**(92)**	**(23)**	
Net increase (decrease) in cash	**19**	**(48)**	**67**	



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Combined KU and LG&E ROE Mar 2015

KU and LG&E Combined

Reconciliation of Allowed Return to

2015 Regulatory Return and

Book ROE from Ongoing Operations (12 months ended March 2015)

Allowed Return [1]		10.28%	
Adjustments (net of tax):			
Change in capitalization - non ECR	-1.85%		Growth in non-ECR capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.25%		Additional borrowings offset by favorable rates
Change in margins	2.35%		Primarily new rates since last rate cases
Change in allowed expenses	-1.34%		Inflationary increases
		-1.08%	
Actual Regulated ROE		9.20%	

(1) Based on the most recent base rate filings with test years ending 3/31/12 KPSC, 12/31/13 FERC, 12/31/12 VA.

Performance Report

April 2015

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Kentucky Regulated Dashboard — April 2015

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.13	1.11	1.21	1.30	1.41	1.03
Employee lost-time incidents	0	0	0	2	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,322	2,400	11,593	11,232	36,488	34,582
Utility EFOR	5.9%	5.9%	3.6%	5.9%	N/A	5.9%
Utility EAF	60.4%	63.3%	79.8%	80.3%	N/A	83.8%
Steam Fleet Commercial Availability	94.5%	92.0%	96.2%	92.0%	N/A	92.0%
Combined SAIFI	0.12	0.08	0.33	0.31	N/A	1.19
Combined SAIDI (minutes)	9.57	6.72	27.04	27.75	N/A	106.60
GwH Sales						
Residential	589	693	3,878	3,706	11,118	10,842
Commercial	549	570	2,485	2,459	7,964	7,916
Industrial	804	767	3,179	3,128	10,038	10,024
Municipals	128	136	629	610	1,913	1,890
Other	215	200	911	857	2,761	2,723
Off-System Sales	5	2	188	150	281	311
Total	2,290	2,368	11,270	10,910	34,075	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.01%			
Commercial			-1.58%			
Industrial			2.01%			
Municipal			-1.00%			
Other			-0.34%			
Total			-0.52%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(1)]	3.6%	1.0%	9.8%	7.5%	9.0%	8.9%
Electric Margins	$119	$121	$580	$548	$1,776	$1,774
Gas Margins	14	12	73	72	166	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$4	$6	$11	$27	$45	$47
ECR	62	52	247	239	617	569
Generation	14	22	42	49	140	149
Transmission	5	7	17	20	63	60
Electric Distribution	13	16	45	45	161	162
Gas Distribution	7	7	21	20	86	83
Customer Services	1	1	4	4	19	17
IT and Other	3	4	10	12	38	38
Total	$108	$115	$398	$415	$1,170	$1,125
O&M ($ millions)[(2)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$47	$60	$159	$172	$477	$471
General Counsel & HR	2	3	11	12	40	40
Finance, IT, & Supply Chain	7	7	26	27	81	81
Burdens & Other Charges	13	14	57	60	169	176
Total	$69	$84	$253	$273	$767	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,497	3,591	3,497	3,591	3,546	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	3	7	6	N/A	9
NERC Possible Violations[(3)]	1	0	2	0	N/A	7

Variance Explanations

• Higher combined SAIFI and SAIDI due to greater amount of storms than expected.

• Current month lower GwH residential sales due to warmer than expected weather.

• YTD higher margins due to a combination of favorable weather and plant/system performance resulting in $19 million from favorable demand and energy revenue and production expenses, $6 million in ECR revenues and $3 million from the sale of excess generation. Margins also include net true-up adjustments of $6 million including KU's supply contracts with certain municipalities and the impact of the bonus depreciation extension.

• Current month lower O&M due to timing of $12 million in closure costs for the Cane Run steam units, $2 million due to timing for maintenance outages and $1 million lower labor and burden costs.

• YTD lower O&M due to timing of $12 million in closure costs for the Cane Run steam units, as costs budgeted for Q2 are now expected to be incurred in Q3, $3 million lower labor and burden costs, $3 million due to timing for maintenance outages, $1 million in uncollectible accounts and $1 million in material and consulting costs.

• Seven environmental events have occurred YTD. The events were a result of SO2, NOx, and CO exceedances at Mill Creek and Trimble County. All events were short timeframe limits which were exceeded and were all due to equipment malfunctions.

Major Developments

• LG&E and KU reached a unanimous settlement agreement with all of the parties in the base rate cases before the KPSC. Settlement discussions occurred on April 16-20, followed by the public evidentiary hearing on April 21. The agreement reflects a $125 million electric base rate increase for KU, and a $7 million gas base rate increase for LG&E. The proposed settlement does not establish a return on equity ("ROE") with respect to base rates; however, it does specify a 10 percent ROE to be utilized in LKE's environmental cost recovery and gas line tracker mechanisms. The agreed terms also include deferred cost recovery for a portion of pension and Green River costs. The settlement agreement remains subject to KPSC approval with a final order expected in the second quarter. If approved, the new rates will become effective July 1.

• Cane Run 7 continues to reach milestones in the commissioning process with both combustion turbines achieving full load operation. In addition, the steam turbine generator has been synchronized and has reached full load in a 1 on 1 configuration (only one combustion turbine in service to supply steam).

• The tie-in outages for the new wet flue gas desulfurization system and baghouses on Mill Creek units 1 and 2 have been completed as planned. In addition, the Ghent 1 baghouse tie-in outage was concluded ahead of schedule.

• LG&E and KU executed a four-year transportation agreement with Texas Gas for service related to the Bluegrass power purchase agreement. This represented the last condition precedent to the contract beginning on May 1. The agreement includes 165MWs of additional capacity from May 1, 2015 through April 30, 2019.

• The on-site portion of the SERC audit examining LKE's compliance with the NERC 693 Reliability Standards was completed in mid-April. SERC was complimentary of LKE's overall compliance culture, and indicated that there were no findings of any issues related to the audited requirements.

Significant Future Events

• The execution of LKE's construction plan continues in 2015. Cane Run 7 is expected to begin commercial operations during the second quarter. The Ghent 2, Trimble County 1 and Brown 3 fabric filter EPC contracts are underway as planned with tie-in outages projected for October. Site excavation work for the Brown Solar project has begun and the bid for the EPC contract will be issued in the second quarter.

(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issue for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget and Forecast (Month) — April 2015

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 198	$ 208	$ (11)	Due to lower energy volumes offset by lower fuel costs as shown below.
Gas Revenues	21	24	(3)	
Total Revenues	218	232	(14)	
Cost of Sales:				
Fuel Electric Costs	64	71	7	See Electric Revenues explanation above.
Gas Supply Expenses	7	12	5	Lower supply expense and gas volumes due to warmer than expected weather.
Purchased Power	5	5	1	
Other Electric Cost	10	11	1	
Total Cost of Sales	85	99	13	
Gross Margin:				
Electric Margin	119	121	(2)	
Gas Margin	14	12	2	
Total Gross Margin	133	133	(0)	
Operating Expenses:				
O&M	69	84	15	Lower due to timing of $12 million in closure costs for the Cane Run steam units, $2 million due to timing for maintenance outages and $1 million lower labor and burden costs.
Depreciation & Amortization	28	30	1	
Taxes, Other than Income	4	5	0	
Total Operating Expenses	102	118	16	
Other income (expense)	(1)	(1)	0	
EBIT	31	14	17	
Interest Expense	14	15	0	
Income from Ongoing Operations before income taxes	16	(1)	17	
Income Tax Expense	6	(1)	(7)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**10**	**(0)**	**$ 10**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 10	$ (0)	$ 10	
KY Regulated Financing Costs	(3)	(3)	-	
KY Regulated Net Income	$ 7	$ (3)	$ 10	
Earnings Per Share	$ 0.01	$ (0.00)	$ 0.02	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — April 2015

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 956	$ 933	$ 23	See Electric Margin variance explanation below.
Gas Revenues	162	170	(8)	See Gas Supply Expenses explanation below.
Total Revenues	1,118	1,104	14	
Cost of Sales:				
Fuel Electric Costs	319	322	2	
Gas Supply Expenses	88	98	10	Due to mapping difference for supply expense budgeted here but charged to gas supply revenue. These differences offset in Gas Margin as shown below.
Purchased Power	17	19	2	
Other Electric Cost	40	44	4	
Total Cost of Sales	465	484	19	
Gross Margin:				
Electric Margin	580	548	32	Due to a combination of favorable weather and plant/system performance resulting in $19 million from favorable demand and energy revenue and production expenses, $6 million in ECR revenues and $3 million from the sale of excess generation. Margins also include net true-up adjustments of $6 million including KU's supply contracts with certain municipalities and the impact of the bonus depreciation extension.
Gas Margin	73	72	2	
Total Gross Margin	653	620	33	
Operating Expenses:				
O&M	253	273	20	Lower due to timing of $12 million in closure costs for the Cane Run steam units, as costs budgeted for Q2 are now expected to be incurred in Q3, $3 million lower labor and burden costs, $3 million due to timing for maintenance outages, $1 million in uncollectible accounts and $1 million in material and consulting costs.
Depreciation & Amortization	116	119	3	
Taxes, Other than Income	18	18	1	
Total Operating Expenses	386	410	24	
Other income (expense)	(1)	(3)	2	
EBIT	266	207	60	
Interest Expense	57	58	2	
Income from Ongoing Operations before income taxes	210	148	61	
Income Tax Expense	83	56	(27)	Due to higher pre-tax income and certain effects of the bonus depreciation extension.
Net Income (loss) from ongoing operations	**$ 127**	**$ 93**	**$ 34**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 127	$ 93	$ 35	
KY Regulated Financing Costs	(11)	$ (11)	(0)	
KY Regulated Net Income	$ 116	$ 81	$ 35	
Earnings Per Share	$ 0.17	$ 0.12	$ 0.05	

Note: Schedules may not sum due to rounding.

Electric Gross Margin April 2015

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						$ (3)						$ 21
Energy Volumes (a)	2,284,389	2,365,507	(81,118)		$ (5.1)		11,081,337	10,759,304	322,033		$ 10.5	
Energy Prices (a)					$ (0.8)						$ (0.5)	
Customer Charges (Avg. Customers)	943,547	955,477	(11,930)		$ (0.0)		944,608	954,894	(10,286)		(0.1)	
Demand Charges (b)	39	36			$ 3.0		159	147			11.3	
ECR:						$ 2						$ 9
Average Rate Base	$ 1,850	$ 1,814	$ 36	10.15%	$ 0.3		$ 1,762	$ 1,736	$ 27	10.21%	$ 0.8	
Cost of Capital	10.40%	10.15%	0.25%	$ 1,850	$ 0.3		10.24%	10.21%	0.03%	$ 1,762	0.2	
Jurisdictional Factor	90.36%	90.44%	-0.08%	$ 1,850	$ (0.0)		88.48%	89.20%	-0.72%	$ 1,762	(0.4)	
Other					$ 1.6						8.3	
DSM:						$ 1						$ 1
Program Expense (Revenue Net of Expense)	$ 0.0	$ 0.0			$ (0.0)		$ 0.2	$ 0.2			$ (0.0)	
Lost Sales	$ 1.7	$ 1.1			$ 0.7		5.6	4.2			$ 1.4	
Incentive	$ 0.1	$ 0.1			$ (0.0)		0.3	0.3			$ (0.1)	
Balancing Adjustment	$ (0.0)	$ -			$ (0.0)		0.0	-			$ 0.0	
Net Fuel Recovery	$ (0.5)	$ (0.5)				$ 0	$ (3.4)	$ (1.4)				$ (2)
Purchase Power Demand	$ (2.7)	$ (2.2)				$ (1)	(8.5)	(8.8)				$ 0
Transmission	$ 0.2	$ 0.2				$ (0)	3.3	2.4				$ 1
Other	$ (2.6)	$ (1.2)				$ (1)	(7.7)	(6.2)				$ (1)
Retail Margin Variance						$ (2)						$ 29
Off-System Margin Variance						$ (0)						$ 3
Electric Margin Variance						$ (2)						$ 32

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

MTD	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 29	588,668	$ 48.94	$ 34	692,626	$ 48.83	($5.0)	($5.0)	$0.0
Commercial	16	549,093	29.98	18	569,715	31.07	($1.2)	($0.6)	($0.6)
Industrial	7	803,862	9.09	7	767,305	8.90	$0.5	$0.3	$0.2
Municipals	1	128,068	4.81	1	135,739	5.24	($0.1)	($0.0)	($0.1)
Other	5	214,699	22.52	5	200,123	24.20	($0.0)	$0.3	($0.3)
Native Load Total	**$ 58**	**2,284,389**	**$ 25.40**	**$ 64**	**2,365,507**	**$ 27.01**	**($5.9)**	**($5.1)**	**($0.8)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

YTD	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 188	3,877,713	$ 48.43	$ 179	3,706,120	$ 48.37	$8.5	$7.9	$0.6
Commercial	78	2,485,475	31.36	78	2,458,404	31.79	($0.2)	$0.9	($1.1)
Industrial	29	3,178,651	9.06	28	3,127,926	8.98	$0.7	$0.5	$0.2
Municipals	3	629,056	5.33	3	609,801	5.22	$0.2	$0.1	$0.1
Other	21	910,442	23.48	21	857,052	23.96	$0.8	$1.2	($0.3)
Native Load Total	**$ 319**	**11,081,337**	**$ 28.81**	**$ 309**	**10,759,304**	**$ 28.74**	**$10.0**	**$10.5**	**($0.5)**

(b) Demand Analysis (net of base ECR revenue):	MTD			YTD		
$mil	Act	Bud	Variance	Act	Bud	Variance
Commercial	13	12	1	50	48	2
Industrial	16	16	0	64	62	2
Municipals	4	3	0	25	18	6
Other	6	5	1	21	19	2
Native Load Total	**39**	**36**	**3**	**159**	**147**	**11**

Weather Statistics	MTD			YTD		
	Act	+/- Bud		Act	+/- Bud	
Heating Degree Days - Louisville	202	(38)	-16%	2,843	331	13%
Heating Degree Days - Lexington	260	(28)	-10%	3,069	355	13%
Cooling Degree Days - Louisville	21	(13)	-38%	21	(21)	-50%
Cooling Degree Days - Lexington	12	(10)	-45%	12	(14)	-54%

Gas Gross Margin — April 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ 0**	**$ 20**	**$ 20**		**$ 0**
Gas Supply Costs								
Gas Supply Costs	(7)	(11)	$ 5		(87)	(96)	10	
GSC Revenue	7	11	(4)		88	96	(9)	
Net Gas Supply Costs				**$ 1**				**$ 1**
Retail Gas (a)	**4**	**6**		**$ (1)**	**51**	**47**		**$ 4**
Wholesale Gas (a)	**-**	**-**		**$ -**	**-**	**-**		**$ -**
DSM	**0**	**0**		**$ 0**	**0**	**0**		**$ 0**
GLT	**1**	**1**		**$ (0)**	**3**	**4**		**$ (0)**
WNA	**2**	**-**		**$ 2**	**(3)**	**-**		**$ (3)**
Other Margin	**0**	**0**		**$ 0**	**1**	**1**		**$ 0**
Gas Margin Variance				**$ 2**				**$ 2**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 2	916,946	$ 2.64	$ 3	1,307,621	$ 2.64	($1.0)	($1.0)	($0.0)
Commercial	1	437,119	1.74	1	594,011	2.09	($0.5)	($0.3)	($0.2)
Industrial	0	70,994	1.49	0	90,143	1.81	($0.1)	($0.0)	($0.0)
Public Authority	0	69,687	1.34	0	97,997	2.06	($0.1)	($0.1)	($0.0)
Transportation	1	1,376,825	0.52	0	648,666	0.44	$0.4	$0.3	$0.1
Interdepartmental	0	19,756	16.01	0	331,927	1.36	($0.1)	($0.4)	$0.3
Ultimate Consumer	$ 4	2,891,327	$ 1.52	$ 6	3,070,365	$ 1.89	($1.4)	($1.6)	$0.2

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 33	12,357,442	$ 2.64	$ 31	11,552,250	$ 2.64	$2	$ 2	$ (0)
Commercial	11	5,460,474	2.07	10	4,950,994	2.10	$1	$ 1	$ (0)
Industrial	1	573,697	2.01	1	568,859	1.87	$0	$ 0	$ 0
Public Authority	2	844,416	2.02	2	812,993	2.07	$0	$ 0	$ (0)
Transportation	3	5,824,015	0.49	2	4,549,649	0.44	$1	$1	$0
Interdepartmental	1	138,852	10.30	2	417,466	4.21	($0)	($1)	$1
Ultimate Consumer	$ 51	25,198,896	$ 2.03	$ 47	22,852,212	$ 2.07	$4	$3	$1

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O&M — April 2015

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 27	$ 39	$ 12	$ 2	$ 2	$ (1)	$ 9		$ (0)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	0	(0)		0	0		(0)
Energy Supply and Analysis	1	1	0	0		0	0		(0)
Generation Services	1	1	0	0		0	(0)		(0)
Electric Distribution	6	6	(0)	(0)		(0)	(0)	0	(0)
Gas Distribution	3	3	0	0		0	0	0	(0)
Safety and Security	0	0	(0)	(0)		(0)	0	0	0
Customer Services	6	7	0	(0)		0	0	0	(0)
Chief Operations Officer	**47**	**60**	**12**	**2**	**2**	**(0)**	**9**	**0**	**(1)**
General Counsel	2	2	1	0		0	(0)		0
Human Resources	0	1	0	0		0	(0)		0
General Counsel & HR	**2**	**3**	**1**	**0**		**1**	**(0)**		**0**
Information Technology	5	5	(0)	0		(0)	0		(0)
Supply Chain	0	0	(0)	(0)		0	(0)		0
Finance	1	2	0	0		0	0		0
Chief Financial Officer	**7**	**7**	**0**	**0**		**(0)**	**0**		**0**
Corporate	**13**	**14**	**2**	**1**		**(0)**	**(0)**	**(0)**	**1**
O&M Total MTD	**$ 69**	**$ 84**	**$ 15**	**$ 3**	**$ 2**	**$ (0)**	**$ 9**	**$ 0**	**$ 1**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 80	$ 92	$ 12	$ 1	$ 3	$ 0	$ 7		$ (0)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	10	9	(1)	(0)		(1)	0		(0)
Energy Supply and Analysis	3	3	0	0		0	0		0
Generation Services	5	5	0	0		0	(0)		0
Electric Distribution	22	23	1	0		1	(0)	0	(0)
Gas Distribution	11	10	(1)	(0)		(0)	(0)	(0)	(0)
Safety and Security	1	2	0	0		(0)	0	0	(0)
Customer Services	26	29	3	0		1	0	1	(0)
Chief Operations Officer	**159**	**172**	**14**	**1**	**3**	**1**	**7**	**1**	**(1)**
General Counsel	9	10	1	0		0	(0)		0
Human Resources	2	2	0	0		0	0		0
General Counsel & HR	**11**	**12**	**1**	**0**		**1**	**(0)**		**0**
Information Technology	18	19	2	1		0	0		1
Supply Chain	1	1	0	(0)		0	0		0
Finance	6	7	0	0		(0)	0		0
Chief Financial Officer	**26**	**27**	**2**	**1**		**0**	**0**		**1**
Corporate	**57**	**60**	**3**	**2**		**(0)**	**(0)**	**(0)**	**2**
O&M Total MTD	**$ 253**	**$ 273**	**$ 20**	**$ 5**	**$ 3**	**$ 2**	**$ 7**	**$ 1**	**$ 2**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 231	$ 225	$ (7)	$ (5)	$ 0	$ (3)	$ 0		$ 2
Project Engineering	1	1	(0)	(0)		(0)	(0)		0
Transmission	29	29	(0)	(0)		(1)	1		(0)
Energy Supply and Analysis	9	9	0	(0)		(0)	0		0
Generation Services	14	14	(0)	(0)		0	(0)		0
Electric Distribution	70	70	(0)	(0)		(0)	(0)	0	0
Gas Distribution	34	33	(0)	(0)		0	0	(0)	(0)
Safety and Security	4	4	(0)	(0)		0	0	0	0
Customer Services	86	87	0	0		(1)	1	0	0
Chief Operations Officer	**477**	**471**	**(7)**	**(5)**	**0**	**(5)**	**2**	**(0)**	**1**
General Counsel	33	33	0	0		0	0		0
Human Resources	7	7	(0)	(0)		(0)	0		(0)
General Counsel & HR	**40**	**40**	**(0)**	**(0)**		**(0)**	**0**		**(0)**
Information Technology	58	58	0	1		(1)	(0)		(0)
Supply Chain	4	4	0	0		0	0		0
Finance	20	20	(0)	0		0	0		(0)
Chief Financial Officer	**81**	**81**	**(0)**	**1**		**(1)**	**(0)**		**(0)**
Corporate	**169**	**176**	**7**	**5**		**2**	**(0)**	**(0)**	**0**
O&M Total YTD	**$ 767**	**$ 767**	**$ (0)**	**$ 0**	**$ 0**	**$ (4)**	**$ 2**	**$ (0)**	**$ 1**

Note: Schedules may not sum due to rounding.

Financing Activities — April 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance
PCB						
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	(0.0)	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 3.4**	**$ 4.6**	**$ 1.2**
Rate	**1.10%**	**1.49%**	**0.39%**	**1.11%**	**1.49%**	**0.39%**
FMB/Sr Nts [(1)]						
Beg Bal	$ 3,643.1	$ 3,643.1	$ 0.0	$ 3,642.7	$ 3,642.7	$ -
End Bal	3,643.3	3,643.3	0.0	3,643.3	3,643.3	0.0
Ave Bal	**$ 3,643.2**	**$ 3,643.2**	**$ 0.0**	**$ 3,643.0**	**$ 3,643.0**	**$ 0.0**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ (0.0)**	**$ 46.0**	**$ 46.0**	**$ (0.0)**
Rate	**3.79%**	**3.79%**	**0.00%**	**3.79%**	**3.79%**	**0.00%**
Short-term Debt						
Beg Bal	$ 524.0	$ 608.1	$ 84.1	$ 615.4	$ 615.4	$ -
End Bal	482.8	707.0	224.1	482.8	707.0	224.1
Ave Bal	**$ 503.4**	**$ 657.5**	**$ 154.1**	**$ 549.1**	**$ 661.2**	**$ 112.1**
Interest Exp	**$ 0.4**	**$ 0.6**	**$ 0.2**	**$ 1.6**	**$ 2.1**	**$ 0.6**
Rate	**0.87%**	**1.02%**	**0.15%**	**0.86%**	**0.96%**	**0.11%**
Total End Bal	**$ 5,050.0**	**$ 5,274.2**	**$ 224.1**	**$ 5,050.0**	**$ 5,274.2**	**$ 224.1**
Total Average Bal	**$ 5,070.5**	**$ 5,224.6**	**$ 154.1**	**$ 5,116.0**	**$ 5,228.1**	**$ 112.1**
Total Expense Excl I/C [(2)]	**$ 14.3**	**$ 14.6**	**$ 0.3**	**$ 56.5**	**$ 58.2**	**$ 1.6**
Rate	**3.34%**	**3.35%**	**0.01%**	**3.32%**	**3.34%**	**0.02%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 125		$ 175
LG&E	500	208		292
KU	598	150	$ 198	250
TOTAL	$ 1,398	$ 483	$ 198	$ 717

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	15.3%	-0.15	24.4%	-0.08
FFO to Debt - KU	17.1%	-0.08	23.2%	+0.00
Debt to EBITDA - LG&E [(2)]	3.21	-0.28	3.64	+0.07
Debt to EBITDA - KU [(2)]	3.59	-0.25	3.58	-0.12
Debt to Capitalization - LG&E [(3)]	46.2%	-0.01	47.0%	+0.00
Debt to Capitalization - KU [(3)]	45.8%	-0.02	47.0%	-0.00

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

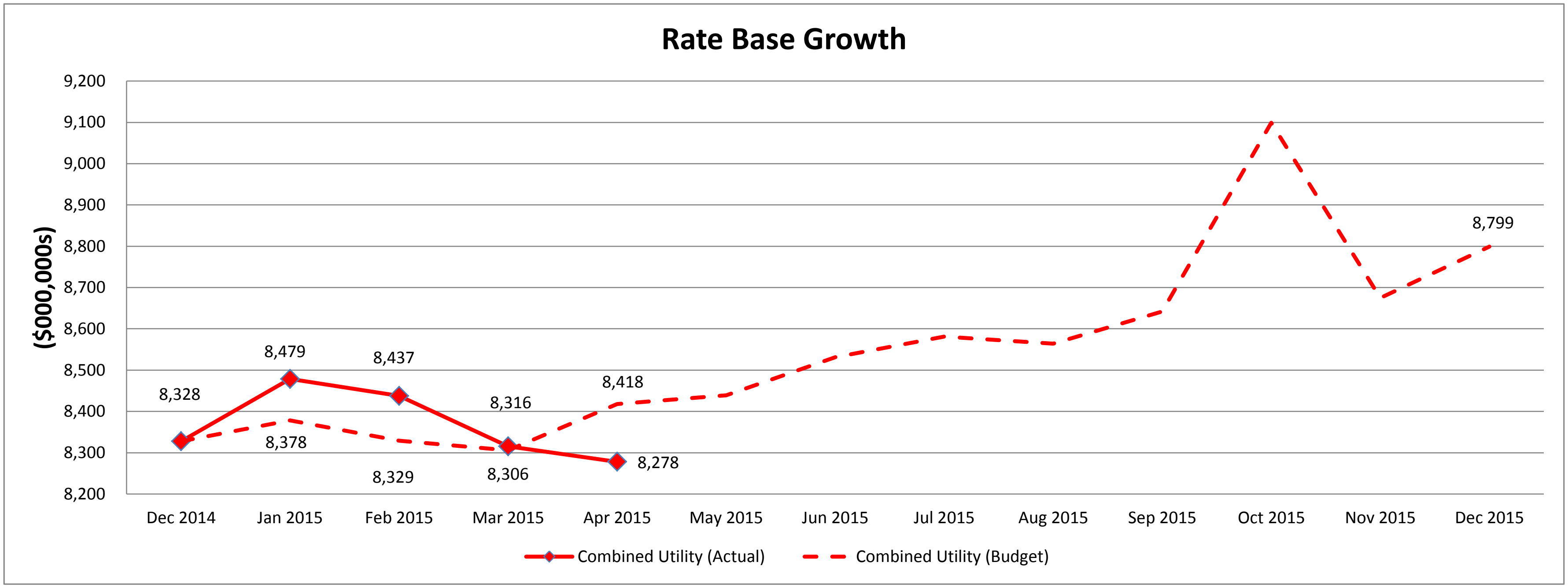
Balance Sheet

April 2015

($ Millions)

	4/30/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 15	$ (2)	
Accounts Receivable (Trade)	350	392	(42)	Lower accrued utility revenue ($45m) due to lower energy volumes partially offset by higher customer accounts receivable $6m.
Inventory	245	254	(9)	
Deferred Income Taxes	21	16	5	
Regulatory Assets Current	25	34	(9)	
Prepayments and other current assets	44	185	(142)	Primarily due to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	698	896	(198)	
Property, Plant, and Equipment	10,770	10,785	(15)	
Intangible Assets	157	157	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	696	662	34	
Goodwill	997	997	-	
Other Long-term Assets	104	102	2	
Total Assets	**$ 13,422**	**$ 13,599**	**$ (177)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 357	$ 345	$ 12	
Accounts Payable - Affiliated Company	-	-	0	
Customer Deposits	52	52	0	
Derivative Liability	108	71	37	Due to lower than expected interest rates on interest rate swaps.
Accrued Taxes	45	179	(134)	See explanation Prepayments and other current assets explanation above.
Regulatory Liabilities Current	24	13	11	Higher DSM balance.
Other Current Liabilities	182	176	6	
Total Current Liabilities	768	836	(67)	
Debt - Affiliated Company	50	67	(17)	Timing of cash needs from CEP Reserves.
Debt [(1)]	5,000	5,207	(207)	
Total Debt	5,050	5,274	(224)	
Deferred Tax Liabilities	1,324	1,297	27	
Investment Tax Credit	130	130	0	
Accum Provision for Pension & Related Benefits	257	260	(3)	
Asset Retirement Obligation	267	278	(12)	
Regulatory Liabilities Non Current	957	954	3	
Derivative Liability	45	43	2	
Other Liabilities	272	269	3	
Total Deferred Credits and Other Liabilities	3,251	3,232	19	
Equity	4,353	4,257	96	
Total Liabilities and Equity	**$ 13,422**	**$ 13,599**	**$ (177)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.



Attachment to Filing Requirement
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Performance Report

May 2015

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Kentucky Regulated Dashboard — May 2015

Safety	Current Month Actual	Current Month PY	YTD Actual	YTD PY	Full Year Forecast	Full Year PY
TCIR - Employees	0.53	0.55	1.04	1.11	1.41	1.03
Employee lost-time incidents	1	2	2	4	9	6

Reliability	Current Month Actual	Current Month Budget	YTD Actual	YTD Budget	Full Year Forecast	Full Year Budget
Generation Volumes	2,727	2,735	14,320	13,967	36,454	34,582
Utility EFOR	6.6%	5.9%	4.2%	5.9%	N/A	5.9%
Utility EAF	81.8%	89.6%	80.2%	82.2%	N/A	83.8%
Steam Fleet Commercial Availability	88.4%	92.0%	94.6%	92.0%	N/A	92.0%
Combined SAIFI	0.01	0.02	0.41	0.44	N/A	1.19
Combined SAIDI (minutes)	0.20	1.32	35.52	39.05	N/A	106.60
GwH Sales						
Residential	754	696	4,632	4,402	11,118	10,842
Commercial	634	656	3,119	3,115	7,964	7,916
Industrial	870	890	4,049	4,018	10,038	10,024
Municipals	148	144	777	754	1,913	1,890
Other	231	231	1,142	1,088	2,761	2,723
Off-System Sales	35	42	223	192	281	311
Total	2,672	2,659	13,942	13,569	34,075	33,706
Weather-Normalized Sales Growth			TTM			
Residential			-1.67%			
Commercial			-1.36%			
Industrial			2.21%			
Municipal			-1.21%			
Other			-0.38%			
Total			-0.31%			

Financial Metrics	Current Month Actual	Current Month Budget	YTD Actual	YTD Budget	Full Year Forecast	Full Year Budget
Utility ROE[(1)]	8.0%	6.0%	9.4%	7.2%	9.1%	8.9%
Electric Margins	$137	$130	$717	$678	$1,776	$1,774
Gas Margins	8	10	82	82	166	165

Capital Expenditures ($ millions)	Current Month Actual	Current Month Budget	YTD Actual	YTD Budget	Full Year Forecast	Full Year Budget
New Generation	$2	$2	$13	$29	$42	$47
ECR	49	45	296	283	617	569
Generation	8	14	50	63	141	149
Transmission	5	6	22	26	67	60
Electric Distribution	14	17	59	61	164	162
Gas Distribution	8	8	28	28	86	83
Customer Services	2	2	6	6	19	17
IT and Other	2	4	12	16	38	38
Total	$89	$97	$487	$512	$1,175	$1,125

O&M ($ millions)[(2)]	Current Month Actual	Current Month Budget	YTD Actual	YTD Budget	Full Year Forecast	Full Year Budget
Operations	$35	$37	$194	$209	$472	$471
General Counsel & HR	3	3	14	16	39	40
Finance, IT, & Supply Chain	6	6	32	34	81	81
Burdens & Other Charges	12	15	69	75	164	176
Total	$56	$61	$308	$333	$756	$767

Head Count	Current Month Actual	Current Month Budget	YTD Actual	YTD Budget	Full Year Forecast	Full Year Budget
Full-time Employees	3,498	3,567	3,498	3,567	3,543	3,566

Other Metrics	Current Month Actual	Current Month PY	YTD Actual	YTD PY	Full Year Forecast	Full Year PY
Environmental Events	2	0	9	6	N/A	9
NERC Possible Violations[(3)]	0	1	2	1	N/A	7

Variance Explanations

• Current month lower SAIDI due to favorable weather conditions.

• Current month higher margins of $3 million in retail electric volumes (primarily residential) due to favorable weather and $3 million in ECR margins.

• YTD higher margins due to a combination of favorable weather and plant/system performance resulting in $24 million from favorable demand and energy revenue and $3 million from the sale of excess generation. ECR margins up $12 million with spending levels ahead of budget year to date.

• YTD lower capital expenditures due primarily due to delayed timing of Cane Run 7 spending of $16 million and $13 million in timing changes for the Ohio Falls Redevelopment project to later this year and the Trimble County Ignite Fuel project shifting to 2016. That lower spending was partially offset by the expected increase in environmental capital expenditures of $13 million.

• Current month lower O&M due to $2 million in lower labor and burden costs, $2 million lower other materials and consulting costs and $1 million due to lower storm restoration costs.

• YTD lower O&M due to timing of $10 million in closure costs for the Cane Run steam units, $5 million lower labor and burden costs, $3 million due to timing for maintenance outages, $6 million in lower materials and consulting costs and $1 million in uncollectible accounts.

• Nine environmental events have occurred YTD. Eight of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, a sulfuric acid spill occurred during May at Ghent.

Major Developments

• A historic milestone occurred as Cane Run 7 began commercial operation on June 19th. This marks the end of a construction period that saw more than 600 construction employees working on the project at its peak; an incident rate of 0.37, which is 90 percent better than the average for construction companies; and zero lost time incidents. The 640 MW facility is the state's first natural gas combined-cycle plant.

• The FERC audit examining LKE's transmission formula rates was completed in late May. Total additional billings (revenue) as a result of the audit were offset by refunds identified by LKE, resulting in an unfavorable net impact of only $0.5 million.

• Kentucky's gubernatorial race delivered a thrilling primary as Republican Matt Bevin finished with a razor-thin 83-vote lead over Agriculture Commissioner James Comer. Comer requested a recanvass which confirmed the results. Bevin will face Jack Conway in November's general election which assures that for the first time in 60 years, Kentucky will elect a governor from Louisville. In the race for attorney general, Democrat Andy Beshear was unopposed in the primary, while Whitney Westerfield defeated Michael Hogan for the Republican nomination.

Significant Future Events

• A final order on the rate case is still expected by the end of June.

• The execution of LKE's construction plan continues in 2015. The Ghent 2, Trimble County 1 and Brown 3 fabric filter EPC contracts are underway as planned with tie-in outages projected for October. Site excavation work for the Brown Solar project has begun and bids for the EPC contract were due on June 18.

(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget and Forecast (Month) — May 2015

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 225	$ 222	$ 3	
Gas Revenues	13	17	(4)	
Total Revenues	238	240	(2)	
Cost of Sales:				
Fuel Electric Costs	73	74	1	
Gas Supply Expenses	5	7	3	
Purchased Power	4	5	0	
Other Electric Cost	10	14	3	
Total Cost of Sales	93	100	7	
Gross Margin:				
Electric Margin	137	130	8	Primarily due to $3 million in retail electric volumes (primarily residential) due to favorable weather and $3 million in ECR margins
Gas Margin	8	10	(2)	
Total Gross Margin	145	140	6	
Operating Expenses:				
O&M	56	61	5	Due to $2 million in lower labor and burden costs, $2 million lower other materials and consulting costs and $1 million due to lower storm restoration costs.
Depreciation & Amortization	28	30	1	
Taxes, Other than Income	4	5	0	
Total Operating Expenses	89	95	6	
Other income (expense)	(0)	(0)	(0)	
EBIT	57	44	13	
Interest Expense	14	15	1	
Income from Ongoing Operations before income taxes	42	30	13	
Income Tax Expense	16	11	(5)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**26**	**18**	**$ 8**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 26	$ 18	$ 8	
KY Regulated Financing Costs	(3)	(3)	-	
KY Regulated Net Income	$ 23	$ 16	$ 8	
Earnings Per Share	$ 0.03	$ 0.02	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — May 2015

($ Millions)

	YTD Actual	YTD Budget	YTD Variance	Comments
Revenues:				
Electric Revenues	$ 1,181	$ 1,156	$ 26	See Electric Margin variance explanation below.
Gas Revenues	175	187	(13)	See Gas Supply Expenses explanation below.
Total Revenues	1,356	1,343	13	
Cost of Sales:				
Fuel Electric Costs	393	396	3	
Gas Supply Expenses	93	106	13	Due to lower net purchases of $7 million and timing of pipeline demand charges of $5 million.
Purchased Power	21	24	3	
Other Electric Cost	50	58	8	Due to lower ECR expense of $4 million, scrubber reactant expense of $2 million and DSM expense of $2 million.
Total Cost of Sales	558	584	26	
Gross Margin:				
Electric Margin	717	678	39	Due to a combination of favorable weather and plant/system performance resulting in $24 million from favorable demand and energy revenue and $3 million from the sale of excess generation. ECR margins up $12 million with spending levels ahead of budget year to date.
Gas Margin	82	82	0	
Total Gross Margin	799	759	39	
Operating Expenses:				
O&M	308	333	25	Due to timing of $10 million in closure costs for the Cane Run steam units, $5 million lower labor and burden costs, $3 million due to timing for maintenance outages, $6 million in lower materials and consulting costs and $1 million in uncollectible accounts.
Depreciation & Amortization	144	149	4	
Taxes, Other than Income	22	23	1	
Total Operating Expenses	475	505	30	
Other income (expense)	(1)	(3)	2	
EBIT	323	251	72	
Interest Expense	71	73	2	
Income from Ongoing Operations before income taxes	252	178	74	
Income Tax Expense	99	67	(32)	Due to higher pre-tax income and certain effects of the bonus depreciation extension.
Net Income (loss) from ongoing operations	**154**	**111**	**$ 42**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 154	$ 111	$ 43	
KY Regulated Financing Costs	(14)	(14)	(0)	
KY Regulated Net Income	$ 139	$ 97	$ 42	
Earnings Per Share	$ 0.21	$ 0.14	$ 0.06	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — May 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ 2						$ 24
Energy Volumes (a)	2,635,976	2,616,993	18,983		$ 2.1		13,717,312	13,376,296	341,016		$ 12.5	
Energy Prices (a)					$ 0.6						$ 0.2	
Customer Charges (Avg. Customers)	943,691	955,936	(12,245)		$ (0.0)		944,425	955,103	(10,678)		(0.1)	
Demand Charges (b)	$ 41	$ 41			$ (0.2)		200	188			11.1	
ECR:						$ 3						$ 12
Average Rate Base	$ 1,875	$ 1,823	$ 52	10.04%	$ 0.4		$ 1,785	$ 1,753	$ 32	10.17%	$ 1.2	
Cost of Capital	10.43%	10.04%	0.39%	$ 1,875	$ 0.5		10.28%	10.17%	0.11%	$ 1,785	0.7	
Jurisdictional Factor	90.11%	90.12%	-0.01%	$ 1,875	$ (0.0)		88.83%	89.39%	-0.56%	$ 1,785	(0.4)	
Other					$ 2.1						10.4	
DSM:						$ 0						$ 2
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.0			$ 0.0		$ 0.2	$ 0.2			$ (0.0)	
Lost Sales	1.4	1.1			$ 0.4		7.1	5.3			$ 1.8	
Incentive	0.1	0.1			$ (0.0)		0.3	0.4			$ (0.1)	
Balancing Adjustment	0.0	-			$ 0.0		0.0	-			$ 0.0	
Net Fuel Recovery	$ 0.9	$ (0.3)				$ 1	$ (2.5)	$ (1.7)				$ (1)
Purchase Power Demand	(2.7)	(3.0)				$ 0	(11.2)	(11.8)				$ 1
Transmission	0.4	0.7				$ (0)	3.7	3.1				$ 1
Other	(0.8)	(1.3)				$ 0	(8.5)	(7.5)				$ (1)
Retail Margin Variance						$ 7						$ 37
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ 8						$ 39

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 37	754,207	$ 49.24	$ 34	695,525	$ 49.22	$2.9	$2.9	($0.0)
Commercial	19	633,528	30.07	20	656,035	29.86	($0.5)	($0.7)	$0.1
Industrial	8	869,520	9.03	8	890,204	8.88	($0.1)	($0.2)	$0.1
Municipals	1	147,914	5.56	1	144,232	5.21	$0.1	$0.0	$0.1
Other	5	230,807	23.11	5	230,997	21.94	$0.3	($0.0)	$0.3
Native Load Total	**$ 70**	**2,635,976**	**$ 26.63**	**$ 68**	**2,616,993**	**$ 25.81**	**$2.6**	**$2.1**	**$0.6**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 225	4,631,920	$ 48.56	$ 214	4,401,645	$ 48.51	$11.4	$10.8	$0.6
Commercial	97	3,119,003	31.10	98	3,114,439	31.38	($0.7)	$0.2	($0.9)
Industrial	37	4,048,171	9.06	36	4,018,130	8.96	$0.7	$0.3	$0.4
Municipals	4	776,970	5.37	4	754,034	5.22	$0.2	$0.1	$0.1
Other	27	1,141,248	23.41	26	1,088,048	23.53	$1.1	$1.1	($0.0)
Native Load Total	**$ 389**	**13,717,312**	**$ 28.39**	**$ 377**	**13,376,296**	**$ 28.17**	**$12.7**	**$12.5**	**$0.2**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	14	14	0	64	61	2
Industrial	16	16	(0)	80	78	2
Municipals	4	5	(1)	29	24	5
Other	6	5	1	27	25	2
Native Load Total	**41**	**41**	**(0)**	**200**	**188**	**11**

Weather - Avg. Hourly Temperature [1]	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	-	-	-	41	3	8%
(°F) Lexington Heating Season	-	-	-	39	3	9%
(°F) Louisville Cooling Season	70	4	5%	70	4	5%
(°F) Lexington Cooling Season	68	4	6%	68	4	6%

[1] Heating Season includes January through April and November and December. Cooling Season includes May through October.

Gas Gross Margin — May 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	$ 5	$ 5		$ 0	$ 25	$ 25		$ 0
Gas Supply Costs								
Gas Supply Costs	(4)	(7)	$ 3		(91)	(103)	12	
GSC Revenue	3	7	(3)		91	103	(12)	
Net Gas Supply Costs				$ (1)				$ 0
Retail Gas (a)	3	4		$ (1)	54	51		$ 3
Wholesale Gas (a)	-	-		$ -	-	-		$ -
DSM	0	0		$ 0	0	0		$ 0
GLT	1	1		$ 0	4	5		$ (0)
WNA	0	-		$ 0	(3)	-		$ (3)
Other Margin	0	0		$ (0)	1	1		$ 0
Gas Margin Variance				$ (2)				$ 0

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 1	465,983	$ 2.64	$ 2	731,122	$ 2.64	($0.7)	($0.7)	($0.0)
Commercial	1	264,400	1.93	1	368,103	2.09	($0.3)	($0.2)	($0.0)
Industrial	0	93,929	1.58	0	87,529	1.76	($0.0)	$0.0	($0.0)
Public Authority	0	26,881	1.79	0	62,136	2.03	($0.1)	($0.1)	($0.0)
Transportation	0	1,023,180	0.43	0	693,609	0.43	$0.1	$0.1	($0.0)
Interdepartmental	0	51,579	6.05	0	88,516	4.97	($0.1)	($0.2)	$0.1
Ultimate Consumer	$ 3	1,925,952	$ 1.39	$ 4	2,031,016	$ 1.83	($1.0)	($1.0)	($0.0)

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 34	12,823,425	$ 2.64	$ 32	12,283,372	$ 2.64	$1	$ 1	$ (0)
Commercial	12	5,724,874	2.06	11	5,319,097	2.09	$1	$ 1	$ (0)
Industrial	1	667,626	1.95	1	656,388	1.86	$0	$ 0	$ 0
Public Authority	2	871,297	2.01	2	875,130	2.06	($0)	$ (0)	$ (0)
Transportation	3	6,847,195	0.48	2	5,243,258	0.44	$1	$1	$0
Interdepartmental	2	190,431	9.15	2	505,982	4.35	($0)	($1)	$1
Ultimate Consumer	$ 54	27,124,848	$ 1.98	$ 51	24,883,227	$ 2.05	$3	$2	$1

O&M May 2015

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 17	$ (0)	$ (0)	$ 0	$ (2)	$ 1		$ 1
Project Engineering	0	0	(0)	(0)		(0)	(0)		0
Transmission	2	2	(0)	(0)		(0)	0		0
Energy Supply and Analysis	1	1	0	0		0	(0)		0
Generation Services	1	1	0	(0)		0	(0)		0
Electric Distribution	5	6	1	0		1	0	(0)	0
Gas Distribution	3	3	(0)	(0)		(0)	(0)	(0)	(0)
Safety and Security	0	0	(0)	0		(0)	(0)	0	0
Customer Services	6	6	1	0		0	0	0	0
Chief Operations Officer	**35**	**37**	**2**	**(0)**	**0**	**(1)**	**1**	**0**	**1**
General Counsel	2	3	1	0		0	0		0
Human Resources	0	1	0	0		0	(0)		0
General Counsel & HR	**3**	**3**	**1**	**0**		**0**	**0**		**0**
Information Technology	4	5	0	0		(0)	(0)		0
Supply Chain	0	0	0	0		0	0		(0)
Finance	1	1	0	0		0	0		0
Chief Financial Officer	**6**	**6**	**0**	**0**		**(0)**	**(0)**		**0**
Corporate	**12**	**15**	**2**	**1**		**(0)**	**(0)**	**(0)**	**1**
O&M Total MTD	**$ 56**	**$ 61**	**$ 5**	**$ 2**	**$ 0**	**$ (1)**	**$ 1**	**$ 0**	**$ 3**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 97	$ 108	$ 11	$ 1	4	$ (2)	$ 8		$ 1
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	12	11	(1)	(0)		(1)	0		(0)
Energy Supply and Analysis	4	4	0	0		0	0		0
Generation Services	6	6	0	0		0	(0)		0
Electric Distribution	27	29	2	0		2	(0)	0	(0)
Gas Distribution	14	13	(1)	(0)		(0)	(0)	(0)	(0)
Safety and Security	2	2	0	0		(0)	0	0	(0)
Customer Services	32	35	3	0		1	0	2	(0)
Chief Operations Officer	**194**	**209**	**15**	**1**	**4**	**0**	**8**	**2**	**1**
General Counsel	11	13	2	0		1	(0)		0
Human Resources	3	3	1	0		0	0		0
General Counsel & HR	**14**	**16**	**2**	**0**		**1**	**(0)**		**1**
Information Technology	22	24	2	1		(0)	(0)		1
Supply Chain	1	2	0	0		0	0		0
Finance	8	8	0	0		(0)	0		0
Chief Financial Officer	**32**	**34**	**2**	**1**		**(0)**	**0**		**1**
Corporate	**69**	**75**	**5**	**3**		**(0)**	**(0)**	**(0)**	**3**
O&M Total MTD	**$ 308**	**$ 333**	**$ 25**	**$ 6**	**$ 4**	**$ 1**	**$ 8**	**$ 1**	**$ 5**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 227	$ 225	$ (3)	$ (5)	$ 2	$ (6)	$ 1		$ 5
Project Engineering	1	1	0	0		(0)	(0)		0
Transmission	29	29	(0)	(0)		(1)	1		(0)
Energy Supply and Analysis	9	9	0	0		0	0		0
Generation Services	14	14	0	(0)		0	(0)		(0)
Electric Distribution	69	70	1	0		0	(0)	0	(0)
Gas Distribution	34	33	(0)	(0)		(0)	0	(0)	(0)
Safety and Security	4	4	0	0		0	0	0	(0)
Customer Services	86	87	1	0		(0)	1	0	0
Chief Operations Officer	**472**	**471**	**(2)**	**(4)**	**2**	**(6)**	**3**	**(0)**	**4**
General Counsel	32	33	0	0		0	0		(0)
Human Resources	7	7	0	0		0	0		(0)
General Counsel & HR	**39**	**40**	**1**	**0**		**1**	**0**		**(0)**
Information Technology	57	58	1	1		(1)	(0)		1
Supply Chain	4	4	0	0		0	0		0
Finance	20	20	(0)	0		(0)	0		(0)
Chief Financial Officer	**81**	**81**	**1**	**1**		**(1)**	**(0)**		**0**
Corporate	**164**	**176**	**12**	**10**		**(0)**	**(0)**	**(1)**	**3**
O&M Total YTD	**$ 756**	**$ 767**	**$ 11**	**$ 7**	**$ 2**	**$ (7)**	**$ 3**	**$ (1)**	**$ 7**

Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

Financing Activities — May 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance
PCB						
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	(0.0)	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 4.3**	**$ 5.7**	**$ 1.5**
Rate	**1.09%**	**1.44%**	**0.35%**	**1.10%**	**1.48%**	**0.38%**
FMB/Sr Nts (1)						
Beg Bal	$ 3,643.3	$ 3,643.3	$ 0.0	$ 3,642.7	$ 3,642.7	$ -
End Bal	3,643.4	3,643.4	0.0	3,643.4	3,643.4	0.0
Ave Bal	**$ 3,643.3**	**$ 3,643.3**	**$ 0.0**	**$ 3,643.0**	**$ 3,643.0**	**$ 0.0**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ (0.0)**	**$ 57.5**	**$ 57.5**	**$ (0.0)**
Rate	**3.66%**	**3.66%**	**0.00%**	**3.76%**	**3.76%**	**0.00%**
Short-term Debt						
Beg Bal	$ 482.8	$ 707.0	$ 224.1	$ 615.4	$ 615.4	$ -
End Bal	574.7	786.9	212.3	574.7	786.9	212.3
Ave Bal	**$ 528.8**	**$ 746.9**	**$ 218.2**	**$ 595.1**	**$ 701.2**	**$ 106.1**
Interest Exp	**$ 0.4**	**$ 0.6**	**$ 0.2**	**$ 1.9**	**$ 2.7**	**$ 0.8**
Rate	**0.82%**	**0.94%**	**0.12%**	**0.78%**	**0.93%**	**0.15%**
Total End Bal	**$ 5,142.0**	**$ 5,354.2**	**$ 212.3**	**$ 5,142.0**	**$ 5,354.2**	**$ 212.3**
Total Average Bal	**$ 5,096.0**	**$ 5,314.2**	**$ 218.2**	**$ 5,162.0**	**$ 5,268.1**	**$ 106.1**
Total Expense Excl I/C (2)	**$ 14.1**	**$ 14.7**	**$ 0.6**	**$ 70.6**	**$ 72.8**	**$ 2.2**
Rate	**3.22%**	**3.20%**	**-0.01%**	**3.26%**	**3.30%**	**0.03%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 136		$ 164
LG&E	500	246		254
KU	598	193	$ 198	207
TOTAL	$ 1,398	$ 575	$ 198	$ 625

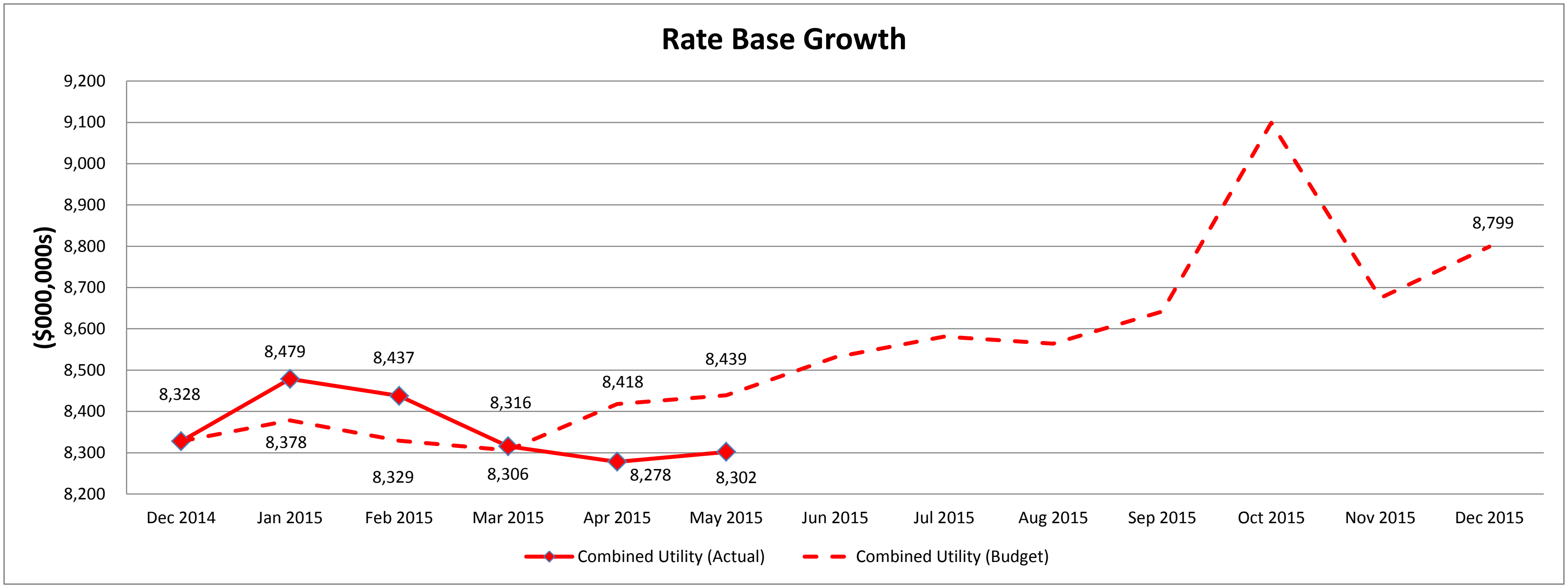
Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	17.1%	-0.13	26.2%	-0.06
FFO to Debt - KU	18.1%	-0.07	24.6%	+0.01
Debt to EBITDA - LG&E (2)	3.28	-0.21	3.62	+0.04
Debt to EBITDA - KU (2)	3.66	-0.18	3.55	-0.15
Debt to Capitalization - LG&E (3)	47.0%	-0.01	47.0%	+0.00
Debt to Capitalization - KU (3)	46.6%	-0.02	47.0%	-0.00

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet				**May 2015**
($ Millions)				
	5/31/2015	**YTD Budget**	**Variance**	**Comments**
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 14	$ 15	$ (1)	
Accounts Receivable (Trade)	351	402	(51)	Lower customer accounts receivable ($28m) and accrued utility revenue ($22m).
Inventory	248	252	(5)	
Deferred Income Taxes	21	16	5	
Regulatory Assets Current	25	30	(5)	
Prepayments and other current assets	45	183	(138)	Primarily due to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	704	899	(195)	
Property, Plant, and Equipment	10,826	10,846	(20)	
Intangible Assets	153	153	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	679	661	18	
Goodwill	997	997	-	
Other Long-term Assets	102	102	(0)	
Total Assets	**$ 13,462**	**$ 13,659**	**$ (198)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 327	$ 343	$ (16)	
Accounts Payable - Affiliated Company	86	-	86	Dividend payable $86m issued to PPL based on Q1 2015 net income.
Customer Deposits	52	52	0	
Derivative Liability	92	71	20	Due to lower than expected interest rates on interest rate swaps.
Accrued Taxes	65	195	(130)	See explanation Prepayments and other current assets explanation above.
Regulatory Liabilities Current	25	13	12	Higher balance due to less than expected spending on DSM programs.
Other Current Liabilities	132	126	6	
Total Current Liabilities	778	800	(22)	
Debt - Affiliated Company	61	79	(19)	Timing of cash needs from CEP Reserves.
Debt [(1)]	5,081	5,275	(194)	
Total Debt	5,142	5,354	(212)	
Deferred Tax Liabilities	1,324	1,297	27	
Investment Tax Credit	130	130	0	
Accum Provision for Pension & Related Benefits	261	261	(0)	
Asset Retirement Obligation	267	280	(12)	
Regulatory Liabilities Non Current	952	949	3	
Derivative Liability	44	43	1	
Other Liabilities	271	270	0	
Total Deferred Credits and Other Liabilities	3,249	3,229	19	
Equity	4,293	4,276	17	
Total Liabilities and Equity	**$ 13,462**	**$ 13,659**	**$ (198)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.



Note: Variance as of the current month primarily related to a lower balance in short-term borrowings due to more cash available as a result of tax related changes including bonus depreciation and also favorable sales margins year to date.

Performance Report

June 2015

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Kentucky Regulated Dashboard — June 2015

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees	1.17	0.00	1.06	0.94	1.41	1.03
Employee lost-time incidents	0	0	2	4	9	6
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,944	3,062	17,264	17,029	36,107	34,582
Utility EFOR	2.7%	5.9%	3.9%	5.9%	N/A	5.9%
Utility EAF	91.7%	92.6%	82.2%	83.9%	N/A	83.8%
Steam Fleet Commercial Availability	96.7%	92.0%	95.0%	92.0%	N/A	92.0%
Combined SAIFI	0.13	0.14	0.54	0.58	N/A	1.19
Combined SAIDI (minutes)	12.59	13.22	45.11	52.27	N/A	106.60
GwH Sales						
Residential	943	892	5,575	5,294	11,123	10,842
Commercial	700	737	3,819	3,852	7,883	7,916
Industrial	866	923	4,915	4,941	9,997	10,024
Municipals	167	167	944	921	1,910	1,890
Other	254	249	1,396	1,337	2,780	2,723
Off-System Sales	16	22	239	214	311	311
Total	2,946	2,990	16,888	16,559	34,003	33,706
Weather-Normalized Sales Growth			TTM			
Residential			-1.46%			
Commercial			-1.69%			
Industrial			2.14%			
Municipal			-1.10%			
Other			-0.78%			
Total			-0.37%			

	Current Month		YTD		Full Year	
Financial Metrics	Actual	Budget	Actual	Budget	Forecast	Budget
Utility ROE[1]	8.6%	8.8%	9.3%	7.4%	9.3%	8.9%
Electric Margins	$152	$147	$869	$825	$1,781	$1,774
Gas Margins	8	9	90	90	164	165
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
New Generation	($0)	$3	$13	$31	$29	$47
ECR	38	40	334	323	618	569
Generation	3	8	53	71	151	149
Transmission	7	5	29	31	68	60
Electric Distribution	15	19	74	80	165	162
Gas Distribution	7	9	36	37	87	83
Customer Services	2	2	8	7	19	17
IT and Other	3	4	15	19	38	38
Total	$74	$88	$561	$600	$1,175	$1,125
O&M ($ millions)[2]	Actual	Budget	Actual	Budget	Forecast	Budget
Operations	$45	$37	$239	$246	$471	$471
General Counsel & HR	3	4	17	19	39	40
Finance, IT, & Supply Chain	6	7	38	41	81	81
Burdens & Other Charges	12	14	81	89	159	176
Total	$67	$62	$375	$396	$750	$767
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,490	3,567	3,490	3,567	3,552	3,566
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	3	2	12	8	N/A	9
NERC Possible Violations[3]	3	2	5	3	N/A	7

Variance Explanations

• YTD higher margins due to a combination of favorable weather and plant/system performance resulting in $22 million from favorable demand and energy revenue and $3 million from the sale of excess generation. ECR margins up $15 million with higher spending levels and DSM margins up $2 million due to higher lost sales revenue.

• Current month lower capital expenditures of $14 million due primarily to milestone shifts for the environmental air project at Trimble County, a credit related to liquidated damages for Cane Run 7 and delays in landfill construction for phase 1B at the Ghent Landfill.

• YTD lower capital expenditures of $39 million due primarily to decreased spend and test energy budgeted but not used at Cane Run, timing changes for the Ohio Falls Redevelopment project to later this year and the Trimble County Ignite Fuel project shifting to 2016. That lower spending was partially offset by higher spend on air compliance projects at Mill Creek.

• YTD lower O&M due to $7 million of lower labor and benefit costs, $6 million in lower materials and outside services, $4 million due to the timing of maintenance outages, $3 million of lower uncollectible accounts and $1 million of lower storm restoration costs.

• Twelve environmental events have occurred YTD. Ten of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred during May at Ghent and a oil spill into the Ohio River at Mill Creek in June due to equipment failure.

Major Developments

• As part of the commissioning process for the new Cane Run 7 combined cycle unit, LG&E retired the remaining Cane Run 4 and 5 steam units in June. Cane Run 6 was retired in March of this year to help facilitate transmission work for the new plant.

• The KPSC issued final orders in the LG&E and KU rate cases, approving the unanimous settlement agreement reached in April. The new rates were put into effect July 1. In addition to the Kentucky rate cases, Old Dominion Power, KU's operational unit in Virginia, also filed a request with the Virginia State Corporation Commission for an increase of $7.2 million (approximately 10 percent) in its base rates. If approved, the new rates will become effective April 1, 2016.

• LKE was recently honored with multiple awards from external organizations covering a variety of disciplines. LKE's communication initiatives continue to flourish as LKE earned 16 awards in various categories at the 2015 Better Communications Competition, surpassing its own record and all other utilities for the most awards. Most notably, the Company was recognized with the prestigious "Communicator of the Year" award for the second year in a row. In addition to LKE's communication achievements, LKE has recently earned a top-10 finish in the medium-sized category of Benchmark Portal's annual Top 100 Call Center Contest. This marks the second time in three years LKE has earned the distinction.

• The month of June resulted in very stormy weather conditions in Kentucky which has continued into July with almost daily storm activity. The system and our team have responded well in maintaining and restoring service in a timely and safe manner. LKE avoided significant outage events or system damage, with only 60,000 weather related customer outages occurring during the month.

Significant Future Events

• The Virginia State Corporation Commission Staff is expected to be on-site in late July for the audit related to the rate case discovery. The audit is consistent with past practice and our anticipated timeline.

• The execution of LKE's construction plan continues in 2015. The Ghent 2, Trimble County 1 and Brown 3 fabric filter EPC contracts are progressing well with tie-in outages on schedule for October. Mill Creek 3 wet flue gas desulfurization system and fabric filter EPC work is also well underway for mid-2016 completion. Lastly, site excavation work for the Brown Solar project has begun and bids for the EPC contract are under evaluation.

[1] Excludes goodwill and other purchase accounting adjustments.
[2] Net of cost recovery mechanisms.
[3] The possible violation issues for YTD Actual is believed to be minimal risk.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

Income Statement: Actual vs. Budget and Forecast (Month) — June 2015

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q1 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 246	$ 253	$ (8)	Due to lower energy volumes offset by lower fuel costs as shown below.	$ 246	$ 246	$ (0)	
Gas Revenues	13	13	(0)		13	13	(1)	
Total Revenues	259	267	(8)		259	259	(1)	
Cost of Sales:								
Fuel Electric Costs	77	86	9	Primarily due to the timing related to the Cane Run 7 commission.	77	85	8	Primarily due to the timing related to the Cane Run 7 commission.
Gas Supply Expenses	5	4	(0)		5	5	0	
Purchased Power	4	6	2		4	5	1	
Other Electric Cost	12	14	2		12	14	2	
Total Cost of Sales	98	111	12		98	109	11	
Gross Margin:								
Electric Margin	152	147	5		152	142	10	See Fuel Electric Cost explanation above.
Gas Margin	8	9	(0)		8	9	(0)	
Total Gross Margin	160	156	4		160	150	10	
Operating Expenses:								
O&M	67	62	(4)		67	62	(4)	
Depreciation & Amortization	29	29	1		29	29	1	
Taxes, Other than Income	4	5	0		4	4	0	
Total Operating Expenses	100	96	(3)		100	96	(4)	
Other income (expense)	(0)	(1)	0		(0)	(0)	(0)	
EBIT	60	59	2		60	54	6	
Interest Expense	14	15	1		14	15	0	
Income from Ongoing Operations before income taxes	46	44	2		46	40	6	
Income Tax Expense	14	16	2		14	15	0	
Net Income (loss) from ongoing operations	**32**	**28**	**$ 4**		**$ 32**	**25**	**$ 7**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0		0	(0)	0	
Net Income (loss)	$ 23	$ 28	$ (5)		$ 23	$ 25	$ (1)	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 21	$ 25	$ (5)		$ 21	$ 22	$ (1)	
Earnings Per Share	$ 0.04	$ 0.04	$ 0.01		$ 0.04	$ 0.03	$ 0.02	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — June 2015

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,427	$ 1,409	$ 18	See Electric Margin variance explanation below.
Gas Revenues	188	200	(13)	See Gas Supply Expenses explanation below.
Total Revenues	1,615	1,610	5	
Cost of Sales:				
Fuel Electric Costs	470	482	12	Due to lower commodity costs primarily related to natural gas.
Gas Supply Expenses	98	110	13	Due to lower net purchases of $9 million and timing of pipeline demand charges of $5 million partially offset by less gas to storage activity of $3 million.
Purchased Power	26	30	4	
Other Electric Cost	62	72	10	Due to lower ECR expense of $5 million, scrubber reactant expense of $3 million and DSM expense of $2 million.
Total Cost of Sales	656	694	39	
Gross Margin:				
Electric Margin	869	825	44	Due to a combination of favorable weather and plant/system performance resulting in $22 million from favorable demand and energy revenue and $3 million from the sale of excess generation. ECR margins up $15 million with higher spending levels and DSM margins up $2 million due to higher lost sales revenue.
Gas Margin	90	90	(0)	
Total Gross Margin	959	915	44	
Operating Expenses:				
O&M	375	396	21	Due to $7 million of lower labor and benefit costs, $6 million in lower materials and outside services, $4 million due to the timing of maintenance outages, $3 million of lower uncollectible accounts and $1 million of lower storm restoration costs.
Depreciation & Amortization	173	178	5	Due to the timing of retirement and in service dates related to Cane Run units and other project completion updates.
Taxes, Other than Income	27	28	1	
Total Operating Expenses	575	601	27	
Other income (expense)	(1)	(4)	2	
EBIT	383	310	73	
Interest Expense	85	88	3	
Income from Ongoing Operations before income taxes	298	222	76	
Income Tax Expense	113	83	(30)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**185**	**139**	**$ 46**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 177	$ 139	$ 38	
KY Regulated Financing Costs	(17)	(17)	(0)	
KY Regulated Net Income	$ 160	$ 122	$ 38	
Earnings Per Share	$ 0.25	$ 0.18	$ 0.07	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget — June 2015

($ Millions)

	Full Year				Full Year			
	Q2 Forecast	Q1 Forecast	Variance	Comments	Q2 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,941	$ 2,954	$ (13)	Due to lower energy volumes driven by uncertainty in summer weather.	$ 2,941	$ 2,976	$ (36)	Due to lower energy volumes driven by uncertainty in summer weather partially offset by higher ECR revenue.
Gas Revenues	328	336	(8)	See Gas Supply Expense explanation below.	328	340	(12)	See Gas Supply Expense explanation below.
Total Revenues	3,269	3,290	(21)		3,269	3,317	(48)	
Cost of Sales:								
Fuel Electric Costs	960	976	16	Due to lower cost of fuel supply and lower projected energy volumes. See above.	960	980	20	Due to lower cost of fuel supply and lower projected energy volumes. See above.
Gas Supply Expenses	164	171	7	Due to lower GSC of $8 million.	164	175	11	Due to lower GSC of $14 million partially offset by higher GLT expense of $3 million.
Purchased Power	57	57	0		57	66	10	See Electric Revenues explanation above.
Other Electric Cost	143	152	9	Due to lower ECR expense of $7 million and scrubber reactant expense of $2 million.	143	156	13	Due to lower ECR expense of $7 million and scrubber reactant expense of $6 million.
Total Cost of Sales	1,323	1,356	32		1,323	1,377	54	
Gross Margin:								
Electric Margin	1,781	1,769	12	Primarily related to lower Other Electric Cost. See explanation above.	1,781	1,774	7	Primarily due to higher ECR revenue.
Gas Margin	164	165	(1)		164	165	(1)	
Total Gross Margin	1,945	1,934	11		1,945	1,939	6	
Operating Expenses:								
O&M	750	767	17	Primarily due to rate case settlement related savings of $14 million.	750	767	17	Primarily due to rate case settlement related savings of $14 million.
Depreciation & Amortization	350	351	1		350	356	6	Due to the timing of retirement and in service dates related to Cane Run units and other project completion updates.
Taxes, Other than Income	54	54	0		54	55	2	
Total Operating Expenses	1,154	1,172	18		1,154	1,179	25	
Other income (expense)	(4)	(3)	(1)		(4)	(6)	2	
EBIT	788	760	28		788	754	33	
Interest Expense	184	184	0		184	186	3	
Income from Ongoing Operations before income taxes	604	576	28		604	568	36	
Income Tax Expense	229	220	(9)	Due to higher pre-tax income.	229	215	(15)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**375**	**$ 355**	**$ 19**		**$ 375**	**$ 353**	**$ 21**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0		0	(0)	0	
Net Income (loss)	$ 367	$ 355	$ 11		$ 367	$ 353	$ 13	
KY Regulated Financing Costs	(33)	(33)	-		(33)	(33)	-	
KY Regulated Net Income	$ 333	$ 322	$ 11		$ 333	$ 320	$ 13	
Earnings Per Share	$ 0.49	$ 0.47	$ 0.02		$ 0.49	$ 0.47	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — June 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ (2)						$ 22
Energy Volumes (a)	2,929,456	2,968,963	(39,507)		$ 0.8		16,646,768	16,345,259	301,509		$ 13.3	
Energy Prices (a)					$ (0.5)						$ (0.3)	
Customer Charges (Avg. Customers)	943,961	956,362	(12,401)		$ (0.0)		944,347	955,313	(10,965)		(0.1)	
Demand Charges (b)	$ 43	$ 45			$ (1.9)		242	233			9.2	
ECR:						$ 3						$ 15
Average Rate Base	$ 1,898	$ 1,851	$ 47	10.23%	$ 0.4		$ 1,804	$ 1,769	$ 34	10.19%	$ 1.6	
Cost of Capital	10.46%	10.23%	0.23%	$ 1,898	$ 0.3		10.31%	10.19%	0.12%	$ 1,804	1.0	
Jurisdictional Factor	91.28%	91.62%	-0.34%	$ 1,898	$ (0.1)		89.28%	89.78%	-0.50%	$ 1,804	(0.5)	
Other					$ 2.2						12.7	
DSM:						$ 1						$ 2
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.3	$ 0.3			$ (0.0)	
Lost Sales	1.7	1.1			$ 0.7		8.8	6.3			$ 2.5	
Incentive	0.1	0.1			$ (0.0)		0.4	0.5			$ (0.1)	
Balancing Adjustment	(0.0)	-			$ (0.0)		0.0	-			$ 0.0	
Net Fuel Recovery	$ 0.1	$ (0.5)				$ 1	$ (2.4)	$ (2.1)				$ (0)
Purchase Power Demand	(2.8)	(3.1)				$ 0	(14.0)	(14.8)				$ 1
Transmission	1.3	0.7				$ 1	5.1	3.8				$ 1
Other	(0.1)	(1.4)				$ 1	(8.6)	(8.9)				$ 0
Retail Margin Variance						$ 5						$ 41
Off-System Margin Variance						$ (0)						$ 3
Electric Margin Variance						$ 5						$ 44

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 46	942,750	$ 49.22	$ 44	892,376	$ 49.25	$2.5	$2.6	($0.1)
Commercial	21	699,864	30.12	22	737,222	30.40	($1.3)	($1.1)	($0.2)
Industrial	8	865,894	9.06	8	922,789	8.95	($0.4)	($0.5)	$0.1
Municipals	1	167,428	4.98	1	167,094	5.22	($0.0)	$0.0	($0.0)
Other	5	253,520	21.53	6	249,481	23.29	($0.4)	($0.1)	($0.3)
Native Load Total	**$ 82**	**2,929,456**	**$ 27.86**	**$ 81**	**2,968,963**	**$ 27.38**	**$0.3**	**$0.8**	**($0.5)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 271	5,574,670	$ 48.67	$ 257	5,294,021	$ 48.63	$13.9	$13.4	$0.5
Commercial	118	3,818,866	30.92	120	3,851,662	31.20	($2.1)	($1.0)	($1.1)
Industrial	45	4,914,065	9.06	44	4,940,920	8.96	$0.2	($0.2)	$0.5
Municipals	5	944,399	5.30	5	921,127	5.22	$0.2	$0.1	$0.1
Other	32	1,394,768	23.06	31	1,337,529	23.49	$0.8	$1.0	($0.3)
Native Load Total	**$ 471**	**16,646,768**	**$ 28.30**	**$ 458**	**16,345,259**	**$ 28.03**	**$13.0**	**$13.3**	**($0.3)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	15	15	(1)	78	77	2
Industrial	17	17	(1)	97	96	1
Municipals	5	6	(1)	34	30	4
Other	6	6	0	33	31	2
Native Load Total	**43**	**45**	**(2)**	**242**	**233**	**9**

Weather - Avg. Hourly Temperature [1]	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	-	-	-	41	3	8%
(°F) Lexington Heating Season	-	-	-	39	3	9%
(°F) Louisville Cooling Season	76	1	1%	73	3	4%
(°F) Lexington Cooling Season	73	1	1%	71	2	3%

[1] Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — June 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ 0**	**$ 30**	**$ 30**		**$ 0**
Gas Supply Costs								
Gas Supply Costs	(3)	(4)	$ 1		(94)	(107)	13	
GSC Revenue	3	4	(1)		94	107	(13)	
Net Gas Supply Costs				**$ (0)**				**$ 0**
Retail Gas (a)	**2**	**3**		**$ (0)**	**56**	**54**		**$ 2**
Wholesale Gas (a)	**-**	**-**		**$ -**	**-**	**-**		**$ -**
DSM	**0**	**0**		**$ 0**	**0**	**0**		**$ 0**
GLT	**1**	**1**		**$ 0**	**5**	**6**		**$ (0)**
WNA	**(0)**	**-**		**$ (0)**	**(3)**	**-**		**$ (3)**
Other Margin	**0**	**0**		**$ (0)**	**1**	**1**		**$ 0**
Gas Margin Variance				**$ (0)**				**$ (0)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 1	379,481	$ 2.64	$ 1	425,087	$ 2.64	($0.1)	($0.1)	($0.0)
Commercial	1	267,735	1.93	1	260,712	2.09	($0.0)	$0.0	($0.0)
Industrial	0	146,660	1.06	0	87,599	1.74	$0.0	$0.1	($0.1)
Public Authority	0	28,888	1.77	0	44,815	2.02	($0.0)	($0.0)	($0.0)
Transportation	0	836,727	0.21	0	694,682	0.43	($0.1)	$0.1	($0.2)
Interdepartmental	0	48,763	6.18	0	199,681	2.22	($0.1)	($0.3)	$0.2
Ultimate Consumer	$ 2	1,708,254	$ 1.29	$ 3	1,712,576	$ 1.55	($0.5)	($0.3)	($0.1)

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 35	13,202,906	$ 2.64	$ 34	12,708,459	$ 2.64	$1	$ 1	$ (0)
Commercial	12	5,992,609	2.05	12	5,579,808	2.09	$1	$ 1	$ (0)
Industrial	1	814,286	1.79	1	743,987	1.84	$0	$ 0	$ (0)
Public Authority	2	900,185	2.00	2	919,945	2.06	($0)	$ (0)	$ (0)
Transportation	3	7,683,922	0.45	3	5,937,940	0.44	$1	$1	$0
Interdepartmental	2	239,194	8.54	3	705,664	3.75	($1)	($2)	$1
Ultimate Consumer	$ 56	28,833,102	$ 1.94	$ 54	26,595,803	$ 2.02	$2	$1	$1

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 24	$ 15	$ (9)	$ (3)	$ 1	$ 0	$ (6)		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	3	3	0	(0)		(0)	0		0
Energy Supply and Analysis	1	1	0	0		(0)	0		0
Generation Services	1	1	0	(0)		0	(0)		0
Electric Distribution	6	6	0	(0)		0	(0)	(0)	0
Gas Distribution	3	3	(0)	0		0	(0)	(0)	(0)
Safety and Security	0	0	0	(0)		0	0	0	0
Customer Services	7	8	1	(0)		0	0	1	(0)
Chief Operations Officer	**45**	**37**	**(8)**	**(3)**	**1**	**1**	**(6)**	**1**	**(1)**
General Counsel	3	3	0	0		0	0		(0)
Human Resources	1	1	0	0		0	(0)		0
General Counsel & HR	**3**	**4**	**0**	**0**		**0**	**(0)**		**(0)**
Information Technology	4	5	0	0		0	0		0
Supply Chain	0	0	(0)	(0)		0	0		(0)
Finance	2	2	0	0		(0)	0		0
Chief Financial Officer	**6**	**7**	**0**	**0**		**0**	**0**		**0**
Corporate	**12**	**14**	**2**	**2**		**(0)**	**(0)**	**1**	**0**
O&M Total MTD	**$ 67**	**$ 62**	**$ (4)**	**$ (1)**	**$ 1**	**$ 1**	**$ (6)**	**$ 2**	**$ (1)**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 121	$ 124	$ 2	$ (1)	4	$ 1	$ 1		$ (3)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	15	14	(1)	(0)		(1)	1		(0)
Energy Supply and Analysis	4	4	0	0		0	0		0
Generation Services	7	7	0	0		0	(0)		0
Electric Distribution	33	35	2	0		2	(0)	0	(0)
Gas Distribution	17	16	(1)	(0)		(0)	(0)	(0)	(0)
Safety and Security	2	2	0	0		(0)	0	0	(0)
Customer Services	39	43	4	0		1	0	3	(1)
Chief Operations Officer	**239**	**246**	**8**	**(0)**	**4**	**3**	**2**	**3**	**(4)**
General Counsel	14	16	2	0		1	(0)		0
Human Resources	3	4	1	0		0	(0)		0
General Counsel & HR	**17**	**19**	**3**	**1**		**1**	**(0)**		**1**
Information Technology	27	29	2	1		(0)	0		1
Supply Chain	2	2	0	(0)		0	0		0
Finance	10	10	0	0		(0)	0		0
Chief Financial Officer	**38**	**41**	**3**	**1**		**(0)**	**0**		**1**
Corporate	**81**	**89**	**8**	**5**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 375**	**$ 396**	**$ 21**	**$ 6**	**$ 4**	**$ 4**	**$ 2**	**$ 3**	**$ 1**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 226	$ 225	$ (2)	$ (2)	$ 3	$ (7)	$ (0)		$ 3
Project Engineering	1	1	0	0		(0)	(0)		0
Transmission	29	29	(0)	(0)		(1)	1		(0)
Energy Supply and Analysis	9	9	0	0		(0)	0		0
Generation Services	14	14	0	(0)		0	(0)		(0)
Electric Distribution	69	70	1	0		0	(0)	0	0
Gas Distribution	34	33	(1)	(0)		(0)	0	(0)	(0)
Safety and Security	4	4	0	0		0	0	0	(0)
Customer Services	86	87	1	1		(0)	1	0	(0)
Chief Operations Officer	**471**	**471**	**(1)**	**(1)**	**3**	**(7)**	**2**	**(0)**	**2**
General Counsel	32	33	0	0		0	0		(0)
Human Resources	7	7	0	0		0	0		(0)
General Counsel & HR	**39**	**40**	**1**	**0**		**1**	**0**		**(0)**
Information Technology	57	58	1	1		(1)	(0)		1
Supply Chain	4	4	0	0		0	0		0
Finance	20	20	(0)	0		(0)	0		(0)
Chief Financial Officer	**81**	**81**	**1**	**1**		**(1)**	**(0)**		**0**
Corporate	**159**	**176**	**17**	**14**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 750**	**$ 767**	**$ 17**	**$ 14**	**$ 3**	**$ (8)**	**$ 1**	**$ 0**	**$ 6**

Note: Schedules may not sum due to rounding.

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Financing Activities — June 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	(0.0)	923.9	923.9	(0.0)	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 5.1**	**$ 6.9**	**$ 1.7**	**$ 11.7**	**$ 13.8**	**$ 2.0**
Rate	**1.13%**	**1.49%**	**0.36%**	**1.11%**	**1.48%**	**0.38%**	**1.27%**	**1.49%**	**0.22%**
FMB/Sr Nts [(1)]									
Beg Bal	$ 3,643.4	$ 3,643.4	$ 0.0	$ 3,642.7	$ 3,642.7	$ -	$ 3,642.7	$ 3,642.7	$ -
End Bal	3,643.6	3,643.6	0.0	3,643.6	3,643.6	0.0	3,794.4	3,794.4	0.0
Ave Bal	**$ 3,643.5**	**$ 3,643.5**	**$ 0.0**	**$ 3,643.1**	**$ 3,643.1**	**$ 0.0**	**$ 3,756.1**	**$ 3,756.1**	**$ -**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ 0.0**	**$ 69.0**	**$ 69.0**	**$ -**	**$ 148.1**	**$ 148.3**	**$ 0.2**
Rate	**3.79%**	**3.79%**	**0.00%**	**3.76%**	**3.76%**	**0.00%**	**3.94%**	**3.95%**	**0.01%**
Short-term Debt									
Beg Bal	$ 574.7	$ 786.9	$ 212.3	$ 615.4	$ 615.4	$ -	$ 615.4	$ 615.4	$ -
End Bal	620.1	701.2	81.1	620.1	701.2	81.1	670.4	662.0	(8.4)
Ave Bal	**$ 597.4**	**$ 744.0**	**$ 146.7**	**$ 617.8**	**$ 658.3**	**$ 40.5**	**$ 600.1**	**$ 633.9**	**$ 33.8**
Interest Exp	**$ 0.4**	**$ 0.6**	**$ 0.2**	**$ 2.3**	**$ 3.3**	**$ 1.0**	**$ 4.4**	**$ 6.0**	**$ 1.7**
Rate	**0.72%**	**0.97%**	**0.25%**	**0.74%**	**1.01%**	**0.27%**	**0.73%**	**0.95%**	**0.23%**
Total End Bal	**$ 5,187.5**	**$ 5,268.6**	**$ 81.1**	**$ 5,187.5**	**$ 5,268.6**	**$ 81.1**	**$ 5,388.7**	**$ 5,380.2**	**$ (8.5)**
Total Average Bal	**$ 5,164.8**	**$ 5,311.4**	**$ 146.7**	**$ 5,184.8**	**$ 5,225.3**	**$ 40.5**	**$ 5,280.1**	**$ 5,314.0**	**$ 33.8**
Total Expense Excl I/C [(2)]	**$ 14.2**	**$ 14.7**	**$ 0.5**	**$ 84.8**	**$ 87.5**	**$ 2.7**	**$ 183.6**	**$ 186.3**	**$ 2.7**
Rate	**3.29%**	**3.31%**	**0.02%**	**3.25%**	**3.33%**	**0.08%**	**3.48%**	**3.51%**	**0.03%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 134		$ 166
LG&E	500	259		241
KU	598	227	$ 198	173
TOTAL	$ 1,398	$ 620	$ 198	$ 580

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	34.4%	2%	27.2%	-5%
FFO to Debt - KU	27.2%	3%	23.8%	1%
Debt to EBITDA - LG&E [(2)]	3.37	-0.12	3.56	-0.02
Debt to EBITDA - KU [(2)]	3.71	-0.13	3.56	-0.14
Debt to Capitalization - LG&E [(3)]	46.8%	0%	47.0%	0%
Debt to Capitalization - KU [(3)]	46.8%	0%	47.0%	0%

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

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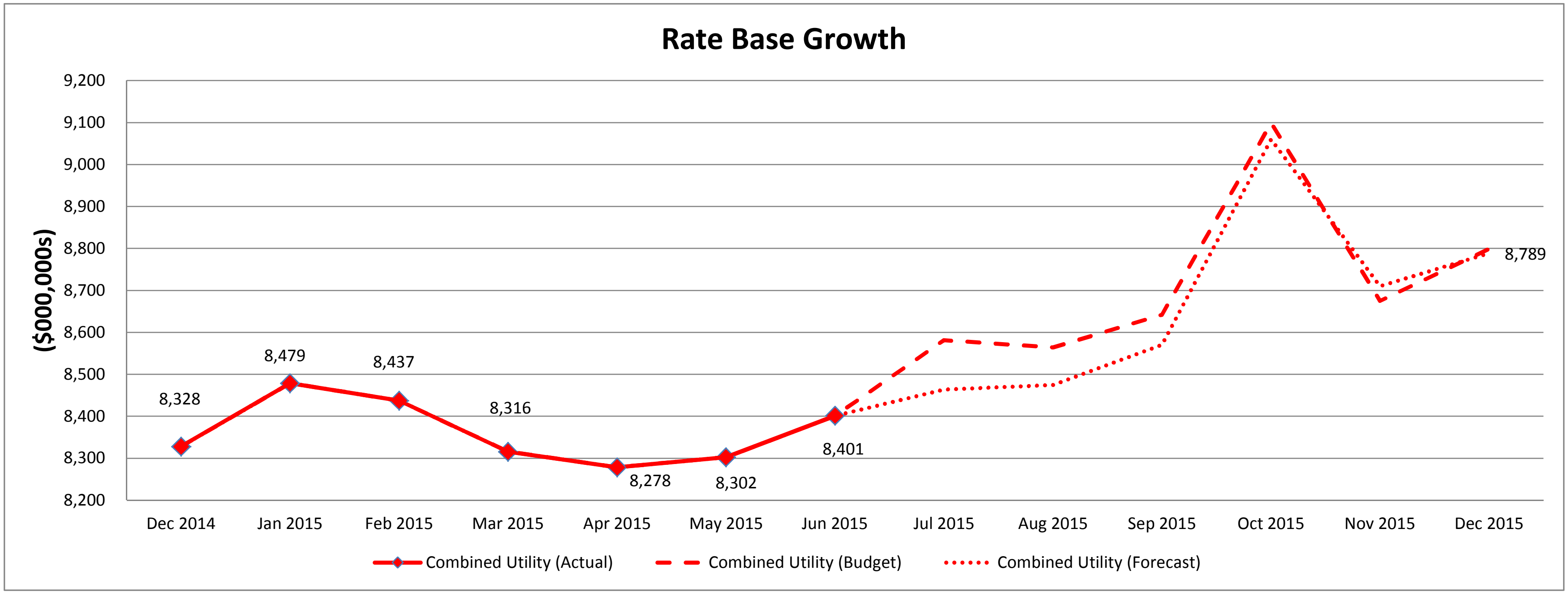
Balance Sheet — June 2015

($ Millions)

	6/30/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 16	$ (2)	
Accounts Receivable (Trade)	378	418	(40)	Lower customer accounts receivable ($29m) and accrued utility revenue ($12m).
Inventory	249	256	(6)	
Deferred Income Taxes	42	16	26	Due to NOL utilization during the 1st half of 2016 of $20m and an intercompany transfer related to allocations from PPL of $5m.
Regulatory Assets Current	24	32	(8)	
Prepayments and other current assets	49	181	(132)	Primarily due to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	756	919	(163)	
Property, Plant, and Equipment	11,033	10,899	134	
Intangible Assets	148	149	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	623	661	(38)	
Goodwill	997	997	0	
Other Long-term Assets	90	103	(13)	Primarily due to return of collateral as a result of update of credit rating from S&P ($12m).
Total Assets	**$ 13,648**	**$ 13,728**	**$ (80)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 353	$ 350	$ 4	Due to reclassification of retainage related to CR7 project from long-term to short-term of $38m partially offset by change in budgeted Accounts Payable for timing of payments ($42m).
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	52	52	(0)	
Derivative Liability	50	71	(21)	Due to higher than expected interest rates on interest rate swaps.
Accrued Taxes	59	195	(137)	See Prepayments and other current assets explanation above.
Regulatory Liabilities Current	27	12	14	Higher balance primarily due to timing related DSM programs of $9m and over-recovery of fuel costs during Q2 related to FAC of $4m.
Other Current Liabilities	139	138	0	
Total Current Liabilities	679	819	(139)	
Debt - Affiliated Company	59	61	(2)	
Debt [1]	5,128	5,208	(79)	
Total Debt	5,188	5,269	(81)	
Deferred Tax Liabilities	1,406	1,352	54	
Investment Tax Credit	129	129	0	
Accum Provision for Pension & Related Benefits	274	262	12	
Asset Retirement Obligation	437	281	156	Primarily due to revalued ARO's to reflect updates in the estimated cash flows for ash and environmental ponds of $162m as a result of the enactment of the Coal Combustion Residuals (CCR) Rule.
Regulatory Liabilities Non Current	951	943	8	
Derivative Liability	40	43	(3)	
Other Liabilities	215	268	(52)	Due to reclassification of retainage related to CR7 project from long-term to short-term ($38m), decrease in post-retirement liability due to roll forward of participant census data and VEBA contributions ($21m) partially offset by increased post-retirement and post-employment expense of $5m.
Total Deferred Credits and Other Liabilities	3,452	3,278	174	
Equity	4,329	4,363	(34)	
Total Liabilities and Equity	**$ 13,648**	**$ 13,728**	**$ (80)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

YTD	Actual	Budget	Variance	Comments
Net Income	177	139	38	Due to higher gross margin and lower O&M partially offset by higher taxes. See Income Statement.
Depreciation	201	205	(4)	
Deferred Income Taxes	145	107	38	Primarily due to the impact of the bonus depreciation extension partially offset by increased utilization of NOL's.
Other Balance Sheet Movements	91	111	(20)	Budget does not include non cash effect of regulatory over/under accrual adjustments.
Funds From Operations	**615**	**562**	**52**	
Changes in accounts receivables	25	(14)	39	Primarily due to a decrease in unbilled revenue and customer accounts receivable related to lower volumes driven by seasonality.
Changes in inventories	54	54	0	
Change in Accounts Payable	10	(64)	74	Budget does not remove the effect of the capital expenditures accrual which is reflected in actuals.
Change in Working Capital	**89**	**(24)**	**113**	
Operating Cash flow	**703**	**538**	**166**	
Capex	(630)	(602)	(29)	
Other Investing	5	0	5	
Loans to Affiliates	0	0	0	
Investing Cash flow	**(626)**	**(602)**	**(24)**	
Dividends	(109)	(123)	14	Lower dividends to PPL primarily due to an offset resulting from an overpayment that occurred in December 2014.
Equity Infusion	20	96	(76)	Due to resolutions declared having lower equity infusions than modeled in the budget to achieve 53% equity/debt ratio.
Net Borrowings	4	86	(82)	See explanation for equity infusion above.
Other	0	0	0	
Financing Cash flow	**(85)**	**59**	**(144)**	
Net increase (decrease) in cash	**(8)**	**(5)**	**(2)**	



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Combined KU and LG&E ROE June 2015

KU and LG&E Combined

Reconciliation of Allowed Return to

12 months ended Jun-2015 Regulatory Return

and ROE from Ongoing Operations

Allowed Return [1]		10.28%	
Adjustments (net of tax):			
Change in capitalization - non mechanism	-2.00%		Growth in non-mechanism capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.25%		Additional borrowings offset by favorable rates
Change in margins	2.49%		Primarily new rates since last rate cases
Change in allowed expenses	-1.54%		Inflationary increases
		-1.30%	
Actual Regulated ROE		8.99%	

(1) Based on the most recent base rate filings with test years ending 3/31/12 KPSC, 12/31/13 FERC, 12/31/12 VA.

Performance Report

July 2015

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Kentucky Regulated Dashboard — July 2015

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.68	2.40	1.00	1.13	1.41	1.03
Employee lost-time incidents	4	0	6	4	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,366	3,330	20,630	20,359	35,916	34,582
Utility EFOR	2.5%	5.9%	3.7%	5.9%	N/A	5.9%
Utility EAF	94.4%	92.6%	83.9%	85.2%	N/A	83.8%
Steam Fleet Commercial Availability	95.2%	92.0%	94.5%	92.0%	N/A	92.0%
Combined SAIFI	0.13	0.16	0.66	0.74	N/A	1.19
Combined SAIDI (minutes)	13.98	16.56	59.09	68.83	N/A	106.60
GwH Sales						
Residential	1,064	1,105	6,639	6,399	11,123	10,842
Commercial	751	763	4,570	4,615	7,883	7,916
Industrial	846	891	5,761	5,832	9,997	10,024
Municipals	179	184	1,123	1,105	1,910	1,890
Other	256	252	1,652	1,589	2,780	2,723
Off-System Sales	48	20	287	234	311	311
Total	3,144	3,215	20,032	19,774	34,003	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.42%			
Commercial			-1.59%			
Industrial			1.04%			
Municipal			-0.94%			
Other			-0.66%			
Total			-0.63%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(1)]	12.5%	13.1%	9.8%	8.2%	9.3%	8.9%
Electric Margins	$168	$176	$1,037	$1,002	$1,783	$1,774
Gas Margins	9	9	98	99	163	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$1	$3	$13	$34	$39	$47
ECR	40	50	375	373	600	569
Generation	4	31	57	102	141	149
Transmission	5	3	34	34	68	60
Electric Distribution	15	19	89	99	166	162
Gas Distribution	7	10	43	46	88	83
Customer Services	1	2	9	9	19	17
IT and Other	2	3	17	23	39	38
Total	$76	$121	$638	$722	$1,160	$1,125
O&M ($ millions)[(2)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$38	$37	$276	$283	$471	$471
General Counsel & HR	3	3	20	22	39	40
Finance, IT, & Supply Chain	6	7	44	48	81	81
Burdens & Other Charges	11	14	92	104	159	176
Total	$58	$62	$432	$457	$750	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,463	3,570	3,463	3,570	3,551	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	3	0	15	8	N/A	9
NERC Possible Violations[(3)]	0	1	5	4	N/A	7

Variance Explanations

• Current month lower margins driven by mild weather resulting in lower sales volumes and $9 million lower demand and energy revenues.

•YTD higher margins due to a combination of favorable weather and plant/system performance earlier in the year resulting in $13 million favorable demand and energy revenue and $3 million from the sale of excess generation. ECR margins up $17 million with higher spending levels and other adjustments.

• Current month lower capital expenditures of $45 million due primarily to planned spending related to the Paddy's Run gas pipe line and Dix Dam leakage projects being moved to 2016 and milestone shifts for the environmental air projects at Ghent and Trimble County.

• YTD lower capital expenditures of $84 million due primarily to decreased spend and test energy budgeted but not used at Cane Run, timing changes for the Ohio Falls Redevelopment project to later this year and planned spending related to the Paddy's Run gas pipe line and Dix Dam leakage projects being moved to 2016.

• YTD lower O&M due to $11 million lower labor and burden costs, $6 million in lower materials and consulting costs, $4 million due to timing for maintenance outages and $3 million in uncollectible accounts partially offset by $1 million higher storm restoration costs.

• Fifteen environmental events have occurred YTD. Thirteen of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred during May at Ghent and a oil spill into the Ohio River at Mill Creek in June due to equipment failure.

Major Developments

• July marks the second consecutive month that LKE has responded to numerous severe weather events bringing strong winds and lightning. These conditions resulted in approximately 160,000 outages. At times, restoration efforts were further complicated by heat indexes above 100 degrees, and repeated downpours across the various service areas. The system and our team have responded well in maintaining and restoring service in a timely and safe manner.

• LKE is evaluating the impact of the EPA's Clean Power Plan which limits greenhouse gas emissions from power plants. The final emission limit for Kentucky to occur by 2030 is 31 percent below actual emissions (tons) in 2014, and 27 percent below the KY emission rate (pounds/mwh) in the proposed regulation. States must submit its individual compliance plans to meet the new goals by 2018.

Significant Future Events

• The discovery phase continues for the Virginia rate case with an informal hearing scheduled for December 14, 2015.

• The Ghent 2, Trimble County 1 and Brown 3 fabric filter EPC contracts are progressing well with tie-in outages on schedule for October. Mill Creek 3 wet flue gas desulfurization system and fabric filter EPC work is also well underway for mid-2016 completion. Lastly, site excavation work for the Brown Solar project continues and bids for the EPC contract are under evaluation.

(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget and Forecast (Month) — July 2015

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 267	$ 291	$ (24)	See "Electric Margin" explanation below.	$ 267	$ 274	$ (7)	Due to lower energy volumes.
Gas Revenues	12	13	(0)		12	13	(1)	
Total Revenues	279	304	(25)		279	287	(8)	
Cost of Sales:								
Fuel Electric Costs	82	95	13	See "Electric Margin" explanation below.	82	93	11	Due to a combination of lower volumes driven by mild weather and lower commodity costs for coal and natural gas.
Gas Supply Expenses	4	4	(0)		4	4	1	
Purchased Power	5	6	1		5	5	1	
Other Electric Cost	12	14	2		12	12	(0)	
Total Cost of Sales	103	118	15		103	115	12	
Gross Margin:								
Electric Margin	168	176	(9)	Lower margins driven by mild weather resulting in lower sales volumes and $9 million lower demand and energy revenues.	168	164	4	
Gas Margin	9	9	(0)		9	9	(0)	
Total Gross Margin	176	185	(9)		176	172	4	
Operating Expenses:								
O&M	58	62	4		58	65	8	Lower O&M primarily due to $3 million lower labor and burden costs and $4 million in lower materials and consulting costs.
Depreciation & Amortization	29	29	1		29	29	0	
Taxes, Other than Income	4	5	0		4	4	0	
Total Operating Expenses	91	96	5		91	99	8	
Other income (expense)	(1)	(0)	(1)		(1)	0	(1)	
EBIT	84	90	(5)		84	73	11	
Interest Expense	14	15	0		14	15	0	
Income from Ongoing Operations before income taxes	70	75	(5)		70	59	11	
Income Tax Expense	26	29	2		26	23	(4)	
Net Income (loss) from ongoing operations	**43**	**46**	**$ (3)**		**$ 43**	**36**	**$ 7**	
Non Operating Income	-	-	-		-	-	-	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 43	$ 46	$ (3)		$ 43	$ 36	$ 7	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 40	$ 43	$ (3)		$ 40	$ 34	$ 7	
Earnings Per Share	$ 0.06	$ 0.06	$ (0.00)		$ 0.06	$ 0.05	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) **July 2015**

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,694	$ 1,700	$ (6)	See Electric Margin variance explanation below.
Gas Revenues	200	213	(13)	See Gas Supply Expenses explanation below.
Total Revenues	1,894	1,914	(20)	
Cost of Sales:				
Fuel Electric Costs	552	577	25	Due to a combination of lower volumes and lower commodity costs for natural gas.
Gas Supply Expenses	101	114	13	Due to lower net purchases of $12 million, timing of pipeline demand charges of $4 million and timing of net exchange gas of $4 million partially offset by less gas to storage activity of $6 million.
Purchased Power	30	35	5	Lower purchased power due to mild weather.
Other Electric Cost	74	86	12	Due to lower ECR expense of $6 million, scrubber reactant expense of $4 million and DSM expense of $2 million.
Total Cost of Sales	759	813	54	
Gross Margin:				
Electric Margin	1,037	1,002	35	Higher margins due to a combination of favorable weather and plant/system performance earlier in the year resulting in $13 million favorable demand and energy revenue and $3 million from the sale of excess generation. ECR margins up $17 million with higher spending levels and other adjustments.
Gas Margin	98	99	(1)	
Total Gross Margin	1,135	1,101	34	
Operating Expenses:				
O&M	432	457	25	Lower O&M due to $11 million lower labor and burden costs, $6 million in lower materials and consulting costs, $4 million due to timing for maintenance outages and $3 million in uncollectible accounts partially offset by $1 million higher storm restoration costs.
Depreciation & Amortization	202	207	6	Lower depreciation expense primarily due to the timing of retirement and in service dates related to Cane Run units and other project completion updates.
Taxes, Other than Income	31	32	1	
Total Operating Expenses	665	697	32	
Other income (expense)	(3)	(4)	2	
EBIT	467	399	68	
Interest Expense	99	102	3	
Income from Ongoing Operations before income taxes	368	297	71	
Income Tax Expense	139	112	(27)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**228**	**185**	**$ 43**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 220	$ 185	$ 35	
KY Regulated Financing Costs	(20)	$ (20)	(0)	
KY Regulated Net Income	$ 200	$ 165	$ 35	
Earnings Per Share	$ 0.31	$ 0.25	$ 0.06	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — July 2015

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						$ (10)						$ 12
Energy Volumes (a)	3,096,871	3,196,196	(99,324)		$ (2.9)		19,743,640	19,541,455	202,185		$ 10.8	
Energy Prices (a)					$ (4.8)						$ (5.5)	
Customer Charges (Avg. Customers)	945,408	956,741	(11,333)		$ (0.8)		944,499	955,517	(11,018)		(0.9)	
Demand Charges (b)	$ 49	$ 50			$ (1.4)		291	283			7.7	
ECR:						$ 2						$ 17
Average Rate Base	$ 1,959	$ 1,960	$ (1)	10.06%	$ (0.0)		$ 1,826	$ 1,797	$ 29	10.16%	$ 1.6	
Cost of Capital	10.29%	10.06%	0.23%	$ 1,959	$ 0.3		10.31%	10.16%	0.15%	$ 1,826	1.4	
Jurisdictional Factor	91.60%	92.01%	-0.41%	$ 1,959	$ (0.1)		89.65%	90.16%	-0.51%	$ 1,826	(0.6)	
Other					$ 1.9						14.5	
DSM:						$ (1)						$ 1
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.3	$ 0.3			$ 0.0	
Lost Sales	0.0	1.1			$ (1.1)		8.8	7.4			$ 1.4	
Incentive	0.1	0.1			$ (0.0)		0.5	0.6			$ (0.1)	
Balancing Adjustment	0.0	-			$ 0.0		0.0	-			$ 0.0	
Net Fuel Recovery	$ (1.2)	$ (0.3)				$ (1)	$ (3.7)	$ (2.4)				$ (1)
Purchase Power Demand	(3.0)	(3.1)				$ 0	(17.0)	(17.9)				$ 1
Transmission	1.2	0.8				$ 0	6.3	4.6				$ 2
Other	(1.0)	(1.5)				$ 0	(9.6)	(10.4)				$ 1
Retail Margin Variance						$ (9)						$ 32
Off-System Margin Variance						$ (0)						$ 3
Electric Margin Variance						$ (9)						$ 35

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 56	1,064,195	$ 52.28	$ 59	1,105,304	$ 53.01	($3.0)	($2.2)	($0.8)
Commercial	23	751,444	30.89	25	763,039	33.41	($2.3)	($0.4)	($1.9)
Industrial	7	846,231	8.50	9	891,401	9.95	($1.7)	($0.4)	($1.2)
Municipals	1	179,061	4.53	1	184,010	5.22	($0.1)	($0.0)	($0.1)
Other	6	255,940	21.69	6	252,441	24.72	($0.7)	$0.1	($0.8)
Native Load Total	**$ 92**	**3,096,871**	**$ 29.84**	**$ 100**	**3,196,196**	**$ 31.33**	**($7.7)**	**($2.9)**	**($4.8)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 327	6,638,865	$ 49.25	$ 316	6,399,325	$ 49.39	$10.9	$11.6	($0.7)
Commercial	141	4,570,310	30.91	146	4,614,701	31.56	($4.4)	($1.4)	($3.0)
Industrial	52	5,760,296	8.98	53	5,832,321	9.11	($1.4)	($0.7)	($0.8)
Municipals	6	1,123,460	5.18	6	1,105,138	5.22	$0.1	$0.1	($0.0)
Other	38	1,650,708	22.85	38	1,589,970	23.68	$0.1	$1.1	($1.1)
Native Load Total	**$ 563**	**19,743,640**	**$ 28.54**	**$ 558**	**19,541,455**	**$ 28.57**	**$5.2**	**$10.8**	**($5.5)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	16	17	(1)	95	94	1
Industrial	20	20	0	117	116	1
Municipals	5	6	(1)	39	36	3
Other	7	7	0	40	38	2
Native Load Total	**49**	**50**	**(1)**	**291**	**283**	**8**

Weather - Avg. Hourly Temperature [(1)]	MTD			YTD		
	Act	+/- Bud		Act	+/- Bud	
(°F) Louisville Heating Season	-	-	-	41	3	8%
(°F) Lexington Heating Season	-	-	-	39	3	9%
(°F) Louisville Cooling Season	78	(0)	0%	75	2	2%
(°F) Lexington Cooling Season	75	(1)	-2%	72	1	1%

[(1)] Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — July 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 35**	**$ 35**		**$ (0)**
Gas Supply Costs								
Gas Supply Costs	(3)	(3)	$ 1		(97)	(110)	13	
GSC Revenue	3	3	$ (0)		97	110	(13)	
Net Gas Supply Costs				**0**				**$ 0**
Retail Gas (a)	**2**	**3**		**(0)**	**58**	**56**		**$ 2**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**$ -**
DSM	**0**	**0**		**(0)**	**0**	**0**		**$ 0**
GLT	**1**	**1**		**0**	**6**	**6**		**$ (0)**
WNA	**(0)**	**-**		**(0)**	**(3)**	**-**		**$ (3)**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**$ 0**
Gas Margin Variance				**$ (0)**				**$ (1)**

(a) Retail and wholesale gas sales - excludes GSC

MTD	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 1	353,623	$ 2.89	$ 1	380,488	$ 2.79	($0.0)	($0.1)	$0.0
Commercial	0	239,598	2.02	1	230,064	2.21	($0.0)	$0.0	($0.0)
Industrial	0	102,418	1.51	0	91,491	1.83	($0.0)	$0.0	($0.0)
Public Authority	0	24,396	1.81	0	39,502	2.14	($0.0)	($0.0)	($0.0)
Transportation	0	864,254	0.50	0	731,008	0.47	$0.1	$0.1	$0.0
Interdepartmental	0	21,907	5.20	0	284,181	1.76	($0.4)	($0.5)	$0.1
Ultimate Consumer	$ 2	1,606,196	$ 1.40	$ 3	1,756,734	$ 1.52	($0.4)	($0.5)	$0.1

YTD	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 36	13,556,529	$ 2.65	$ 35	13,088,947	$ 2.65	$1	$ 1	$ 0
Commercial	13	6,232,207	2.05	12	5,809,873	2.10	$1	$ 1	$ (0)
Industrial	2	916,704	1.76	2	835,478	1.84	$0	$ 0	$ (0)
Public Authority	2	924,581	2.00	2	959,447	2.06	($0)	$ (0)	$ (0)
Transportation	4	8,548,176	0.46	3	6,668,948	0.44	$1	$1	$0
Interdepartmental	2	261,101	8.26	3	989,844	3.18	($1)	($2)	$1
Ultimate Consumer	$ 58	30,439,298	$ 1.91	$ 56	28,352,537	$ 1.99	$2	$1	$1

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 14	$ 14	$ 0	$ 1	$ (0)	$ (1)	$ 1		$ 0
Project Engineering	0	0	(0)	(0)		0	(0)		0
Transmission	3	3	0	(0)		0	0		0
Energy Supply and Analysis	1	1	(0)	(0)		0	0		(0)
Generation Services	1	1	0	0		0	(0)		0
Electric Distribution	9	7	(2)	(1)		(1)	0	(0)	(0)
Gas Distribution	3	3	0	(0)		0	0	(0)	(0)
Safety and Security	0	0	0	0		(0)	0	0	(0)
Customer Services	7	8	1	0		0	0	1	(0)
Chief Operations Officer	**38**	**37**	**(1)**	**(0)**	**(0)**	**(2)**	**1**	**1**	**(0)**
General Counsel	2	3	0	(0)		0	(0)		0
Human Resources	1	1	0	0		0	0		0
General Counsel & HR	**3**	**3**	**0**	**(0)**		**0**	**(0)**		**0**
Information Technology	4	5	1	0		(0)	0		0
Supply Chain	0	0	(0)	(0)		(0)	0		0
Finance	2	2	0	(0)		0	0		0
Chief Financial Officer	**6**	**7**	**1**	**0**		**(0)**	**0**		**0**
Corporate	**11**	**14**	**4**	**3**		**0**	**(0)**	**(0)**	**0**
O&M Total MTD	**$ 58**	**$ 62**	**$ 4**	**$ 3**	**$ (0)**	**$ (1)**	**$ 1**	**$ 1**	**$ 1**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 135	$ 138	$ 3	$ (0)	4	$ (1)	$ 2		$ (3)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	18	17	(0)	(0)		(1)	1		0
Energy Supply and Analysis	5	5	0	0		0	0		0
Generation Services	8	8	1	0		0	(0)		0
Electric Distribution	42	42	(0)	(1)		1	0	0	(0)
Gas Distribution	19	19	(1)	(0)		0	(0)	(0)	(1)
Safety and Security	2	3	0	0		(0)	0	0	(0)
Customer Services	46	51	5	1		1	0	3	(1)
Chief Operations Officer	**276**	**283**	**7**	**(1)**	**4**	**1**	**3**	**3**	**(4)**
General Counsel	16	18	2	0		1	(0)		1
Human Resources	4	4	1	0		0	(0)		0
General Counsel & HR	**20**	**22**	**3**	**1**		**2**	**(0)**		**1**
Information Technology	31	34	3	2		(0)	0		1
Supply Chain	2	2	(0)	(0)		(0)	0		0
Finance	11	12	1	0		0	0		1
Chief Financial Officer	**44**	**48**	**3**	**2**		**(0)**	**0**		**2**
Corporate	**92**	**104**	**11**	**8**		**(0)**	**(0)**	**0**	**4**
O&M Total YTD	**$ 432**	**$ 457**	**$ 25**	**$ 10**	**$ 4**	**$ 3**	**$ 3**	**$ 3**	**$ 1**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 226	$ 225	$ (2)	$ (2)	$ 3	$ (7)	$ (0)		$ 3
Project Engineering	1	1	0	0		(0)	(0)		0
Transmission	29	29	(0)	(0)		(1)	1		(0)
Energy Supply and Analysis	9	9	0	0		(0)	0		0
Generation Services	14	14	0	(0)		0	(0)		(0)
Electric Distribution	69	70	1	0		0	(0)	0	0
Gas Distribution	34	33	(1)	(0)		(0)	0	(0)	(0)
Safety and Security	4	4	0	0		0	0	0	(0)
Customer Services	86	87	1	1		(0)	1	0	(0)
Chief Operations Officer	**471**	**471**	**(1)**	**(1)**	**3**	**(7)**	**2**	**(0)**	**2**
General Counsel	32	33	0	0		0	0		(0)
Human Resources	7	7	0	0		0	0		(0)
General Counsel & HR	**39**	**40**	**1**	**0**		**1**	**0**		**(0)**
Information Technology	57	58	1	1		(1)	(0)		1
Supply Chain	4	4	0	0		0	0		0
Finance	20	20	(0)	0		(0)	0		(0)
Chief Financial Officer	**81**	**81**	**1**	**1**		**(1)**	**(0)**		**0**
Corporate	**159**	**176**	**17**	**14**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 750**	**$ 767**	**$ 17**	**$ 14**	**$ 3**	**$ (8)**	**$ 1**	**$ 0**	**$ 6**

Note: Schedules may not sum due to rounding.

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Financing Activities — July 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	(0.0)	923.9	923.9	(0.0)	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 6.0**	**$ 8.0**	**$ 2.0**	**$ 11.7**	**$ 13.8**	**$ 2.0**
Rate	**1.08%**	**1.44%**	**0.36%**	**1.10%**	**1.48%**	**0.37%**	**1.27%**	**1.49%**	**0.22%**
FMB/Sr Nts [1]									
Beg Bal	$ 3,643.6	$ 3,643.6	$ 0.0	$ 3,642.7	$ 3,642.7	$ -	$ 3,642.7	$ 3,642.7	$ -
End Bal	3,643.7	3,643.7	0.0	3,643.7	3,643.7	0.0	3,794.4	3,794.4	0.0
Ave Bal	**$ 3,643.6**	**$ 3,643.6**	**$ 0.0**	**$ 3,643.2**	**$ 3,643.2**	**$ 0.0**	**$ 3,756.1**	**$ 3,756.1**	**$ -**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ (0.0)**	**$ 80.5**	**$ 80.5**	**$ (0.0)**	**$ 148.1**	**$ 148.3**	**$ 0.2**
Rate	**3.66%**	**3.66%**	**0.00%**	**3.75%**	**3.75%**	**0.00%**	**3.94%**	**3.95%**	**0.01%**
Short-term Debt									
Beg Bal	$ 620.1	$ 701.2	$ 81.1	$ 615.4	$ 615.4	$ -	$ 615.4	$ 615.4	$ -
End Bal	609.2	700.6	91.4	609.2	700.6	91.4	670.4	662.0	(8.4)
Ave Bal	**$ 614.6**	**$ 700.9**	**$ 86.3**	**$ 612.3**	**$ 658.0**	**$ 45.7**	**$ 600.1**	**$ 633.9**	**$ 33.8**
Interest Exp	**$ 0.4**	**$ 0.6**	**$ 0.2**	**$ 2.7**	**$ 3.9**	**$ 1.2**	**$ 4.4**	**$ 6.0**	**$ 1.7**
Rate	**0.75%**	**0.94%**	**0.19%**	**0.75%**	**1.01%**	**0.26%**	**0.73%**	**0.95%**	**0.23%**
Total End Bal	**$ 5,176.8**	**$ 5,268.3**	**$ 91.4**	**$ 5,176.8**	**$ 5,268.3**	**$ 91.4**	**$ 5,388.7**	**$ 5,380.2**	**$ (8.5)**
Total Average Bal	**$ 5,182.2**	**$ 5,268.4**	**$ 86.3**	**$ 5,179.4**	**$ 5,225.1**	**$ 45.7**	**$ 5,280.1**	**$ 5,314.0**	**$ 33.8**
Total Expense Excl I/C [2]	**$ 14.4**	**$ 14.6**	**$ 0.2**	**$ 99.2**	**$ 102.1**	**$ 2.9**	**$ 183.6**	**$ 186.3**	**$ 2.7**
Rate	**3.23%**	**3.23%**	**0.00%**	**3.25%**	**3.32%**	**0.07%**	**3.48%**	**3.51%**	**0.03%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 134		$ 166
LG&E	500	264		236
KU	598	211	$ 198	189
TOTAL	$ 1,398	$ 609	$ 198	$ 591

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	36.3%	3%	27.2%	-5%
FFO to Debt - KU	29.3%	4%	23.8%	1%
Debt to EBITDA - LG&E [2]	3.32	-0.17	3.56	-0.02
Debt to EBITDA - KU [2]	3.61	-0.23	3.56	-0.14
Debt to Capitalization - LG&E [3]	46.6%	0%	47.0%	0%
Debt to Capitalization - KU [3]	46.4%	0%	47.0%	0%

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet

July 2015

($ Millions)

	7/31/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 12	$ 16	$ (4)	
Accounts Receivable (Trade)	398	418	(21)	
Inventory	252	258	(7)	
Deferred Income Taxes	42	16	26	Due to NOL utilization during the 1st half of 2016 of $20m and an intercompany transfer related to allocations from PPL of $5m.
Regulatory Assets Current	25	39	(14)	Due to lower balances related to GSC ($7 million) and FAC ($9 million) mechanisms partially offset by higher ECR balance ($3 million).
Prepayments and other current assets	45	185	(140)	Lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	774	933	(159)	
Property, Plant, and Equipment	11,072	10,983	89	
Intangible Assets	144	144	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	666	660	6	
Goodwill	997	997	-	
Other Long-term Assets	90	104	(14)	Primarily due to return of collateral as a result of update of credit rating from S&P ($12m).
Total Assets	**$ 13,744**	**$ 13,822**	**$ (78)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 326	$ 354	$ (28)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	51	52	(0)	
Derivative Liability	86	71	15	Due to lower than expected interest rates on interest rate swaps.
Accrued Taxes	89	229	(139)	See Prepayments and other current assets explanation above.
Regulatory Liabilities Current	30	12	18	Higher balance primarily due to timing related DSM programs of $10m and over-recovery of fuel costs related to FAC of $7m.
Other Current Liabilities	156	153	3	
Total Current Liabilities	740	871	(131)	
Debt - Affiliated Company	59	60	(1)	
Debt [(1)]	5,118	5,208	(90)	
Total Debt	5,177	5,268	(91)	
Deferred Tax Liabilities	1,406	1,352	54	
Investment Tax Credit	129	129	0	
Accum Provision for Pension & Related Benefits	276	263	13	
Asset Retirement Obligation	438	282	156	Primarily due to revalued ARO's to reflect updates in the estimated cash flows for planned pond closures of $162m as a result of the enactment of the Coal Combustion Residuals (CCR) Rule.
Regulatory Liabilities Non Current	946	936	10	
Derivative Liability	42	43	(1)	
Other Liabilities	218	268	(51)	Primarily due to reclassification of retainage related to CR7 project from long-term to short-term ($38m) and a decrease in post-retirement liability due to roll forward of participant census data and VEBA contributions ($21m).
Total Deferred Credits and Other Liabilities	3,455	3,274	181	
Equity	4,372	4,409	(37)	
Total Liabilities and Equity	**$ 13,744**	**$ 13,822**	**$ (78)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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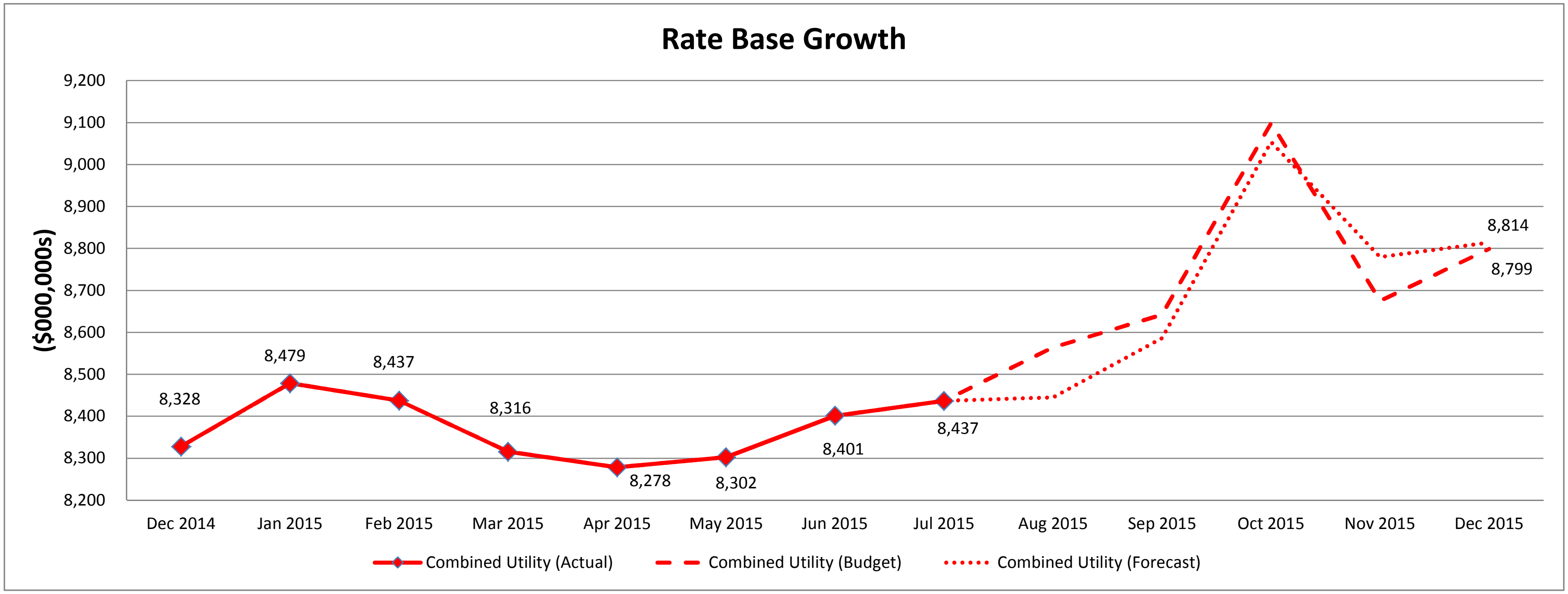
Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,328
8,479
8,437
8,316
8,278
8,302
8,401
8,437
8,814
8,799
Dec 2014
Jan 2015
Feb 2015
Mar 2015
Apr 2015
May 2015
Jun 2015
Jul 2015
Aug 2015
Sep 2015
Oct 2015
Nov 2015
Dec 2015
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Performance Report

August 2015

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Kentucky Regulated Dashboard — August 2015

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	2.24	1.63	1.15	1.24	1.41	1.03
Employee lost-time incidents	1	1	7	5	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,981	3,385	23,611	23,744	35,281	34,582
Utility EFOR	5.6%	5.9%	3.9%	5.9%	N/A	5.9%
Utility EAF	90.6%	92.6%	84.9%	86.1%	N/A	83.8%
Steam Fleet Commercial Availability	89.1%	92.0%	94.2%	92.0%	N/A	92.0%
Combined SAIFI	0.13	0.16	0.06	0.12	N/A	1.19
Combined SAIDI (minutes)	5.87	9.29	64.95	78.12	N/A	106.60
GwH Sales						
Residential	925	1,125	7,564	7,524	11,123	10,842
Commercial	742	772	5,312	5,387	7,883	7,916
Industrial	856	923	6,617	6,755	9,997	10,024
Municipals	170	188	1,293	1,293	1,910	1,890
Other	258	255	1,910	1,844	2,780	2,723
Off-System Sales	26	11	313	245	311	311
Total	2,977	3,274	23,009	23,048	34,003	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.62%			
Commercial			-0.90%			
Industrial			0.69%			
Municipal			-0.74%			
Other			-0.90%			
Total			-0.65%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(1)]	12.2%	13.6%	10.1%	8.9%	9.3%	8.9%
Electric Margins	$165	$179	$1,202	$1,180	$1,775	$1,774
Gas Margins	9	9	107	108	164	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$0	$3	$14	$37	$39	$47
ECR	45	50	419	424	593	569
Generation	5	5	63	108	139	149
Transmission	7	3	41	37	68	60
Electric Distribution	16	18	105	118	173	162
Gas Distribution	8	9	52	56	89	83
Customer Services	1	2	11	11	21	17
IT and Other	3	3	20	26	39	38
Total	$86	$94	$724	$815	$1,162	$1,125
O&M ($ millions)[(2)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$36	$35	$312	$319	$469	$471
General Counsel & HR	3	4	23	26	38	40
Finance, IT, & Supply Chain	6	7	51	54	79	81
Burdens & Other Charges	11	14	103	118	162	176
Total	$56	$60	$488	$517	$748	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,453	3,569	3,453	3,569	3,545	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	1	15	9	N/A	9
NERC Possible Violations[(3)]	1	1	6	5	N/A	7

Variance Explanations

• Current month lower margins driven by unseasonably mild weather leading to lower sales volumes resulting in $15 million lower retail electric base energy revenues.

•YTD higher margins primarily due to higher ECR margins of $17 million resulting from greater spending levels and other adjustments and $3 million from the sale of excess generation.

• YTD lower capital expenditures of $92 million due primarily to decreased spend and test energy budgeted but not used at Cane Run, delayed spending on several projects until later this year and planned timing shifts related to the Paddy's Run gas pipe line and Dix Dam leakage projects being moved to 2016.

• YTD lower O&M due to $15 million lower labor and burden costs, $5 million in lower materials and consulting costs, $4 million due to timing for maintenance outages, $3 million in lower uncollectible accounts and $2 million in lower other A&G expenses partially offset by $1 million higher storm restoration costs.

• Fifteen environmental events have occurred YTD. Thirteen of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred during May at Ghent and a oil spill into the Ohio River at Mill Creek in June due to equipment failure.

Major Developments

• In both Louisville and Lexington, August 2015 ranked as the third coolest in the past 20 years driving retail electric sales volumes for LG&E and KU down 9% below budget.

• Upon completion of the competitive bid process, the Company awarded the Brown Solar Facility EPC contract to AMEC and expect to execute the contract in late September. AMEC is also the contractor for the Trimble County 1 and Brown 3 baghouse projects. The 10 MW project will be the largest utility scale solar PV facility in Kentucky, and is expected to be in service before the end of 2016.

• KU filed a settlement agreement with FERC to resolve the 2013 rate case with the departing municipal customers. The rate formulas are identical to those agreed to with the two remaining municipal customers except for ROE, using 10.25% instead of 10%. One small issue related to an interruptible provision and credit for one of the departing municipals remains open and will proceed to litigation.

Significant Future Events

• The discovery phase continues for the Virginia rate case with an informal hearing scheduled for December 14, 2015.

• The Ghent 2, Trimble County 1 and Brown 3 fabric filter EPC contracts are progressing well with tie-in outages on schedule for October. Mill Creek 3 wet flue gas desulfurization system and fabric filter EPC work is also well underway for mid-2016 completion. Lastly, site prep and soil excavation for the Brown Solar project is nearing completion.

(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues for YTD Actual is believed to be minimal risk.

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Income Statement: Actual vs. Budget and Forecast (Month) — August 2015

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 260	$ 297	$ (37)	See "Electric Margin" explanation below.	$ 260	$ 280	$ (20)	Due to lower energy volumes due to unseasonably mild weather.
Gas Revenues	12	13	(1)		12	13	(1)	
Total Revenues	272	310	(38)		272	294	(21)	
Cost of Sales:								
Fuel Electric Costs	77	97	20	See "Electric Margin" explanation below.	77	95	18	Due to lower energy volumes due to unseasonably mild weather.
Gas Supply Expenses	4	4	0		4	4	1	
Purchased Power	5	6	1		5	5	0	
Other Electric Cost	12	15	3		12	14	2	
Total Cost of Sales	99	122	24		99	119	21	
Gross Margin:								
Electric Margin	165	179	(14)	Lower margins driven by unseasonably mild weather leading to lower sales volumes resulting in $15 million lower retail electric base energy revenues.	165	165	(0)	
Gas Margin	9	9	(0)		9	9	(0)	
Total Gross Margin	174	188	(14)		174	174	(0)	
Operating Expenses:								
O&M	56	60	4		56	60	4	
Depreciation & Amortization	29	30	1		29	29	1	
Taxes, Other than Income	5	5	0		5	5	(0)	
Total Operating Expenses	89	94	5		89	94	5	
Other income (expense)	(1)	(0)	(0)		(1)	(0)	(0)	
EBIT	85	94	(9)		85	80	4	
Interest Expense	14	15	0		14	15	0	
Income from Ongoing Operations before income taxes	70	79	(9)		70	66	4	
Income Tax Expense	26	30	4		26	25	(1)	
Net Income (loss) from ongoing operations	**44**	**49**	**$ (5)**		**$ 44**	**41**	**$ 3**	
Non Operating Income	-	-	-		-	-	-	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 44	$ 48	$ (5)		$ 44	$ 41	$ 3	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 41	$ 46	$ (5)		$ 41	$ 38	$ 3	
Earnings Per Share	$ 0.06	$ 0.07	$ (0.01)		$ 0.06	$ 0.06	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — August 2015

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,954	$ 1,997	$ (43)	Due to lower volumes and prices driven by unseasonably mild weather.
Gas Revenues	212	226	(14)	See Gas Supply Expenses explanation below.
Total Revenues	2,166	2,224	(58)	
Cost of Sales:				
Fuel Electric Costs	630	675	45	Due to a combination of lower volumes and lower commodity costs for natural gas.
Gas Supply Expenses	105	118	13	Due to lower net purchases of $17 million, timing of net exchange gas of $4 million and timing of pipeline demand charges of $2 million partially offset by less gas to storage activity of $9 million.
Purchased Power	36	42	6	Lower purchased power due to mild weather.
Other Electric Cost	87	101	14	Due to lower ECR expense of $7 million, scrubber reactant expense of $5 million and DSM expense of $3 million.
Total Cost of Sales	858	935	78	
Gross Margin:				
Electric Margin	1,202	1,180	21	Primarily due to higher ECR margins of $17 million resulting from greater spending levels and other adjustments and $3 million from the sale of excess generation.
Gas Margin	107	108	(1)	
Total Gross Margin	1,309	1,289	20	
Operating Expenses:				
O&M	488	517	29	Lower O&M due to $15 million lower labor and burden costs, $5 million in lower materials and consulting costs, $4 million due to timing for maintenance outages, $3 million in lower uncollectible accounts and $2 million in lower other A&G expenses partially offset by $1 million higher storm restoration costs.
Depreciation & Amortization	231	237	6	Lower depreciation expense primarily due to the timing of retirement and in service dates related to Cane Run units and other project completion updates.
Taxes, Other than Income	36	37	1	
Total Operating Expenses	754	791	37	
Other income (expense)	(3)	(5)	1	
EBIT	551	493	58	
Interest Expense	113	117	3	
Income from Ongoing Operations before income taxes	438	376	62	
Income Tax Expense	166	142	(23)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**272**	**234**	**$ 38**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 264	$ 234	$ 31	
KY Regulated Financing Costs	(23)	$ (23)	(0)	
KY Regulated Net Income	$ 241	$ 211	$ 30	
Earnings Per Share	$ 0.37	$ 0.31	$ 0.06	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — August 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ (16)						$ (3)
Energy Volumes (a)	2,949,777	3,261,891	(312,114)		$ (12.4)		22,693,417	22,803,346	(109,929)		$ (0.8)	
Energy Prices (a)					$ (2.8)						$ (9.2)	
Customer Charges (Avg. Customers)	945,798	957,170	(11,372)		$ (0.2)		944,661	955,723	(11,062)		(1.1)	
Demand Charges (b)	$ 51	$ 51			$ (0.2)		342	334			7.6	
ECR:						$ 1						$ 17
Average Rate Base	$ 1,988	$ 1,996	$ (8)	10.10%	$ (0.1)		$ 1,846	$ 1,821	$ 25	10.16%	$ 1.5	
Cost of Capital	10.30%	10.10%	0.20%	$ 1,988	$ 0.3		10.31%	10.16%	0.15%	$ 1,846	1.7	
Jurisdictional Factor	92.07%	92.15%	-0.08%	$ 1,988	$ (0.0)		89.99%	90.46%	-0.47%	$ 1,846	(0.6)	
Other					$ 0.3						14.9	
DSM:						$ (1)						$ 0
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.4	$ 0.4			$ 0.0	
Lost Sales	0.1	1.1			$ (1.0)		8.9	8.5			$ 0.4	
Incentive	0.1	0.1			$ 0.0		0.6	0.7			$ (0.1)	
Balancing Adjustment	-	-			$ -		0.0	-			$ 0.0	
Net Fuel Recovery	$ (0.3)	$ (0.6)				$ 0	$ (4.0)	$ (3.0)				$ (1)
Purchase Power Demand	(2.9)	(3.1)				$ 0	(19.9)	(21.1)				$ 1
Transmission	1.3	0.8				$ 0	7.5	5.4				$ 2
Other	(0.3)	(1.5)				$ 1	(9.9)	(11.9)				$ 2
Retail Margin Variance						$ (14)						$ 19
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ (14)						$ 21

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 50	924,763	$ 54.34	$ 60	1,125,020	$ 53.02	($9.4)	($10.6)	$1.2
Commercial	24	742,067	31.73	26	772,365	33.60	($2.4)	($1.0)	($1.4)
Industrial	7	855,607	7.60	9	922,250	9.91	($2.6)	($0.7)	($2.0)
Municipals	1	169,065	3.76	1	187,399	5.22	($0.3)	($0.1)	($0.2)
Other	6	258,275	22.64	6	254,856	24.61	($0.4)	$0.0	($0.5)
Native Load Total	**$ 87**	**2,949,777**	**$ 29.42**	**$ 102**	**3,261,891**	**$ 31.27**	**($15.2)**	**($12.4)**	**($2.8)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 377	7,563,629	$ 49.87	$ 376	7,524,346	$ 49.93	$1.5	$1.7	($0.1)
Commercial	165	5,312,377	31.03	172	5,387,065	31.85	($6.8)	($2.3)	($4.4)
Industrial	58	6,615,903	8.80	62	6,754,571	9.22	($4.1)	($1.3)	($2.8)
Municipals	6	1,292,525	4.99	7	1,292,537	5.22	($0.3)	($0.0)	($0.3)
Other	44	1,908,983	22.82	44	1,844,826	23.81	($0.4)	$1.2	($1.5)
Native Load Total	**$ 650**	**22,693,417**	**$ 28.65**	**$ 660**	**22,803,346**	**$ 28.95**	**($10.0)**	**($0.8)**	**($9.2)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	17	18	(1)	111	112	(0)
Industrial	22	20	2	139	136	3
Municipals	5	6	(1)	44	42	2
Other	7	7	0	48	45	3
Native Load Total	**51**	**51**	**(0)**	**342**	**334**	**8**

Weather - Avg. Hourly Temperature [1]	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	-	-	-	41	3	8%
(°F) Lexington Heating Season	-	-	-	39	3	9%
(°F) Louisville Cooling Season	75	(2)	-3%	75	1	1%
(°F) Lexington Cooling Season	73	(3)	-4%	72	(0)	0%

[1] Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — August 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	$ 5	$ 5		(0)	$ 40	$ 40		$ (0)
Gas Supply Costs								
Gas Supply Costs	(3)	(3)	$ 1		(99)	(113)	14	
GSC Revenue	2	3	$ (1)		99	113	(14)	
Net Gas Supply Costs				(0)				$ (0)
Retail Gas (a)	3	3		(0)	61	59		$ 2
Wholesale Gas (a)	-	-		-	-	-		$ -
DSM	0	0		(0)	0	0		$ 0
GLT	1	1		0	7	7		$ 0
WNA	(0)	-		(0)	(3)	-		$ (3)
Other Margin	0	0		(0)	1	1		$ 0
Gas Margin Variance				$ (0)				$ (1)

(a) Retail and wholesale gas sales - excludes GSC

MTD	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 1	360,866	$ 2.87	$ 1	405,126	$ 2.79	($0.1)	($0.1)	$0.0
Commercial	0	241,836	2.03	1	229,752	2.21	($0.0)	$0.0	($0.0)
Industrial	0	94,955	1.89	0	93,794	1.82	$0.0	$0.0	$0.0
Public Authority	0	26,316	1.92	0	39,181	2.15	($0.0)	($0.0)	($0.0)
Transportation	0	919,016	0.49	0	761,813	0.46	$0.1	$0.1	$0.0
Interdepartmental	1	31,666	15.91	0	283,236	1.67	$0.0	($0.4)	$0.5
Ultimate Consumer	$ 3	1,674,655	$ 1.62	$ 3	1,812,901	$ 1.50	($0.0)	($0.5)	$0.5

YTD	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 37	13,917,395	$ 2.65	$ 36	13,494,072	$ 2.65	$1	$ 1	$ 0
Commercial	13	6,474,043	2.05	13	6,039,625	2.10	$1	$ 1	$ (0)
Industrial	2	953,361	1.88	2	929,272	1.84	$0	$ 0	$ 0
Public Authority	2	950,266	2.00	2	998,628	2.07	($0)	$ (0)	$ (0)
Transportation	4	9,467,192	0.46	3	7,430,761	0.44	$1	$1	$0
Interdepartmental	3	275,581	9.66	4	1,273,080	2.82	($1)	($3)	$2
Ultimate Consumer	$ 61	32,037,838	$ 1.90	$ 59	30,165,438	$ 1.96	$2	$0	$2

O&M									August 2015

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 14	$ 15	$ 0	$ 0	$ (0)	$ (0)	$ 0		$ 0
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	3	2	(0)	0		(0)	(0)		0
Energy Supply and Analysis	1	1	0	0		0	0		0
Generation Services	1	1	0	0		0	(0)		(0)
Electric Distribution	7	6	(1)	0		(1)	0	0	(0)
Gas Distribution	2	3	0	0		0	0	(0)	(0)
Safety and Security	0	0	0	(0)		(0)	0	0	0
Customer Services	8	7	(0)	(0)		0	0	(0)	0
Chief Operations Officer	**36**	**35**	**(0)**	**0**	**(0)**	**(1)**	**0**	**(0)**	**0**
General Counsel	3	3	0	0		(0)	0		0
Human Resources	0	1	0	0		0	0		0
General Counsel & HR	**3**	**4**	**0**	**0**		**(0)**	**0**		**0**
Information Technology	4	5	0	0		(0)	(0)		0
Supply Chain	0	0	0	0		0	(0)		0
Finance	1	2	0	0		0	(0)		0
Chief Financial Officer	**6**	**7**	**1**	**0**		**(0)**	**(0)**		**0**
Corporate	**11**	**14**	**4**	**3**		**0**	**(0)**	**0**	**1**
O&M Total MTD	**$ 56**	**$ 60**	**$ 4**	**$ 4**	**$ (0)**	**$ (1)**	**$ 0**	**$ (0)**	**$ 1**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 150	$ 152	$ 3	$ 0	4	$ (1)	$ 2		$ (3)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	20	20	(1)	(0)		(1)	1		0
Energy Supply and Analysis	6	6	0	0		0	0		0
Generation Services	9	9	1	0		0	(0)		0
Electric Distribution	49	48	(1)	(1)		1	0	0	(1)
Gas Distribution	22	22	(0)	0		0	0	(0)	(1)
Safety and Security	3	3	0	0		(0)	0	0	(0)
Customer Services	54	58	5	0		1	1	3	(1)
Chief Operations Officer	**$ 312**	**$ 319**	**7**	**(0)**	**4**	**1**	**4**	**3**	**(4)**
General Counsel	19	21	2	0		1	(0)		1
Human Resources	4	5	1	0		0	(0)		0
General Counsel & HR	**$ 23**	**$ 26**	**3**	**1**		**2**	**(0)**		**1**
Information Technology	35	39	3	2		(0)	0		1
Supply Chain	2	2	(0)	(0)		(0)	0		0
Finance	13	13	1	0		0	0		1
Chief Financial Officer	**$ 51**	**$ 54**	**4**	**2**		**(0)**	**0**		**2**
Corporate	**$ 103**	**$ 118**	**15**	**11**		**(0)**	**(0)**	**0**	**4**
O&M Total YTD	**$ 488**	**$ 517**	**$ 29**	**$ 14**	**$ 4**	**$ 2**	**$ 3**	**$ 3**	**$ 3**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 224	$ 225	$ 0	$ (1)	$ 4	$ (6)	$ 1		$ 3
Project Engineering	1	1	0	0		(0)	(0)		0
Transmission	29	29	(0)	(0)		(2)	1		0
Energy Supply and Analysis	9	9	0	0		(0)	0		0
Generation Services	13	14	0	0		1	0		(0)
Electric Distribution	72	70	(2)	(1)		(1)	0	0	(0)
Gas Distribution	34	33	(1)	(0)		(1)	0	(0)	(0)
Safety and Security	4	4	(0)	0		(0)	0	0	(0)
Customer Services	84	87	3	1		1	1	1	(1)
Chief Operations Officer	**$ 469**	**$ 471**	**1**	**(1)**	**4**	**(8)**	**3**	**1**	**2**
General Counsel	31	33	1	0		1	(0)		0
Human Resources	7	7	1	0		0	0		0
General Counsel & HR	**$ 38**	**$ 40**	**2**	**1**		**1**	**(0)**		**0**
Information Technology	56	58	2	3		(1)	(0)		0
Supply Chain	4	4	0	0		0	0		(0)
Finance	20	20	0	0		0	0		0
Chief Financial Officer	**$ 79**	**$ 81**	**3**	**3**		**(1)**	**(0)**		**1**
Corporate	**$ 162**	**$ 176**	**14**	**11**		**(0)**	**(0)**	**0**	**2**
O&M Total YTD	**$ 748**	**$ 767**	**$ 19**	**$ 14**	**$ 4**	**$ (9)**	**$ 3**	**$ 1**	**$ 5**

Note: Schedules may not sum due to rounding.

Financing Activities — August 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	0.0	923.9	923.9	0.0	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ 0.0**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 6.9**	**$ 9.2**	**$ 2.3**	**$ 11.7**	**$ 13.8**	**$ 2.0**
Rate	**1.08%**	**1.44%**	**0.37%**	**1.10%**	**1.47%**	**0.37%**	**1.27%**	**1.49%**	**0.22%**
FMB/Sr Nts [(1)]									
Beg Bal	$ 3,643.7	$ 3,643.7	$ 0.0	$ 3,642.7	$ 3,642.7	$ -	$ 3,642.7	$ 3,642.7	$ -
End Bal	3,643.9	3,643.9	0.0	3,643.9	3,643.9	0.0	3,794.4	3,794.4	0.0
Ave Bal	**$ 3,643.8**	**$ 3,643.8**	**$ 0.0**	**$ 3,643.3**	**$ 3,643.3**	**$ 0.0**	**$ 3,756.1**	**$ 3,756.1**	**$ -**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ (0.0)**	**$ 91.9**	**$ 91.9**	**$ (0.0)**	**$ 148.1**	**$ 148.3**	**$ 0.2**
Rate	**3.66%**	**3.66%**	**0.00%**	**3.74%**	**3.74%**	**0.00%**	**3.94%**	**3.95%**	**0.01%**
Short-term Debt									
Beg Bal	$ 609.2	$ 700.6	$ 91.4	$ 615.4	$ 615.4	$ -	$ 615.4	$ 615.4	$ -
End Bal	631.6	668.6	37.0	631.6	668.6	37.0	670.4	662.0	(8.4)
Ave Bal	**$ 620.4**	**$ 684.6**	**$ 64.2**	**$ 623.5**	**$ 642.0**	**$ 18.5**	**$ 600.1**	**$ 633.9**	**$ 33.8**
Interest Exp	**$ 0.4**	**$ 0.6**	**$ 0.2**	**$ 3.1**	**$ 4.5**	**$ 1.4**	**$ 4.4**	**$ 6.0**	**$ 1.7**
Rate	**0.70%**	**0.95%**	**0.25%**	**0.73%**	**1.03%**	**0.30%**	**0.73%**	**0.95%**	**0.23%**
Total End Bal	**$ 5,199.4**	**$ 5,236.4**	**$ 37.0**	**$ 5,199.4**	**$ 5,236.4**	**$ 37.0**	**$ 5,388.7**	**$ 5,380.2**	**$ (8.5)**
Total Average Bal	**$ 5,188.1**	**$ 5,252.3**	**$ 64.2**	**$ 5,190.7**	**$ 5,209.2**	**$ 18.5**	**$ 5,280.1**	**$ 5,314.0**	**$ 33.8**
Total Expense Excl I/C [(2)]	**$ 14.2**	**$ 14.6**	**$ 0.4**	**$ 113.4**	**$ 116.8**	**$ 3.4**	**$ 183.6**	**$ 186.3**	**$ 2.7**
Rate	**3.18%**	**3.24%**	**0.06%**	**3.24%**	**3.32%**	**0.08%**	**3.48%**	**3.51%**	**0.03%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 135		$ 165
LG&E	500	282		218
KU	598	214	$ 198	186
TOTAL	$ 1,398	$ 632	$ 198	$ 568

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	35.6%	3%	27.2%	-5%
FFO to Debt - KU	28.2%	3%	23.8%	1%
Debt to EBITDA - LG&E [(2)]	3.35	-0.14	3.56	-0.02
Debt to EBITDA - KU [(2)]	3.58	-0.26	3.56	-0.14
Debt to Capitalization - LG&E [(3)]	46.9%	0%	47.0%	0%
Debt to Capitalization - KU [(3)]	46.4%	0%	47.0%	0%

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet

August 2015

($ Millions)

	8/31/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 26	$ 16	$ 10	Due to timing of cash receipts.
Accounts Receivable (Trade)	396	424	(28)	
Inventory	258	262	(3)	
Deferred Income Taxes	44	16	29	Due to NOL utilization during the 1st half of 2016 of $20m and an intercompany transfer related to allocations from PPL of $5m.
Regulatory Assets Current	26	43	(17)	Due to lower balances related to GSC ($6 million) and FAC ($11 million) mechanisms.
Prepayments and other current assets	41	183	(142)	Primarily related to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	793	944	(151)	
Property, Plant, and Equipment	11,122	11,041	82	
Intangible Assets	140	140	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	668	658	9	
Goodwill	997	997	-	
Other Long-term Assets	91	104	(13)	Primarily due to return of collateral as a result of update of credit rating from S&P ($12m).
Total Assets	**$ 13,812**	**$ 13,886**	**$ (74)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 296	$ 355	$ (59)	Decreases in project engineering accruals ($57m).
Dividends Payable to Affiliated Companies	48	-	48	Dividend payable $48m issued to PPL based on Q2 2015 net income.
Customer Deposits	51	52	(1)	
Derivative Liability	87	71	15	Due to lower than expected interest rates on interest rate swaps.
Accrued Taxes	159	264	(105)	Due to income tax settlement (see Prepayments and other current assets explanation above) partially offset by 2014 tax return true-ups of $39m.
Regulatory Liabilities Current	29	12	17	Higher balance primarily due to timing related DSM programs of $9m and over-recovery of fuel costs related to FAC of $7m.
Other Current Liabilities	160	167	(6)	
Total Current Liabilities	830	920	(90)	
Debt - Affiliated Company	60	60	1	
Debt [1]	5,139	5,177	(38)	
Total Debt	5,199	5,236	(37)	
Deferred Tax Liabilities	1,371	1,352	19	
Investment Tax Credit	129	129	0	
Accum Provision for Pension & Related Benefits	274	264	10	
Asset Retirement Obligation	439	283	156	Primarily due to revalued ARO's to reflect updates in the estimated cash flows for planned pond closures of $162m as a result of the enactment of the Coal Combustion Residuals (CCR) Rule.
Regulatory Liabilities Non Current	942	931	12	
Derivative Liability	42	43	(1)	
Other Liabilities	217	269	(52)	Primarily due to reclassification of retainage related to CR7 project from long-term to short-term ($38m) and a decrease in post-retirement liability due to roll forward of participant census data and VEBA contributions ($21m).
Total Deferred Credits and Other Liabilities	3,414	3,271	142	
Equity	4,369	4,458	(89)	
Total Liabilities and Equity	**$ 13,812**	**$ 13,886**	**$ (74)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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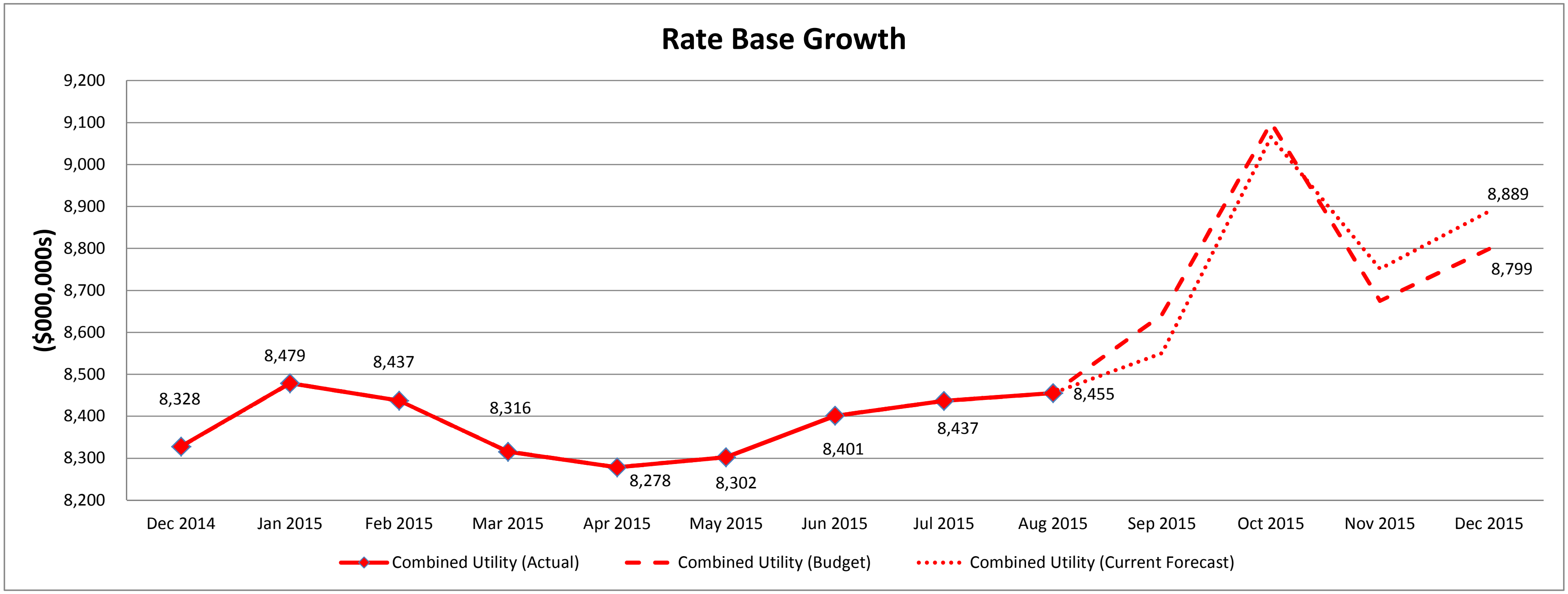

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Performance Report

September 2015

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Kentucky Regulated Dashboard — September 2015

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.17	1.54	1.11	1.27	1.41	1.03
Employee lost-time incidents	0	1	7	6	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,800	2,774	26,410	26,518	35,089	34,582
Utility EFOR	4.3%	5.9%	4.0%	5.9%	N/A	5.9%
Utility EAF	89.0%	92.6%	85.4%	86.8%	N/A	83.8%
Steam Fleet Commercial Availability	92.0%	92.0%	94.0%	92.0%	N/A	92.0%
Combined SAIFI	0.07	0.10	0.79	0.95	N/A	1.19
Combined SAIDI (minutes)	5.56	7.98	70.58	86.10	N/A	106.60
GwH Sales						
Residential	813	878	8,377	8,402	10,747	10,842
Commercial	669	650	5,981	6,037	7,848	7,916
Industrial	839	783	7,455	7,538	9,943	10,024
Municipals	153	163	1,445	1,456	1,879	1,890
Other	262	216	2,171	2,060	2,858	2,723
Off-System Sales	31	17	344	262	382	311
Total	2,767	2,707	25,773	25,755	33,658	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.06%			
Commercial			-0.99%			
Industrial			0.35%			
Municipal			-0.45%			
Other			-0.40%			
Total			-0.53%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	10.2%	10.3%	10.1%	9.1%	9.3%	8.9%
Electric Margins	$152	$158	$1,354	$1,338	$1,772	$1,774
Gas Margins	9	9	116	118	164	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$1	$3	$15	$40	$28	$47
ECR	35	50	454	473	583	569
Generation	8	13	71	121	136	149
Transmission	6	6	47	43	72	60
Electric Distribution	18	14	123	132	176	162
Gas Distribution	9	9	61	65	90	83
Customer Services	3	2	14	13	21	17
IT and Other	5	3	24	29	40	38
Total	$85	$99	$808	$915	$1,146	$1,125
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$37	$37	$349	$356	$475	$471
General Counsel & HR	3	4	26	30	39	40
Finance, IT, & Supply Chain	7	7	57	61	80	81
Burdens & Other Charges	13	14	116	132	152	176
Total	$60	$63	$548	$580	$745	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,469	3,568	3,469	3,568	3,542	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	15	9	N/A	9
NERC Possible Violations[4]	1	0	7	5	N/A	7

Variance Explanations

• Current month lower margins due to a combination of lower residential sales volumes resulting in $3 million lower retail electric base energy revenues and $3 million lower DSM revenues.

•YTD higher margins primarily due to higher ECR margins of $17 million resulting from greater spending levels and other adjustments, $3 million from the sale of excess generation, $3 million from lower cost of production margin expenses and $3 million from higher transmission revenues partially offset by $8 million lower retail electric base energy and demand revenues, $2 million lower DSM revenues and $2 million lower gas margins.

•Current month lower capital expenditures of $15 million primarily due to permitting delays or timing shifts at Trimble County and Ghent, respectively, related to environmental projects.

• YTD lower capital expenditures of $106 million due primarily to decreased spend and test energy budgeted but not used at Cane Run, delayed spending on several projects until later this year and planned timing shifts related to the Paddy's Run gas pipe line and Dix Dam leakage projects being moved to 2016.

• YTD lower O&M due to $18 million lower labor and burden costs, $4 million due to timing and other savings for maintenance outages, $3 million in lower materials and consulting costs, $3 million in lower uncollectible accounts and $3 million in lower other expenses.

• Fifteen environmental events have occurred YTD. Thirteen of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred during May at Ghent and a oil spill into the Ohio River at Mill Creek in June due to equipment failure.

Major Developments

• Green River Units 3 and 4 were officially retired just before midnight on September 30. This marks the completion of LKE's plan to retire 800 MW of coal-fired generation. Tyrone Station was retired in 2013, and Cane Run Units 4,5, and 6 were retired earlier this year. All associated operating and shutdown costs between July 1, 2015, and the plant's retirement have been recorded as a regulatory asset to be recovered over a 3-year period pursuant to KU's rate case order.

• LG&E priced $550 million and KU priced $500 million of first mortgage bonds on September 21. LG&E issued $300 million of 10-year bonds at 3.30% and $250 million of 30-year bonds at 4.375%. KU issued $250 million of 10-year bonds and $250 million of 30-year bonds at the same levels as LG&E. There was strong demand for the bonds and pricing was very tight to treasuries. Proceeds will be used to fund maturing first mortgage bonds and other general corporate purposes.

• On September 25, 2015, an electrician working for KBR, Inc. was fatally injured while performing work on the environmental air compliance project at KU's Ghent Generating Station. The worker was operating an aerial work platform and moved the platform into a position which pinned him between the platform's control panel and a beam approximately twenty-five feet off the ground. Work was immediately shut down at the site, and comprehensive safety meetings were initiated for all employees at the location. No co-workers witnessed the incident. The incident investigation is ongoing. As you know, we take our commitment to safety very seriously, and a loss like this is felt throughout our workforce and among our business partners.

• Brown Unit 3 and Ghent Unit 2 have started outages to facilitate the tie-in of their baghouse projects. Trimble County Unit 1 is also expected to start its outage in mid-October. These tie-in outages signify the final stages involved in the completion of the 2011 ECR Plans, with the exception of the Mill Creek 3 wet flue gas scrubber and baghouse project, which is progressing toward an April 2016 tie-in outage. Site prep and soil excavation for the Brown Solar project has also been completed.

• J.D. Power released its '2015 Gas Utility Residential Customer Satisfaction Study'. LG&E and Duke Energy tied for the second highest score (668) among 14 companies in the Midwest Midsize Segment. The results were particularly impressive in light of our base rate case and the potentially disruptive construction activity associated with our replacement programs.

Significant Future Events

• The discovery phase continues for the Virginia rate case with an informal hearing scheduled for December 14, 2015.

• Construction of the Brown Solar project is expected to take place over the next six months with mobilization beginning in November. The facility is expected to be commercially operational by late spring of 2016.

[1] Full year forecast amount shown represents target.
[2] Excludes goodwill and other purchase accounting adjustments.
[3] Net of cost recovery mechanisms.
[4] The possible violation issues for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget and Forecast (Month) — September 2015

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 239	$ 253	$ (14)	See "Electric Margin" explanation below.	$ 239	$ 238	$ 1	
Gas Revenues	12	14	(1)		12	14	(2)	
Total Revenues	251	267	(16)		251	252	(1)	
Cost of Sales:								
Fuel Electric Costs	69	76	7	See "Electric Margin" explanation below.	69	76	7	Due to lower energy volumes as a result of milder than expected weather.
Gas Supply Expenses	4	4	1		4	5	1	
Purchased Power	5	5	0		5	5	(0)	
Other Electric Cost	12	14	1		12	12	(0)	
Total Cost of Sales	90	99	9		90	97	7	
Gross Margin:								
Electric Margin	152	158	(6)	Lower margins due to a combination of lower residential sales volumes resulting in $3 million lower retail electric base energy revenues and $3 million lower DSM revenues.	152	145	7	Margin monthly forecast included load and weather risk of $13m that was not fully utilized as variance to budget was ($6m).
Gas Margin	9	9	(1)		9	9	(1)	
Total Gross Margin	161	167	(6)		161	154	7	
Operating Expenses:								
O&M	60	63	3		60	59	(1)	
Depreciation & Amortization	29	30	1		29	29	1	
Taxes, Other than Income	4	5	0		4	5	0	
Total Operating Expenses	93	97	4		93	93	(0)	
Other income (expense)	(1)	(0)	(0)		(1)	(1)	(0)	
EBIT	68	70	(2)		68	61	6	
Interest Expense	15	15	0		15	15	0	
Income from Ongoing Operations before income taxes	53	55	(3)		53	47	6	
Income Tax Expense	20	21	1		20	18	(3)	
Net Income (loss) from ongoing operations	**33**	**35**	**$ (2)**		**$ 33**	**29**	**$ 4**	
Non Operating Income	-	-	-		-	-	-	
Discontinued Operations	0	(0)	0		0	0	0	
Net Income (loss)	$ 33	$ 35	$ (2)		$ 33	$ 29	$ 4	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 30	$ 32	$ (2)		$ 30	$ 27	$ 4	
Earnings Per Share	$ 0.04	$ 0.05	$ (0.00)		$ 0.04	$ 0.04	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — September 2015

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,193	$ 2,250	$ (58)	Due to lower prices driven by mild weather and difference in budgeted distribution of rate case revenue.
Gas Revenues	224	240	(16)	See Gas Supply Expenses explanation below.
Total Revenues	2,417	2,491	(73)	
Cost of Sales:				
Fuel Electric Costs	699	750	51	Due to a combination of lower volumes for coal and lower commodity costs for natural gas.
Gas Supply Expenses	109	122	14	Due to lower net purchases of $22 million, timing of net exchange gas of $5 million and timing partially offset by less gas to storage activity of $13 million.
Purchased Power	41	47	6	
Other Electric Cost	99	115	16	Due to lower ECR expense of $9 million, scrubber reactant expense of $6 million and DSM expense of $2 million.
Total Cost of Sales	948	1,034	87	
Gross Margin:				
Electric Margin	1,354	1,338	16	Primarily due to higher ECR margins of $17 million resulting from greater spending levels and other adjustments, $3 million from the sale of excess generation, $3 million from lower cost of production margin expenses and $3 million from higher transmission revenues partially offset by $8 million lower retail electric base energy and demand revenues and $2 million lower DSM revenues.
Gas Margin	116	118	(2)	
Total Gross Margin	1,470	1,456	14	
Operating Expenses:				
O&M	548	580	32	Lower O&M due to $18 million lower labor and burden costs, $4 million due to timing and other savings for maintenance outages, $3 million in lower materials and consulting costs, $3 million in lower uncollectible accounts and $3 million in lower other expenses.
Depreciation & Amortization	259	267	8	Lower depreciation primarily due to the timing of retirement and in service dates related to Cane Run units as well as other project completion updates.
Taxes, Other than Income	40	42	2	
Total Operating Expenses	847	888	41	
Other income (expense)	(4)	(5)	1	
EBIT	619	563	56	
Interest Expense	128	131	3	
Income from Ongoing Operations before income taxes	491	432	59	
Income Tax Expense	186	163	(23)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**305**	**269**	**$ 36**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 297	$ 268	$ 29	
KY Regulated Financing Costs	(25)	$ (25)	(0)	
KY Regulated Net Income	$ 272	$ 243	$ 29	
Earnings Per Share	$ 0.41	$ 0.36	$ 0.05	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget — September 2015

($ Millions)

	Full Year				Full Year			
	Q3 Forecast	Q2 Forecast	Variance	Comments	Q3 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,873	$ 2,941	$ (68)	Due to lower fuel cost recoveries as shown below, along with lower than budgeted base energy revenues primarily during this summer. Remaining forecast also includes potential load and weather uncertainty.	$ 2,873	$ 2,976	$ (103)	Due to lower fuel cost recoveries as shown below, along with a difference in the budgeted distribution of rate case revenue versus actual tariffs for demand and energy revenues. Lastly, the forecast also includes potential load and weather uncertainty.
Gas Revenues	323	328	(5)		323	340	(17)	See Gas Supply Expense explanation below.
Total Revenues	3,196	3,269	(72)		3,196	3,317	(120)	
Cost of Sales:								
Fuel Electric Costs	911	960	49	Due to a combination of lower volumes for coal and lower commodity costs for natural gas.	911	980	69	Due to a combination of lower volumes for coal and lower commodity costs for natural gas.
Gas Supply Expenses	160	164	4		160	175	16	Due to lower GSC of $18 million partially offset by higher GLT expense of $3 million.
Purchased Power	54	57	3		54	66	12	Lower purchased power due to mild weather.
Other Electric Cost	137	143	6		137	156	19	Due to lower ECR expense of $12 million and scrubber reactant expense of $7 million.
Total Cost of Sales	1,261	1,323	62		1,261	1,377	116	
Gross Margin:								
Electric Margin	1,772	1,781	(10)	Primarily related to lower Electric Revenues. See explanation above.	1,772	1,774	(3)	
Gas Margin	164	164	(0)		164	165	(1)	
Total Gross Margin	1,935	1,945	(10)		1,935	1,939	(4)	
Operating Expenses:								
O&M	745	750	5		745	767	22	Lower O&M due to $15 million lower labor and burden costs, $6 million due to timing and other savings for maintenance outages and $7 million in lower other expenses partially offset by $7 million in higher materials and consulting costs.
Depreciation & Amortization	345	350	5		345	356	11	Due to the timing of retirement and in service dates related to Cane Run units and other project completion updates.
Taxes, Other than Income	54	54	0		54	55	2	
Total Operating Expenses	1,144	1,154	9		1,144	1,179	35	
Other income (expense)	(5)	(4)	(1)		(5)	(6)	1	
EBIT	786	788	(2)		786	754	32	
Interest Expense	183	184	1		183	186	4	
Income from Ongoing Operations before income taxes	603	604	(1)		603	568	35	
Income Tax Expense	228	229	1		228	215	(14)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**375**	**$ 375**	**$ 0**		**$ 375**	**$ 353**	**$ 22**	
Non Operating Income	(12)	(8)	(4)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.	(12)	-	(12)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	0	0		0	(0)	0	
Net Income (loss)	$ 363	$ 367	$ (3)		$ 363	$ 353	$ 10	
KY Regulated Financing Costs	(33)	(33)	-		(33)	(33)	-	
KY Regulated Net Income	$ 330	$ 333	$ (3)		$ 330	$ 320	$ 10	
Earnings Per Share	$ 0.49	$ 0.49	$ 0.00		$ 0.49	$ 0.47	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — September 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ (6)						$ (9)
Energy Volumes (a)	2,735,689	2,689,469	46,220		$ (1.2)		25,429,106	25,492,815	(63,709)		$ (1.9)	
Energy Prices (a)					$ (4.5)						$ (13.7)	
Customer Charges (Avg. Customers)	946,118	957,600	(11,482)		$ (0.4)		944,823	955,932	(11,109)		(1.5)	
Demand Charges (b)	$ 50	$ 49			$ 0.4		391	383			7.9	
ECR:						$ (0)						$ 17
Average Rate Base	$ 2,007	$ 2,030	$ (23)	10.23%	$ (0.2)		$ 1,864	$ 1,845	$ 19	10.16%	$ 1.3	
Cost of Capital	10.29%	10.23%	0.06%	$ 2,007	$ 0.1		10.31%	10.16%	0.15%	$ 1,864	1.9	
Jurisdictional Factor	92.32%	91.68%	0.64%	$ 2,007	$ 0.1		90.28%	90.62%	-0.34%	$ 1,864	(0.5)	
Other					$ (0.1)						14.6	
DSM:						$ (3)						$ (2)
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.5	$ 0.4			$ 0.0	
Lost Sales	0.2	1.1			$ (0.8)		9.1	9.5			$ (0.4)	
Incentive	0.1	0.1			$ 0.0		0.7	0.8			$ (0.1)	
Balancing Adjustment	(1.9)	-			$ (1.9)		(1.9)	-			$ (1.9)	
Net Fuel Recovery	$ 0.8	$ (0.3)				$ 1	$ (3.2)	$ (3.3)				$ 0
Purchase Power Demand	(2.9)	(3.0)				$ 0	(22.8)	(24.1)				$ 1
Transmission	1.0	0.7				$ 0	8.6	6.0				$ 3
Other	(0.3)	(1.3)				$ 1	(10.2)	(13.2)				$ 3
Retail Margin Variance						$ (6)						$ 13
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ (6)						$ 16

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 43	813,210	$ 53.14	$ 47	877,669	$ 53.18	($3.5)	($3.4)	($0.0)
Commercial	21	668,806	30.97	22	649,928	33.24	($0.9)	$0.6	($1.5)
Industrial	6	839,220	7.71	8	782,779	9.87	($1.3)	$0.6	($1.8)
Municipals	1	152,734	4.36	1	162,695	5.22	($0.2)	($0.1)	($0.1)
Other	6	261,717	21.31	5	216,397	25.20	$0.1	$1.1	($1.0)
Native Load Total	**$ 77**	**2,735,689**	**$ 28.01**	**$ 82**	**2,689,469**	**$ 30.60**	**($5.7)**	**($1.2)**	**($4.5)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 420	8,376,839	$ 50.19	$ 422	8,402,015	$ 50.27	($1.9)	($1.5)	($0.4)
Commercial	186	5,981,183	31.02	193	6,036,993	32.00	($7.7)	($1.8)	($5.9)
Industrial	65	7,455,124	8.68	70	7,537,350	9.29	($5.3)	($0.8)	($4.6)
Municipals	7	1,445,259	4.93	8	1,455,232	5.22	($0.5)	($0.1)	($0.4)
Other	49	2,170,700	22.64	49	2,061,224	23.96	($0.2)	$2.2	($2.4)
Native Load Total	**$ 727**	**25,429,106**	**$ 28.59**	**$ 743**	**25,492,815**	**$ 29.13**	**($15.6)**	**($1.9)**	**($13.7)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	15	18	(2)	127	129	(2)
Industrial	22	20	2	161	155	5
Municipals	5	5	(0)	49	47	2
Other	8	7	1	55	52	3
Native Load Total	**50**	**49**	**0**	**391**	**383**	**8**

Weather - Avg. Hourly Temperature [1]	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	-	-	-	41	3	8%
(°F) Lexington Heating Season	-	-	-	39	3	9%
(°F) Louisville Cooling Season	72	2	3%	74	1	1%
(°F) Lexington Cooling Season	70	2	3%	72	0	1%

[1] Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — September 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 45**	**$ 46**		**$ (0)**
Gas Supply Costs								
Gas Supply Costs	(3)	(4)	$ 1		(102)	(117)	15	
GSC Revenue	3	4	$ (1)		102	117	(15)	
Net Gas Supply Costs				**0**				**$ 0**
Retail Gas (a)	**2**	**3**		**(0)**	**63**	**62**		**$ 1**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**$ -**
DSM	**(0)**	**0**		**(0)**	**0**	**0**		**$ (0)**
GLT	**1**	**1**		**0**	**9**	**8**		**$ 0**
WNA	**(0)**	**-**		**(0)**	**(3)**	**-**		**$ (3)**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**$ 0**
Gas Margin Variance				**$ (1)**				**$ (2)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	368,185	$ 2.86	$ 1	470,582	$ 2.79	($0.3)	($0.3)	$0.0
Commercial	0	249,507	1.98	1	238,381	2.21	($0.0)	$0.0	($0.1)
Industrial	0	94,982	1.69	0	102,688	1.71	($0.0)	($0.0)	($0.0)
Public Authority	0	29,134	1.79	0	40,452	2.16	($0.0)	($0.0)	($0.0)
Transportation	0	888,026	0.47	0	770,255	0.46	$0.1	$0.1	$0.0
Interdepartmental	0	20,696	14.83	0	132,967	3.51	($0.2)	($0.4)	$0.2
Ultimate Consumer	$ 2	1,650,530	$ 1.51	$ 3	1,755,325	$ 1.67	($0.4)	($0.6)	$0.2

YTD

	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 38	14,285,580	$ 2.66	$ 37	13,964,654	$ 2.66	$1	$ 1	$ 0
Commercial	14	6,723,550	2.05	13	6,278,006	2.11	$1	$ 1	$ (0)
Industrial	2	1,048,343	1.86	2	1,031,960	1.83	$0	$ 0	$ 0
Public Authority	2	979,400	1.99	2	1,039,080	2.07	($0)	$ (0)	$ (0)
Transportation	5	10,355,218	0.46	4	8,201,016	0.44	$1	$1	$0
Interdepartmental	3	296,277	10.02	4	1,406,047	2.89	($1)	($3)	$2
Ultimate Consumer	$ 63	33,688,368	$ 1.88	$ 62	31,920,763	$ 1.94	$1	($1)	$2

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($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 16	$ 16	$ (0)	$ 0	$ (0)	$ (0)	$ (2)		$ 2
Project Engineering	0	0	0	0		0	(0)		0
Transmission	2	2	0	0		(0)	0		0
Energy Supply and Analysis	1	1	0	0		0	(0)		0
Generation Services	1	1	0	(0)		0	(0)		0
Electric Distribution	6	6	0	0		(0)	0	0	0
Gas Distribution	3	3	(0)	0		(0)	(0)	0	(0)
Safety and Security	0	0	(0)	0		(0)	(0)	0	0
Customer Services	8	8	(0)	0		0	0	(0)	(0)
Chief Operations Officer	**37**	**37**	**1**	**1**	**(0)**	**(0)**	**(2)**	**(0)**	**2**
General Counsel	3	4	1	0		1	0		(0)
Human Resources	1	1	0	0		(0)	0		0
General Counsel & HR	**3**	**4**	**1**	**0**		**1**	**0**		**(0)**
Information Technology	5	5	0	0		(0)	(0)		0
Supply Chain	0	0	0	0		0	0		(0)
Finance	2	2	(0)	0		0	0		(0)
Chief Financial Officer	**7**	**7**	**0**	**1**		**(0)**	**(0)**		**0**
Corporate	**13**	**14**	**1**	**2**		**(0)**	**(0)**	**(0)**	**(1)**
O&M Total MTD	**$ 60**	**$ 63**	**$ 3**	**$ 4**	**$ (0)**	**$ 0**	**$ (2)**	**$ (0)**	**$ 1**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 166	$ 169	$ 3	$ 0	4	$ (1)	$ 1		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	23	22	(1)	(0)		(1)	1		0
Energy Supply and Analysis	6	7	0	0		0	0		0
Generation Services	9	10	1	0		1	(0)		0
Electric Distribution	55	54	(0)	(0)		0	0	0	(0)
Gas Distribution	25	24	(0)	0		(0)	(0)	(0)	(1)
Safety and Security	3	3	0	0		(0)	0	0	(0)
Customer Services	61	66	5	1		2	1	3	(1)
Chief Operations Officer	**$ 349**	**$ 356**	**7**	**1**	**4**	**0**	**2**	**3**	**(2)**
General Counsel	21	25	3	0		2	0		1
Human Resources	5	6	1	0		0	(0)		0
General Counsel & HR	**$ 26**	**$ 30**	**4**	**1**		**2**	**(0)**		**1**
Information Technology	40	44	3	3		(0)	(0)		1
Supply Chain	3	3	0	(0)		(0)	0		0
Finance	14	15	1	0		0	0		0
Chief Financial Officer	**$ 57**	**$ 61**	**4**	**3**		**(0)**	**(0)**		**2**
Corporate	**$ 116**	**$ 132**	**16**	**13**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 548**	**$ 580**	**$ 32**	**$ 18**	**$ 4**	**$ 2**	**$ 1**	**$ 3**	**$ 3**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 226	$ 225	$ (1)	$ (3)	$ 6	$ (7)	$ 0		$ 3
Project Engineering	1	1	0	0		(0)	(0)		0
Transmission	30	29	(1)	(1)		(1)	1		0
Energy Supply and Analysis	9	9	(0)	(0)		(0)	0		0
Generation Services	13	14	0	(0)		1	0		(0)
Electric Distribution	72	70	(2)	(1)		(1)	0	0	(0)
Gas Distribution	35	33	(1)	(0)		(0)	0	(0)	(0)
Safety and Security	4	4	0	0		(0)	(0)	0	0
Customer Services	86	87	1	(1)		1	1	1	(1)
Chief Operations Officer	**$ 475**	**$ 471**	**(4)**	**(6)**	**6**	**(8)**	**2**	**1**	**2**
General Counsel	32	33	1	(0)		1	(0)		0
Human Resources	7	7	0	0		0	0		0
General Counsel & HR	**$ 39**	**$ 40**	**1**	**(0)**		**1**	**(0)**		**0**
Information Technology	56	58	2	2		(1)	(0)		1
Supply Chain	4	4	(0)	(0)		0	0		0
Finance	20	20	(0)	(1)		0	0		0
Chief Financial Officer	**$ 80**	**$ 81**	**1**	**1**		**(1)**	**(0)**		**1**
Corporate	**$ 152**	**$ 176**	**24**	**20**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 745**	**$ 767**	**$ 22**	**$ 15**	**$ 6**	**$ (8)**	**$ 2**	**$ 1**	**$ 7**

Note: Schedules may not sum due to rounding.

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Financing Activities — September 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 923.9	$ 0.0	$ 923.9	$ 923.9	$ -	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	(0.0)	923.9	923.9	(0.0)	923.9	923.9	(0.1)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ 0.0**	**$ 923.9**	**$ 923.9**	**$ (0.0)**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 7.7**	**$ 10.3**	**$ 2.6**	**$ 10.4**	**$ 13.8**	**$ 3.4**
Rate	**1.12%**	**1.49%**	**0.37%**	**1.10%**	**1.48%**	**0.37%**	**1.12%**	**1.12%**	**1.12%**
FMB/Sr Nts [1]									
Beg Bal	$ 3,643.9	$ 3,643.9	$ 0.0	$ 3,642.7	$ 3,642.7	$ -	$ 3,642.7	$ 3,642.7	$ -
End Bal	4,693.4	3,644.0	(1,049.3)	4,693.4	3,644.0	(1,049.3)	3,793.7	3,794.4	0.7
Ave Bal	**$ 4,168.6**	**$ 3,644.0**	**$ (524.7)**	**$ 4,168.0**	**$ 3,643.3**	**$ (524.7)**	**$ 3,756.1**	**$ 3,756.1**	**$ -**
Interest Exp	**$ 11.9**	**$ 11.5**	**$ (0.4)**	**$ 103.8**	**$ 103.4**	**$ (0.4)**	**$ 147.9**	**$ 148.3**	**$ 0.4**
Rate	**3.42%**	**3.78%**	**0.37%**	**3.28%**	**3.74%**	**0.46%**	**3.42%**	**3.42%**	**3.42%**
Short-term Debt									
Beg Bal	$ 631.6	$ 668.6	$ 37.0	$ 615.4	$ 615.4	$ -	$ 615.4	$ 615.4	$ -
End Bal	137.3	732.8	595.5	137.3	732.8	595.5	715.2	662.0	(53.3)
Ave Bal	**$ 384.5**	**$ 700.7**	**$ 316.3**	**$ 376.4**	**$ 674.1**	**$ 297.7**	**$ 553.5**	**$ 633.9**	**$ 80.4**
Interest Exp	**$ 0.4**	**$ 0.6**	**$ 0.2**	**$ 3.4**	**$ 5.0**	**$ 1.6**	**$ 3.4**	**$ 6.0**	**$ 2.6**
Rate	**1.13%**	**0.95%**	**-0.18%**	**1.20%**	**0.98%**	**-0.22%**	**1.13%**	**1.13%**	**1.13%**
Total End Bal	**$ 5,754.6**	**$ 5,300.7**	**$ (453.8)**	**$ 5,754.6**	**$ 5,300.7**	**$ (453.8)**	**$ 5,432.9**	**$ 5,380.2**	**$ (52.7)**
Total Average Bal	**$ 5,477.0**	**$ 5,268.6**	**$ (208.4)**	**$ 5,468.3**	**$ 5,241.4**	**$ (226.9)**	**$ 5,233.6**	**$ 5,314.0**	**$ 80.4**
Total Expense Excl I/C [2]	**$ 14.5**	**$ 14.6**	**$ 0.1**	**$ 128.0**	**$ 131.4**	**$ 3.4**	**$ 182.6**	**$ 186.3**	**$ 3.7**
Rate	**3.19%**	**3.33%**	**0.14%**	**3.09%**	**3.31%**	**0.22%**	**3.19%**	**3.19%**	**3.19%**

[1] Include FMBs maturing in November 2015 $900m.

[2] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 137		$ 163
LG&E	500	-		500
KU	598	-	$ 198	400
TOTAL	$ 1,398	$ 137	$ 198	$ 1,063

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	28.1%	-5%	25.8%	-7%
FFO to Debt - KU	24.0%	-1%	22.6%	-1%
Debt to EBITDA - LG&E [2]	3.29	-0.20	3.60	0.02
Debt to EBITDA - KU [2]	3.52	-0.32	3.62	-0.08
Debt to Capitalization - LG&E [3]	50.5%	3%	47.0%	0%
Debt to Capitalization - KU [3]	49.1%	2%	47.0%	0%

[2] Actuals represent a trailing 12 months

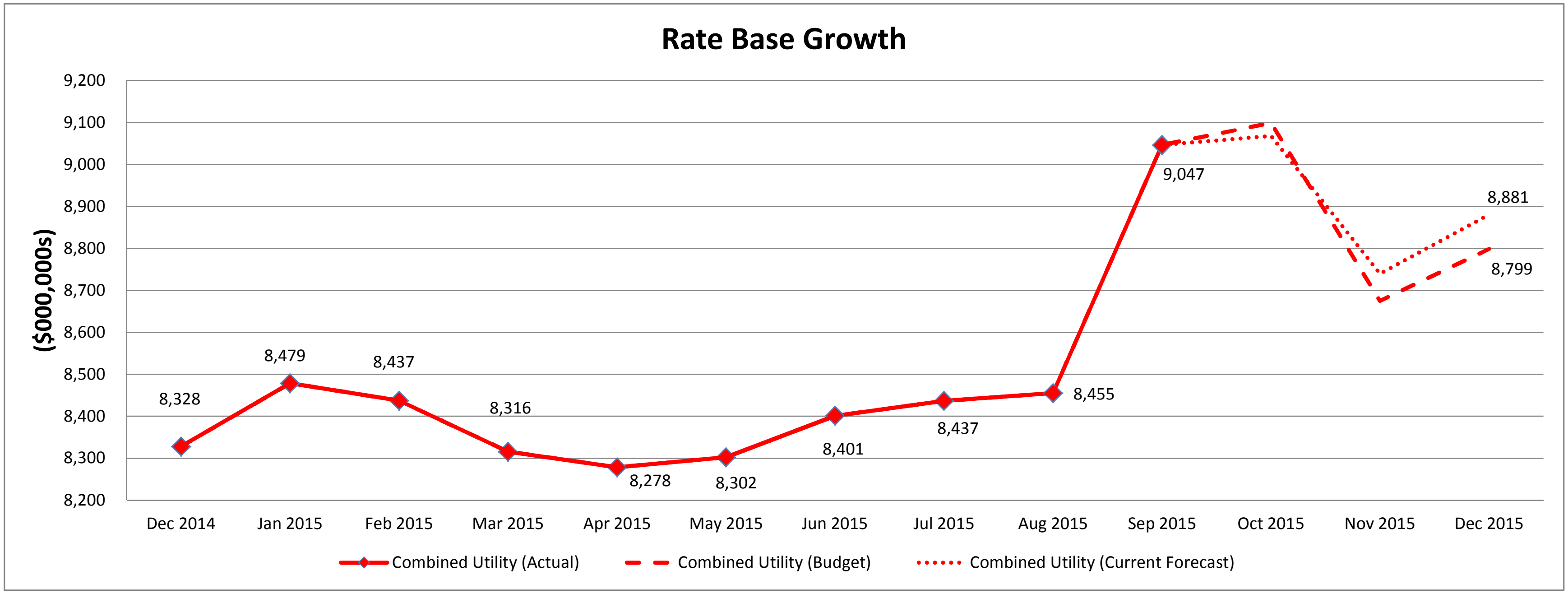
[3] Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet — September 2015

($ Millions)

	9/30/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 455	$ 16	$ 438	Primarily due to earlier than assumed issuance of first mortgage bonds.
Accounts Receivable (Trade)	381	409	(28)	
Inventory	260	269	(9)	
Deferred Income Taxes	68	16	52	Due to NOL utilization during the 1st half of 2016 of $41m, an intercompany transfer related to allocations from PPL of $5m and increase in regulatory asset/liability balances associated with billing mechanisms of $4m.
Regulatory Assets Current	27	39	(12)	
Prepayments and other current assets	41	184	(142)	Primarily related to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	1,232	933	299	
Property, Plant, and Equipment	11,226	11,104	122	
Intangible Assets	136	136	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	685	657	27	
Goodwill	997	997	-	
Other Long-term Assets	100	105	(5)	
Total Assets	**$ 14,377**	**$ 13,934**	**$ 444**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 285	$ 353	$ (69)	Decreases in project engineering accruals ($65m) and timing of other payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	51	52	(1)	
Derivative Liability	5	71	(66)	Due to settlement of forward starting swaps with PPL.
Accrued Taxes	36	228	(193)	Due to income tax settlement (see Prepayments and other current assets explanation above).
Regulatory Liabilities Current	31	12	19	Higher balance primarily due to timing related DSM programs of $10m and over-recovery of fuel costs related to FAC of $8m.
Other Current Liabilities	200	182	18	Primarily related to reclassification of ARO's from noncurrent to current liability of $15m.
Total Current Liabilities	609	899	(290)	
Debt - Affiliated Company	62	44	18	
Debt [(1)]	5,692	5,257	435	Primarily due to earlier than assumed issuance of first mortgage bonds.
Total Debt	5,755	5,301	454	
Deferred Tax Liabilities	1,489	1,407	82	
Investment Tax Credit	128	128	0	
Accum Provision for Pension & Related Benefits	275	265	9	
Asset Retirement Obligation	488	284	204	Due to revaluation of ARO's to reflect updates in the estimated cash flows for ash and environmental ponds $220m primarily related to the enactment of the Coal Combustion Residuals (CCR) Rule partially offset by a reclassification of ARO from non-current to current liabilities of ($15m).
Regulatory Liabilities Non Current	937	924	13	
Derivative Liability	45	43	1	
Other Liabilities	214	266	(52)	Primarily due to reclassification of retainage related to CR7 project from long-term to short-term ($38m) and a decrease in post-retirement liability due to roll forward of participant census data and VEBA contributions ($24m).
Total Deferred Credits and Other Liabilities	3,576	3,319	257	
Equity	4,437	4,415	23	
Total Liabilities and Equity	**$ 14,377**	**$ 13,934**	**$ 444**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,328
8,479
8,437
8,316
8,278
8,302
8,401
8,437
8,455
9,047
8,881
8,799
Dec 2014
Jan 2015
Feb 2015
Mar 2015
Apr 2015
May 2015
Jun 2015
Jul 2015
Aug 2015
Sep 2015
Oct 2015
Nov 2015
Dec 2015
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

YTD	Actual	Budget	Variance	Comments
Net Income	297	268	29	Due to higher gross margin and lower O&M partially offset by higher taxes. See Income Statement.
Depreciation	304	309	(6)	
Deferred Income Taxes	199	160	39	Primarily due to the impact of taking bonus depreciation at KU offset by a change of NOL utilization to NOL addition.
Other Balance Sheet Movements	75	176	(101)	Primarily related to settlement of interest rate swaps.
Funds From Operations	**875**	**914**	**(39)**	
Changes in accounts receivables	18	(5)	23	Primarily due to a decrease in unbilled revenue and customer accounts receivable related to lower volumes driven by seasonality.
Changes in inventories	43	40	3	
Change in Accounts Payable	(41)	(53)	12	
Change in Working Capital	**20**	**(18)**	**38**	
Operating Cash flow	**895**	**896**	**(2)**	
Capex	(928)	(915)	(13)	
Other Investing	7	0	7	Due to proceeds from key man life issuance.
Loans to Affiliates	0	0	0	
Investing Cash flow	**(921)**	**(915)**	**(7)**	
Dividends	(157)	(160)	3	
Equity Infusion	55	56	(1)	
Net Borrowings	562	117	444	Primarily due to earlier than assumed issuance of first mortgage bonds.
Other	0	0	0	
Financing Cash flow	**460**	**13**	**446**	
Net increase (decrease) in cash	**434**	**(5)**	**438**	

KU and LG&E Combined

Reconciliation of Allowed Return to

12 months ended Sep-2015 Regulatory Return

and ROE from Ongoing Operations

Allowed Return [(1)]		10.23%	
Adjustments (net of tax):			
Change in capitalization - non mechanism	-2.13%		Growth in non-mechanism capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.25%		Additional borrowings offset by favorable rates
Change in margins	3.27%		Primarily new rates based on last rate cases
Change in allowed expenses	-1.60%		Inflationary increases
		-0.72%	
Actual Regulated ROE		9.51%	

(1) Based on the most recent base rate filings with test years ending 6/30/16 KPSC, 12/31/13 FERC, 12/31/12 VA.

Note: The allowed return is a blended rate of the previous authorized ROE of 10.25% before 7/1/15 and from the settlement for TYE 6/30/16 which did not provide a specific return on equity with respect to base rates; however, the average customer's monthly bill will reflect an authorized 10 percent return on equity investment related to the environmental cost recovery mechanism and the gas line tracker mechanism.

Performance Report

October 2015

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Kentucky Regulated Dashboard

October 2015

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.82	0.54	1.07	1.18	1.41	1.03
Employee lost-time incidents	0	0	7	6	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,474	2,476	28,884	28,994	34,956	34,582
Utility EFOR	2.1%	5.9%	3.8%	5.9%	N/A	5.9%
Utility EAF	68.1%	63.9%	83.6%	84.5%	N/A	83.8%
Steam Fleet Commercial Availability	97.3%	92.0%	94.3%	92.0%	N/A	92.0%
Combined SAIFI	0.07	0.10	0.86	1.05	N/A	1.19
Combined SAIDI (minutes)	4.92	8.16	75.51	94.26	N/A	106.60
GwH Sales						
Residential	602	702	8,979	9,104	10,747	10,842
Commercial	606	617	6,587	6,654	7,848	7,916
Industrial	829	804	8,284	8,342	9,943	10,024
Municipals	134	141	1,579	1,597	1,879	1,890
Other	235	213	2,406	2,273	2,858	2,723
Off-System Sales	18	2	362	264	382	311
Total	2,424	2,479	28,197	28,234	33,658	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-0.91%			
Commercial			-0.22%			
Industrial			-0.13%			
Municipal			-0.11%			
Other			-0.01%			
Total			-0.39%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	5.6%	5.4%	9.6%	8.7%	9.3%	8.9%
Electric Margins	$134	$139	$1,488	$1,478	$1,771	$1,774
Gas Margins	12	11	128	129	164	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$2	$2	$17	$42	$28	$47
ECR	43	40	496	513	583	569
Generation	17	16	88	137	136	149
Transmission	9	6	56	49	72	60
Electric Distribution	17	11	140	143	176	162
Gas Distribution	9	9	70	73	90	83
Customer Services	1	2	15	14	21	17
IT and Other	5	3	29	32	40	38
Total	$102	$89	$911	$1,004	$1,146	$1,125
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$45	$45	$393	$402	$475	$471
General Counsel & HR	3	3	29	33	39	40
Finance, IT, & Supply Chain	7	7	64	68	80	81
Burdens & Other Charges	11	14	127	147	152	176
Total	$66	$70	$614	$650	$745	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,466	3,567	3,466	3,567	3,519	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	15	9	N/A	9
NERC Possible Violations[4]	0	2	7	7	N/A	7

Variance Explanations

• YTD higher margins primarily due to higher ECR margins of $18 million resulting from greater spending levels and other adjustments, $4 million from lower cost of production margin expenses, $3 million from the sale of excess generation and $3 million from higher transmission revenues partially offset by $16 million lower retail electric base service, energy and demand revenues and $3 million lower DSM revenues.

• Current month higher capital expenditures of $13 million primarily due to electric distribution projects related to new business, reliability and repair and replacement of equipment as well as other transmission and environmental projects.

• YTD lower capital expenditures of $93 million due primarily to decreased spend and test energy budgeted but not used at Cane Run and timing shifts related to the Paddy's Run gas pipe line, Dix Dam leakage project and environmental projects at Ghent and Trimble County. Remaining Q4 capital projections include increased spending as a result of earlier timing delays for several environmental, plant outage and system reliability projects that will bring overall spend levels closer to the original budget.

• YTD lower O&M due to $19 million lower labor and burden costs, inclusive of regulatory accounting changes from the KY rate case, $4 million due to timing and other savings for maintenance outages, $5 million in lower materials and consulting costs, $3 million in lower uncollectible accounts and $5 million in lower other expenses.

• Fifteen environmental events have occurred YTD. Thirteen of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred during May at Ghent and a oil spill into the Ohio River at Mill Creek in June due to equipment failure.

Major Developments

• LG&E and KU improved its position in the third quarter Residential Customer Satisfaction survey as it moved from third place to second place. LG&E and KU achieved a “top two box” score of 57 percent which represents its highest score since 2010. The Company's score also ranks only slightly below top performer MidAmerican's score of 60 percent.

• The Sixth Circuit Court of Appeals issued its opinion finding that the state tort claims (seeking compensatory damages) in the Cane Run lawsuit are not preempted by the Clean Air Act. As a result, this matter has been sent back to the United States District Court for further proceedings on those claims. We are evaluating the possibility of further appeals or going back to district court to challenge class certification.

•LG&E and KU have signed on to a proposed settlement among all parties in the dispute among MISO, SPP and other regional parties relating to power flows and other effects on neighboring transmission systems of MISO's Midwest and South interconnection practices. Pursuant to the settlement, MISO will agree to specified MW limits on such flows, compensate affected systems for certain flows in excess of such limits, and implement other coordination steps. The agreement initially covers a 2014-2021 period. Depending on actual MISO usage, LG&E and KU may receive approximately $6M in net present value of payments during the agreement's term, and also see a reduction in certain transmission planning/reliability uncertainties related to MISO's former practices. The settlement is subject to FERC approval.

•Chairman David Armstrong resigned from the KPSC in October 2015. Armstrong joined the KPSC in 2008, and had been serving beyond the June 30, 2015 expiration of his term. Governor Steve Beshear appointed Vice Chairman James Gardner to Chairman, and Commissioner Daniel Logsdon to Vice Chairman, respectively. Both appointments are subject to senate confirmation when the Kentucky General Assembly reconvenes in January 2016. A vacancy remains on the three-member Commission.

Significant Future Events

• Regarding its Virginia rate case, the Company is currently engaged in the discovery process and a settlement conference with VSCC Staff is scheduled for November 23, 2015. A public hearing has also been scheduled for December 14, 2015. Subject to regulatory review and approval, new rates would become effective April 1, 2016.

• Construction of the Brown Solar project is expected to take place over the next six months with mobilization beginning in November. The facility is expected to be commercially operational by late spring of 2016.

(1) Full year forecast amount shown represents target.
(2) Excludes goodwill and other purchase accounting adjustments.
(3) Net of cost recovery mechanisms.
(4) The possible violation issues for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget and Forecast (Month) — October 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Variance	Comments	MTD Actual	MTD Q3 Forecast	MTD Variance	Comments
Revenues:								
Electric Revenues	$ 206	$ 230	$ (24)	See "Electric Margin" explanation below.	$ 206	$ 218	$ (13)	Primarily due to lower energy volumes resulting from unfavorable weather.
Gas Revenues	17	18	(1)		17	20	(3)	
Total Revenues	223	248	(25)		223	238	(15)	
Cost of Sales:								
Fuel Electric Costs	56	71	15	See "Electric Margin" explanation below.	56	65	10	Primarily due to lower energy volumes resulting from unfavorable weather.
Gas Supply Expenses	5	7	2		5	9	4	
Purchased Power	5	7	2		5	5	(1)	
Other Electric Cost	11	13	2		11	11	0	
Total Cost of Sales	77	98	21		77	90	13	
Gross Margin:								
Electric Margin	134	139	(5)	Lower margins primarily due to lower residential sales volumes resulting in $6 million lower retail electric base energy and demand revenues partially offset by $1 million from lower cost of production margin expenses.	134	137	(3)	
Gas Margin	12	11	1		12	11	1	
Total Gross Margin	146	150	(4)		146	148	(2)	
Operating Expenses:								
O&M	66	70	4		66	68	2	
Depreciation & Amortization	28	30	1		28	29	0	
Taxes, Other than Income	5	5	0		5	5	0	
Total Operating Expenses	99	104	5		99	102	3	
Other income (expense)	(1)	(0)	(0)		(1)	0	(1)	
EBIT	47	46	1		47	47	0	
Interest Expense	18	18	0		18	18	0	
Income from Ongoing Operations before income taxes	29	27	1		29	29	(0)	
Income Tax Expense	11	10	(0)		11	11	0	
Net Income (loss) from ongoing operations	**18**	**17**	**$ 1**		**$ 18**	**18**	**$ (0)**	
Non Operating Income	-	-	-		-	-	-	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 18	$ 17	$ 1		$ 18	$ 18	$ (0)	
KY Regulated Financing Costs	(3)	(3)	0		(3)	(3)	(0)	
KY Regulated Net Income	$ 15	$ 14	$ 1		$ 15	$ 15	$ (0)	
Earnings Per Share	$ 0.02	$ 0.02	$ 0.00		$ 0.02	$ 0.02	$ (0.00)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) — October 2015

($ Millions)

	YTD Actual	YTD Budget	YTD Variance	Comments
Revenues:				
Electric Revenues	$ 2,398	$ 2,480	$ (82)	Due to lower prices driven by unfavorable weather, lower FAC revenues and a difference in budgeted distribution of rate case revenue.
Gas Revenues	242	258	(17)	See Gas Supply Expenses explanation below.
Total Revenues	2,640	2,739	(99)	
Cost of Sales:				
Fuel Electric Costs	755	821	66	Primarily due to lower commodity costs related to natural gas.
Gas Supply Expenses	114	130	16	Due to lower net purchases, timing of net exchange gas partially offset by less gas to storage activity.
Purchased Power	46	54	8	Lower purchased power due to mild weather.
Other Electric Cost	110	128	18	Due to lower ECR expense of $10 million, scrubber reactant expense of $7 million and DSM expense of $2 million.
Total Cost of Sales	1,025	1,133	108	
Gross Margin:				
Electric Margin	1,488	1,478	10	Primarily due to higher ECR margins of $18 million resulting from greater spending levels and other adjustments, $4 million from lower cost of production margin expenses, $3 million from the sale of excess generation and $3 million from higher transmission revenues partially offset by $16 million lower retail electric base service, energy and demand revenues and $3 million lower DSM revenues.
Gas Margin	128	129	(1)	
Total Gross Margin	1,616	1,606	9	
Operating Expenses:				
O&M	614	650	36	Due to $19 million lower labor and burden costs, $4 million due to timing and other savings for maintenance outages, $5 million in lower materials and consulting costs, $3 million in lower uncollectible accounts and $5 million in lower other expenses.
Depreciation & Amortization	288	296	9	Lower depreciation primarily due to the timing of retirement and in service dates related to Cane Run units as well as other project completion updates.
Taxes, Other than Income	45	46	2	
Total Operating Expenses	946	992	46	
Other income (expense)	(4)	(5)	1	
EBIT	665	609	57	
Interest Expense	146	150	4	
Income from Ongoing Operations before income taxes	519	459	60	
Income Tax Expense	196	173	(23)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**323**	**286**	**$ 37**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 315	$ 285	$ 29	
KY Regulated Financing Costs	(28)	$ (28)	(0)	
KY Regulated Net Income	$ 286	$ 257	$ 29	
Earnings Per Share	$ 0.44	$ 0.38	$ 0.05	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget — October 2015

($ Millions)

	Full Year				Full Year			
	Q3 Forecast	Q2 Forecast	Variance	Comments	Q3 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,873	$ 2,941	$ (68)	Due to lower fuel cost recoveries as shown below, along with lower than budgeted base energy revenues primarily during this summer. Remaining forecast also includes potential load and weather uncertainty.	$ 2,873	$ 2,976	$ (104)	Due to lower fuel cost recoveries as shown below, along with a difference in the budgeted distribution of rate case revenue versus actual tariffs for demand and energy revenues. Lastly, the forecast also includes potential load and weather uncertainty.
Gas Revenues	323	328	(5)		323	340	(17)	See Gas Supply Expense explanation below.
Total Revenues	3,196	3,269	(73)		3,196	3,317	(121)	
Cost of Sales:								
Fuel Electric Costs	911	960	49	Due to a combination of lower volumes for coal and lower commodity costs for natural gas.	911	980	69	Due to a combination of lower volumes for coal and lower commodity costs for natural gas.
Gas Supply Expenses	160	164	4		160	175	16	Due to lower GSC of $18 million partially offset by higher GLT expense of $3 million.
Purchased Power	54	57	3		54	66	12	Lower purchased power due to mild weather.
Other Electric Cost	137	143	6		137	156	19	Due to lower ECR expense of $12 million and scrubber reactant expense of $7 million.
Total Cost of Sales	1,261	1,323	62		1,261	1,377	116	
Gross Margin:								
Electric Margin	1,771	1,781	(10)	Primarily related to lower Electric Revenues. See explanation above.	1,771	1,774	(3)	
Gas Margin	164	164	(0)		164	165	(1)	
Total Gross Margin	1,935	1,945	(10)		1,935	1,939	(4)	
Operating Expenses:								
O&M	745	750	5		745	767	22	Lower O&M due to $15 million lower labor and burden costs, $6 million due to timing and other savings for maintenance outages and $7 million in lower other expenses partially offset by $7 million in higher materials and consulting costs.
Depreciation & Amortization	346	350	4		346	356	10	Due to the timing of retirement and in service dates related to Cane Run units and other project completion updates.
Taxes, Other than Income	54	54	0		54	55	2	
Total Operating Expenses	1,145	1,154	9		1,145	1,179	34	
Other income (expense)	(5)	(4)	(1)		(5)	(6)	1	
EBIT	785	788	(3)		785	754	30	
Interest Expense	182	184	2		182	186	5	
Income from Ongoing Operations before income taxes	603	604	(1)		603	568	35	
Income Tax Expense	228	229	1		228	215	(13)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**375**	**$ 375**	**$ 0**		**$ 375**	**$ 353**	**$ 22**	
Non Operating Income	(12)	(8)	(4)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.	(12)	-	(12)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	0	0		0	(0)	0	
Net Income (loss)	$ 363	$ 367	$ (4)		$ 363	$ 353	$ 10	
KY Regulated Financing Costs	(33)	(33)	-		(33)	(33)	-	
KY Regulated Net Income	$ 330	$ 333	$ (4)		$ 330	$ 320	$ 10	
Earnings Per Share	$ 0.49	$ 0.49	$ (0.01)		$ 0.49	$ 0.47	$ 0.01	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — October 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ (7)						$ (16)
Energy Volumes (a)	2,405,772	2,477,268	(71,496)		$ (4.9)		27,834,878	27,970,082	(135,205)		$ (6.5)	
Energy Prices (a)					$ (3.6)						$ (17.6)	
Customer Charges (Avg. Customers)	947,324	957,983	(10,659)		$ (0.5)		945,073	956,137	(11,064)		(1.9)	
Demand Charges (b)	$ 44	$ 42			$ 2.1		435	425			10.1	
ECR:						$ 1						$ 18
Average Rate Base	$ 2,033	$ 2,055	$ (22)	10.13%	$ (0.2)		$ 1,881	$ 1,866	$ 15	10.16%	$ 1.2	
Cost of Capital	10.24%	10.13%	0.11%	$ 2,033	$ 0.2		10.30%	10.16%	0.14%	$ 1,881	2.0	
Jurisdictional Factor	92.93%	89.88%	3.05%	$ 2,033	$ 0.5		90.57%	90.53%	0.04%	$ 1,881	0.1	
Other					$ 0.4						15.0	
DSM:						$ (1)						$ (3)
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.6	$ 0.5			$ 0.1	
Lost Sales	0.2	1.1			$ (0.8)		9.4	10.6			$ (1.2)	
Incentive	0.1	0.1			$ 0.0		0.8	0.9			$ (0.1)	
Balancing Adjustment	-	-			$ -		(1.9)	-			$ (1.9)	
Net Fuel Recovery	$ (0.3)	$ (0.9)				$ 1	$ (3.4)	$ (4.2)				$ 1
Purchase Power Demand	(3.5)	(3.0)				$ (0)	(26.2)	(27.1)				$ 1
Transmission	0.5	0.2				$ 0	9.0	6.3				$ 3
Other	(0.1)	(1.0)				$ 1	(10.3)	(14.2)				$ 4
Retail Margin Variance						$ (5)						$ 7
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ (5)						$ 10

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 32	601,738	$ 53.42	$ 38	702,436	$ 53.42	($5.4)	($5.4)	($0.0)
Commercial	18	606,417	30.38	20	616,679	32.72	($1.8)	($0.3)	($1.4)
Industrial	7	828,970	7.90	8	804,249	9.82	($1.3)	$0.2	($1.6)
Municipals	1	133,529	4.64	1	140,674	5.21	($0.1)	($0.0)	($0.1)
Other	5	235,119	22.85	5	213,229	25.06	$0.0	$0.6	($0.5)
Native Load Total	**$ 63**	**2,405,772**	**$ 26.23**	**$ 72**	**2,477,268**	**$ 28.93**	**($8.6)**	**($4.9)**	**($3.6)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 453	8,978,577	$ 50.41	$ 460	9,104,451	$ 50.51	($7.3)	($6.6)	($0.7)
Commercial	204	6,587,600	30.96	213	6,653,673	32.07	($9.4)	($2.1)	($7.3)
Industrial	71	8,284,094	8.60	78	8,341,600	9.34	($6.7)	($0.5)	($6.1)
Municipals	8	1,578,788	4.90	8	1,595,906	5.22	($0.6)	($0.1)	($0.5)
Other	55	2,405,819	22.66	55	2,274,452	24.06	($0.2)	$2.8	($3.0)
Native Load Total	**$ 790**	**27,834,878**	**$ 28.38**	**$ 814**	**27,970,082**	**$ 29.11**	**($24.2)**	**($6.5)**	**($17.6)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	14	13	0	141	143	(2)
Industrial	20	18	2	181	173	8
Municipals	4	5	(2)	52	52	0
Other	7	6	1	62	57	4
Native Load Total	**44**	**42**	**2**	**435**	**425**	**10**

Weather - Avg. Hourly Temperature [1]	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	-	-	-	41	3	8%
(°F) Lexington Heating Season	-	-	-	39	3	9%
(°F) Louisville Cooling Season	60	1	2%	72	1	1%
(°F) Lexington Cooling Season	58	1	2%	69	1	1%

[1] Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — October 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 51**	**$ 51**		**$ (0)**
Gas Supply Costs								
Gas Supply Costs	(4)	(7)	$ 2		(107)	(124)	17	
GSC Revenue	5	7	$ (2)		107	124	(17)	
Net Gas Supply Costs				**0**				**$ 0**
Retail Gas (a)	**4**	**5**		**(1)**	**67**	**67**		**$ 1**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**$ -**
DSM	**0**	**0**		**(0)**	**0**	**0**		**$ (0)**
GLT	**1**	**1**		**0**	**10**	**9**		**$ 0**
WNA	**2**	**-**		**2**	**(1)**	**-**		**$ (1)**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**$ 0**
Gas Margin Variance				**$ 1**				**$ (1)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 2	698,763	$ 2.87	$ 2	851,303	$ 2.79	($0.4)	($0.4)	$0.1
Commercial	1	399,617	1.99	1	430,688	2.21	($0.2)	($0.1)	($0.1)
Industrial	0	112,831	1.70	0	119,908	1.84	($0.0)	($0.0)	($0.0)
Public Authority	0	56,220	1.84	0	72,262	2.16	($0.1)	($0.0)	($0.0)
Transportation	0	1,291,758	0.38	1	1,125,758	0.47	($0.0)	$0.1	($0.1)
Interdepartmental	0	39,575	8.27	0	286,573	1.66	($0.1)	($0.4)	$0.3
Ultimate Consumer	$ 4	2,598,764	$ 1.51	$ 5	2,886,493	$ 1.63	($0.8)	($0.9)	$0.1

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 40	14,984,343	$ 2.67	$ 39	14,815,957	$ 2.66	$1	$ 0	$ 0
Commercial	15	7,123,167	2.05	14	6,708,694	2.11	$0	$ 1	$ (0)
Industrial	2	1,161,174	1.85	2	1,151,868	1.83	$0	$ 0	$ 0
Public Authority	2	1,035,620	1.98	2	1,111,342	2.08	($0)	$ (0)	$ (0)
Transportation	5	11,646,976	0.45	4	9,326,774	0.45	$1	$1	$0
Interdepartmental	3	335,852	9.81	5	1,692,621	2.68	($1)	($4)	$2
Ultimate Consumer	$ 67	36,287,132	$ 1.86	$ 67	34,807,256	$ 1.92	$1	($1)	$2

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 22	$ 24	$ 2	$ (1)	$ 4	$ 0	$ (0)		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	3	2	(0)	(0)		(0)	0		(0)
Energy Supply and Analysis	1	1	(0)	(0)		0	0		0
Generation Services	1	1	(0)	(0)		(0)	(0)		0
Electric Distribution	7	5	(1)	(0)		(1)	(0)	0	0
Gas Distribution	3	4	1	0		1	(0)	(0)	(0)
Safety and Security	0	0	(0)	(0)		0	0	0	0
Customer Services	7	7	(0)	(0)		0	0	0	(0)
Chief Operations Officer	**45**	**45**	**1**	**(2)**	**4**	**(0)**	**(0)**	**0**	**(1)**
General Counsel	2	2	(0)	(0)		(0)	(0)		0
Human Resources	1	1	0	(0)		0	0		(0)
General Counsel & HR	**3**	**3**	**(0)**	**(0)**		**0**	**(0)**		**(0)**
Information Technology	5	5	(0)	(0)		(0)	0		0
Supply Chain	0	0	(0)	(0)		0	(0)		0
Finance	2	2	0	(0)		0	0		0
Chief Financial Officer	**7**	**7**	**0**	**(0)**		**(0)**	**0**		**0**
Corporate	**11**	**14**	**3**	**3**		**0**	**0**	**(0)**	**0**
O&M Total MTD	**$ 66**	**$ 70**	**$ 4**	**$ 1**	**$ 4**	**$ (1)**	**$ 0**	**$ 0**	**$ (1)**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 188	$ 193	$ 5	$ (0)	8	$ (1)	$ 1		$ (3)
Project Engineering	0	1	0	0		(0)	(0)		0
Transmission	26	25	(1)	(0)		(2)	1		0
Energy Supply and Analysis	7	7	0	0		0	0		0
Generation Services	11	11	1	(0)		1	(0)		0
Electric Distribution	61	59	(2)	(0)		(1)	0	0	(0)
Gas Distribution	28	28	0	0		1	(0)	(0)	(1)
Safety and Security	3	4	0	(0)		(0)	0	0	0
Customer Services	69	73	5	0		2	1	3	(1)
Chief Operations Officer	**$ 393**	**$ 402**	**8**	**(1)**	**8**	**(0)**	**2**	**3**	**(4)**
General Counsel	24	27	3	0		2	(0)		1
Human Resources	5	6	1	0		0	(0)		0
General Counsel & HR	**$ 29**	**$ 33**	**4**	**1**		**2**	**(0)**		**1**
Information Technology	45	48	3	3		(1)	(0)		1
Supply Chain	3	3	(0)	(0)		0	0		0
Finance	16	17	1	(0)		0	0		1
Chief Financial Officer	**$ 64**	**$ 68**	**4**	**3**		**(1)**	**(0)**		**2**
Corporate	**$ 127**	**$ 147**	**19**	**16**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 614**	**$ 650**	**$ 36**	**$ 19**	**$ 8**	**$ 2**	**$ 1**	**$ 3**	**$ 3**

	Full Year								
	Forecast	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 226	$ 225	$ (1)	$ (3)	$ 6	$ (7)	$ 0		$ 3
Project Engineering	1	1	0	0		(0)	(0)		0
Transmission	30	29	(1)	(1)		(1)	1		0
Energy Supply and Analysis	9	9	(0)	(0)		(0)	0		0
Generation Services	13	14	0	(0)		1	0		(0)
Electric Distribution	72	70	(2)	(1)		(1)	0	0	(0)
Gas Distribution	35	33	(1)	(0)		(0)	0	(0)	(0)
Safety and Security	4	4	0	0		(0)	(0)	0	0
Customer Services	86	87	1	(1)		1	1	1	(1)
Chief Operations Officer	**$ 475**	**$ 471**	**(4)**	**(6)**	**6**	**(8)**	**2**	**1**	**2**
General Counsel	32	33	1	(0)		1	(0)		0
Human Resources	7	7	0	0		0	0		0
General Counsel & HR	**$ 39**	**$ 40**	**1**	**(0)**		**1**	**(0)**		**0**
Information Technology	56	58	2	2		(1)	(0)		1
Supply Chain	4	4	(0)	(0)		0	0		0
Finance	20	20	(0)	(1)		0	0		0
Chief Financial Officer	**$ 80**	**$ 81**	**1**	**1**		**(1)**	**(0)**		**1**
Corporate	**$ 152**	**$ 176**	**24**	**20**		**(0)**	**(0)**	**0**	**3**
O&M Total YTD	**$ 745**	**$ 767**	**$ 22**	**$ 15**	**$ 6**	**$ (8)**	**$ 2**	**$ 1**	**$ 7**

Note: Schedules may not sum due to rounding.

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Financing Activities — October 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	0.0	923.9	923.9	0.0	923.9	923.9	(0.1)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ 0.0**	**$ 923.9**	**$ 923.9**	**$ 0.0**	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 8.6**	**$ 11.5**	**$ 2.9**	**$ 10.4**	**$ 13.8**	**$ 3.4**
Rate	**1.09%**	**1.44%**	**0.36%**	**1.10%**	**1.47%**	**0.37%**	**1.09%**	**1.09%**	**1.09%**
FMB/Sr Nts (1)									
Beg Bal	$ 4,693.4	$ 3,644.0	$ (1,049.3)	$ 3,642.7	$ 3,642.7	$ -	$ 3,642.7	$ 3,642.7	$ -
End Bal	4,693.5	4,694.2	0.7	4,693.5	4,694.2	0.7	3,793.7	3,794.4	0.7
Ave Bal	**$ 4,693.4**	**$ 4,169.1**	**$ (524.3)**	**$ 4,168.1**	**$ 4,168.4**	**$ 0.3**	**$ 3,843.4**	**$ 3,756.1**	**$ (87.3)**
Interest Exp	**$ 15.0**	**$ 15.1**	**$ 0.1**	**$ 118.8**	**$ 118.6**	**$ (0.3)**	**$ 147.9**	**$ 148.3**	**$ 0.4**
Rate	**3.72%**	**4.21%**	**0.49%**	**3.38%**	**3.37%**	**-0.01%**	**3.72%**	**3.72%**	**3.72%**
Short-term Debt									
Beg Bal	$ 137.3	$ 732.8	$ 595.5	$ 615.4	$ 615.4	$ -	$ 615.4	$ 615.4	$ -
End Bal	140.3	123.9	(16.4)	140.3	123.9	(16.4)	801.8	662.0	(139.8)
Ave Bal	**$ 138.8**	**$ 428.4**	**$ 289.5**	**$ 377.9**	**$ 369.7**	**$ (8.2)**	**$ 560.6**	**$ 633.9**	**$ 73.3**
Interest Exp	**$ 0.2**	**$ 0.4**	**$ 0.2**	**$ 3.6**	**$ 5.4**	**$ 1.8**	**$ 3.4**	**$ 6.0**	**$ 2.6**
Rate	**1.67%**	**1.10%**	**-0.57%**	**1.14%**	**1.73%**	**0.60%**	**1.67%**	**1.67%**	**1.67%**
Total End Bal	**$ 5,757.7**	**$ 5,741.9**	**$ (15.8)**	**$ 5,757.7**	**$ 5,741.9**	**$ (15.8)**	**$ 5,519.4**	**$ 5,380.2**	**$ (139.2)**
Total Average Bal	**$ 5,756.1**	**$ 5,521.3**	**$ (234.8)**	**$ 5,469.9**	**$ 5,462.0**	**$ (7.9)**	**$ 5,327.9**	**$ 5,314.0**	**$ (14.0)**
Total Expense Excl I/C (2)	**$ 17.9**	**$ 18.1**	**$ 0.3**	**$ 145.8**	**$ 149.5**	**$ 3.7**	**$ 181.6**	**$ 186.3**	**$ 4.7**
Rate	**3.60%**	**3.81%**	**0.21%**	**3.16%**	**3.24%**	**0.08%**	**3.60%**	**3.60%**	**3.60%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 140		$ 160
LG&E	500	-		500
KU	598	-	$ 198	400
TOTAL	$ 1,398	$ 140	$ 198	$ 1,060

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	26.8%	-2%	24.6%	-8%
FFO to Debt - KU	21.8%	0%	22.6%	-1%
Debt to EBITDA - LG&E (2)	3.81	0.32	3.72	0.14
Debt to EBITDA - KU (2)	3.95	0.11	3.66	-0.04
Debt to Capitalization - LG&E (3)	50.3%	0%	48.5%	2%
Debt to Capitalization - KU (3)	49.0%	0%	47.6%	1%

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet — October 2015

($ Millions)

	10/31/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 465	$ 432	$ 33	
Accounts Receivable (Trade)	345	391	(46)	Lower customer accounts receivable ($18m) and accrued utility revenue ($27m).
Inventory	285	291	(6)	
Deferred Income Taxes	68	16	52	Due to NOL utilization during the 1st half of 2016 of $41m, an intercompany transfer related to allocations from PPL of $5m and increase in regulatory asset/liability balances associated with billing mechanisms of $4m.
Regulatory Assets Current	30	39	(9)	
Prepayments and other current assets	36	182	(146)	Primarily related to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	1,229	1,351	(121)	
Property, Plant, and Equipment	11,288	11,158	130	
Intangible Assets	132	132	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	689	656	32	
Goodwill	997	997	-	
Other Long-term Assets	101	106	(5)	
Total Assets	**$ 14,437**	**$ 14,401**	**$ 36**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 308	$ 356	$ (48)	Decreases in project engineering accruals, fuel purchases from suppliers and timing of other payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	51	52	(0)	
Derivative Liability	5	71	(66)	Due to settlement of forward starting swaps with PPL.
Accrued Taxes	34	223	(189)	Primarily due to income tax settlement (see Prepayments and other current assets explanation above) and other changes related to bonus depreciation.
Regulatory Liabilities Current	36	12	24	Higher balance primarily due to timing related DSM programs of $8m and over-recovery of fuel costs related to FAC of $13m.
Other Current Liabilities	216	195	21	Primarily related to reclassification of ARO's from noncurrent to current liability of $15m.
Total Current Liabilities	650	909	(259)	
Debt - Affiliated Company	65	49	16	Due to change in tax position related to adoption of bonus depreciation.
Debt [(1)]	5,692	5,693	(1)	
Total Debt	5,758	5,742	16	
Deferred Tax Liabilities	1,489	1,407	82	
Investment Tax Credit	128	128	0	
Accum Provision for Pension & Related Benefits	277	266	11	
Asset Retirement Obligation	489	285	204	Due to revaluation of ARO's to reflect updates in the estimated cash flows for ash and environmental ponds $220m primarily related to the enactment of the Coal Combustion Residuals (CCR) Rule partially offset by a reclassification of ARO from non-current to current liabilities of ($15m).
Regulatory Liabilities Non Current	930	920	10	
Derivative Liability	44	43	1	
Other Liabilities	216	267	(51)	Primarily due to reclassification of retainage related to CR7 project from long-term to short-term ($38m) and a decrease in post-retirement liability due to roll forward of participant census data and VEBA contributions ($24m).
Total Deferred Credits and Other Liabilities	3,573	3,318	256	
Equity	4,455	4,432	23	
Total Liabilities and Equity	**$ 14,437**	**$ 14,401**	**$ 36**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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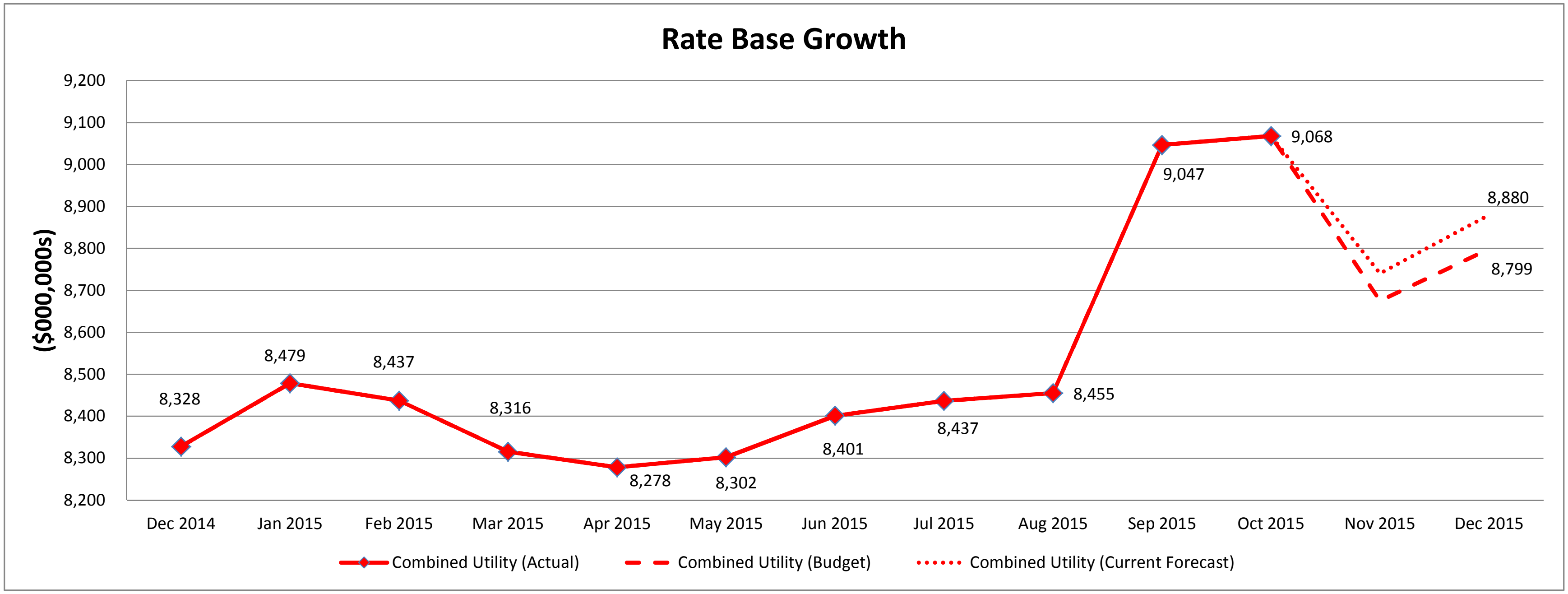

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Performance Report

November 2015

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Kentucky Regulated Dashboard — November 2015

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.44	0.37	1.11	1.04	1.41	1.03
Employee lost-time incidents	0	0	7	6	9	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,425	2,532	31,309	31,525	34,590	34,582
Utility EFOR	7.0%	5.9%	4.0%	5.9%	N/A	5.9%
Utility EAF	63.3%	68.8%	81.9%	83.1%	N/A	83.8%
Steam Fleet Commercial Availability	89.5%	92.0%	93.9%	92.0%	N/A	92.0%
Combined SAIFI	0.06	0.06	0.92	1.11	N/A	1.19
Combined SAIDI (minutes)	4.73	4.75	80.18	99.00	N/A	106.60
GwH Sales						
Residential	659	736	9,638	9,840	10,747	10,842
Commercial	550	598	7,137	7,252	7,848	7,916
Industrial	768	822	9,052	9,164	9,943	10,024
Municipals	134	140	1,713	1,737	1,879	1,890
Other	211	214	2,617	2,487	2,858	2,723
Off-System Sales	5	4	367	268	382	311
Total	2,327	2,514	30,524	30,748	33,658	33,706
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.10%			
Commercial			-0.36%			
Industrial			-1.24%			
Municipal			0.22%			
Other			0.49%			
Total			-0.76%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	7.0%	7.7%	9.4%	8.6%	9.3%	8.9%
Electric Margins	$132	$139	$1,619	$1,617	$1,761	$1,774
Gas Margins	17	15	145	144	167	165
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$2	$2	$19	$44	$26	$47
ECR	27	28	524	541	560	569
Generation	19	10	106	147	134	149
Transmission	7	6	63	55	73	60
Electric Distribution	17	9	157	153	177	162
Gas Distribution	9	6	78	79	89	83
Customer Services	2	1	17	16	21	17
IT and Other	6	3	35	35	40	38
Total	$89	$66	$1,000	$1,070	$1,121	$1,125
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$40	$36	$433	$438	$470	$471
General Counsel & HR	4	3	33	36	38	40
Finance, IT, & Supply Chain	7	6	71	75	79	81
Burdens & Other Charges	11	14	138	161	151	176
Total	$61	$60	$675	$709	$738	$767
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,449	3,566	3,449	3,566	3,512	3,566
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	15	9	N/A	9
NERC Possible Violations[4]	0	0	7	7	N/A	7

Variance Explanations

• Current month lower margins driven by warmer than normal weather resulting in $6 million lower retail electric energy and demand revenues which were partially offset by $2 million higher gas margins.

• YTD lower O&M due to $20 million lower labor and burden costs, including the deferred cost recovery of certain pension and operating expenses as a result of the rate case settlement, $7 million due to timing and other savings for maintenance outages, $3 million in lower uncollectible accounts, $2 million in lower materials and consulting costs and $2 million in lower other expenses.

• Fifteen environmental events have occurred YTD. Thirteen of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred during May at Ghent and a oil spill into the Ohio River at Mill Creek in June due to equipment failure.

Major Developments

• The Company reached a settlement in KU's Virginia rate case. The settlement provides for an annual revenue increase of approximately $6 million (77% of the original request). Upon regulatory approval, rates will be effective February 15, 2016, nearly two months earlier than would have been possible absent a settlement. While a "black box" settlement with no stated return on equity, the settlement provides for an ROE range of 9.5% to 10.5% for annual financial filings and earnings tests.

• The new baghouses for Brown Unit 3 and Ghent Unit 2 were placed into service.

• LG&E and KU have taken another step in the solar market with the intent of offering business and industrial customers individual, renewable generation facilities. The Utilities issued a request for information ("RFI") to contractors with expertise in solar generation design and construction. The RFI will provide facts about the vendors' services, representative costs, and experience so that the Utilities can develop offerings to support their customers' desire for solar energy. LG&E and KU will own and operate the facilities, which will likely range in size from 30 kilowatts to 5 megawatts with each project subject to approval by the KPSC.

• LG&E and KU filed requests with the KPSC to allow the Companies to own and operate electric vehicle charging stations within its service territories. Each utility is requesting approval to install 10 charging stations at different locations for public access. LG&E and KU are also seeking approval to offer business customers an option to host the stations under a five-year commitment. Under the proposed filing, the entire cost of the charging stations, including maintenance, installation and energy usage, will be paid by those who request the stations or the users of the charging service. Currently, there are about 30 public charging stations in Kentucky, 19 of which are located in LKE service territories.

Significant Future Events

• The Trimble County Unit 1 baghouse is scheduled to be in-service by the end of December.

• Construction of the Brown Solar project is underway and the facility is expected to be commercially operational by late spring of 2016.

(1) Full year forecast amount shown represents target.
(2) Excludes goodwill and other purchase accounting adjustments.
(3) Net of cost recovery mechanisms.
(4) The possible violation issues for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget and Forecast (Month) — November 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Variance	Comments	MTD Actual	Q3 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 202	$ 232	$ (30)	See "Electric Margin" explanation below.	$ 202	$ 223	$ (21)	Primarily due to lower energy volumes resulting from unfavorable weather.
Gas Revenues	27	31	(4)		27	29	(2)	
Total Revenues	228	263	(35)		228	252	(24)	
Cost of Sales:								
Fuel Electric Costs	55	73	18	See "Electric Margin" explanation below.	55	68	13	Primarily due to lower energy volumes resulting from unfavorable weather.
Gas Supply Expenses	10	16	7		10	14	4	
Purchased Power	4	7	2		4	4	(0)	
Other Electric Cost	10	13	3		10	12	2	
Total Cost of Sales	79	109	30		79	98	19	
Gross Margin:								
Electric Margin	132	139	(7)	Lower margins driven by warmer than normal weather resulting in $6 million lower retail electric energy and demand revenues.	132	138	(7)	
Gas Margin	17	15	2		17	15	2	
Total Gross Margin	149	154	(5)		149	154	(5)	
Operating Expenses:								
O&M	61	60	(1)		61	66	5	
Depreciation & Amortization	28	30	1		28	29	1	
Taxes, Other than Income	4	5	0		4	5	0	
Total Operating Expenses	94	94	0		94	99	6	
Other income (expense)	(1)	(0)	(1)		(1)	(0)	(1)	
EBIT	54	60	(6)		54	54	(0)	
Interest Expense	17	19	1		17	18	1	
Income from Ongoing Operations before income taxes	36	41	(5)		36	36	0	
Income Tax Expense	14	16	2		14	14	(0)	
Net Income (loss) from ongoing operations	**22**	**25**	**$ (3)**		**$ 22**	**22**	**$ 0**	
Non Operating Income	-	-	-		-	-	-	
Discontinued Operations	(0)	(0)	(0)		(0)	0	(0)	
Net Income (loss)	$ 22	$ 25	$ (3)		$ 22	$ 22	$ 0	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	0	
KY Regulated Net Income	$ 20	$ 23	$ (3)		$ 20	$ 20	$ 0	
Earnings Per Share - Ongoing	$ 0.03	$ 0.03	$ (0.00)		$ 0.03	$ 0.03	$ (0.00)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — November 2015

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,600	$ 2,712	$ (112)	Due to lower volumes driven by unfavorable weather and lower FAC revenues.
Gas Revenues	268	290	(21)	See Gas Supply Expenses explanation below.
Total Revenues	2,868	3,002	(134)	
Cost of Sales:				
Fuel Electric Costs	810	894	84	Primarily due to lower commodity costs related to natural gas.
Gas Supply Expenses	124	146	22	Due to lower net purchases, timing of net exchange gas partially offset by less gas to storage activity.
Purchased Power	50	61	11	Lower purchased power due to mild weather.
Other Electric Cost	121	141	20	Primarily due to lower ECR expense of $12 million and scrubber reactant expense of $7 million.
Total Cost of Sales	1,104	1,242	138	
Gross Margin:				
Electric Margin	1,619	1,617	3	
Gas Margin	145	144	1	
Total Gross Margin	1,764	1,760	4	
Operating Expenses:				
O&M	675	709	35	Due to $20 million lower labor and burden costs, including the deferred cost recovery of certain pension and operating expenses as a result of the rate case settlement, $7 million due to timing and other savings for maintenance outages, $3 million in lower uncollectible accounts, $2 million in lower materials and consulting costs and $2 million in lower other expenses.
Depreciation & Amortization	316	326	10	Lower depreciation primarily due to the timing of retirement and in service dates related to Cane Run units as well as other project completion updates.
Taxes, Other than Income	49	51	2	
Total Operating Expenses	1,040	1,086	46	
Other income (expense)	(6)	(6)	(0)	
EBIT	719	668	50	
Interest Expense	163	168	5	
Income from Ongoing Operations before income taxes	555	500	55	
Income Tax Expense	210	189	(21)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**345**	**311**	**$ 34**	
Non Operating Income	(8)	-	(8)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 337	$ 311	$ 26	
KY Regulated Financing Costs	(31)	$ (31)	(0)	
KY Regulated Net Income	$ 306	$ 280	$ 26	
Earnings Per Share - Ongoing	$ 0.47	$ 0.42	$ 0.05	

Note: Schedules may not sum due to rounding.

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Electric Gross Margin — November 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ (7)						$ (23)
Energy Volumes (a)	2,322,109	2,509,497	(187,388)		$ (6.4)		30,156,987	30,479,579	(322,592)		$ (12.6)	
Energy Prices (a)					$ (3.8)						$ (21.8)	
Customer Charges (Avg. Customers)	948,321	958,412	(10,091)		$ (0.5)		945,368	956,344	(10,975)		(2.4)	
Demand Charges (b)	$ 43	$ 39			$ 4.0		478	464			14.0	
ECR:						$ 0						$ 18
Average Rate Base	$ 2,045	$ 2,059	$ (14)	10.30%	$ (0.1)		$ 1,896	$ 1,883	$ 13	10.17%	$ 1.1	
Cost of Capital	10.18%	10.30%	-0.12%	$ 2,045	$ (0.2)		10.29%	10.17%	0.12%	$ 1,896	1.9	
Jurisdictional Factor	92.19%	89.92%	2.27%	$ 2,045	$ 0.4		90.73%	90.47%	0.26%	$ 1,896	0.5	
Other					$ (0.1)						14.9	
DSM:						$ (1)						$ (4)
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.7	$ 0.6			$ 0.1	
Lost Sales	0.4	1.1			$ (0.6)		9.8	11.6			$ (1.8)	
Incentive	0.1	0.1			$ (0.0)		0.9	0.9			$ (0.1)	
Balancing Adjustment	-	-			$ -		(1.9)	-			$ (1.9)	
Net Fuel Recovery	$ (1.2)	$ (0.3)				$ (1)	$ (4.7)	$ (4.4)				$ (0)
Purchase Power Demand	(2.8)	(3.0)				$ 0	(29.0)	(30.2)				$ 1
Transmission	0.6	0.3				$ 0	9.6	6.6				$ 3
Other	(0.4)	(0.7)				$ 0	(10.6)	(14.9)				$ 4
Retail Margin Variance						$ (7)						$ (0)
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ (7)						$ 3

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 35	658,584	$ 53.45	$ 39	736,178	$ 53.32	($4.1)	($4.1)	$0.1
Commercial	16	549,598	29.51	20	597,900	32.99	($3.5)	($1.6)	($1.9)
Industrial	6	768,375	8.00	8	821,623	9.80	($1.9)	($0.5)	($1.4)
Municipals	1	134,234	4.99	1	139,749	5.22	($0.1)	($0.0)	($0.0)
Other	5	211,318	22.08	5	214,047	25.01	($0.7)	($0.1)	($0.6)
Native Load Total	**$ 63**	**2,322,109**	**$ 27.09**	**$ 73**	**2,509,497**	**$ 29.14**	**($10.2)**	**($6.4)**	**($3.8)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 488	9,637,161	$ 50.61	$ 499	9,840,629	$ 50.72	($11.4)	($10.5)	($0.9)
Commercial	220	7,137,197	30.85	233	7,251,573	32.15	($12.9)	($3.7)	($9.3)
Industrial	77	9,052,469	8.55	86	9,163,222	9.38	($8.6)	($1.0)	($7.5)
Municipals	8	1,713,022	4.91	9	1,735,655	5.22	($0.6)	($0.1)	($0.5)
Other	59	2,617,137	22.61	60	2,488,500	24.14	($0.9)	$2.7	($3.6)
Native Load Total	**$ 853**	**30,156,987**	**$ 28.28**	**$ 887**	**30,479,579**	**$ 29.11**	**($34.4)**	**($12.6)**	**($21.8)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	14	12	1	155	155	(1)
Industrial	19	17	2	200	190	10
Municipals	4	4	(0)	56	57	(0)
Other	6	5	1	68	62	5
Native Load Total	**43**	**39**	**4**	**478**	**464**	**14**

Weather - Avg. Hourly Temperature [1]	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	52	(4)	-7%	43	2	4%
(°F) Lexington Heating Season	51	(4)	-9%	42	2	4%
(°F) Louisville Cooling Season	-	-	-	72	1	1%
(°F) Lexington Cooling Season	-	-	-	69	1	1%

[1] Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — November 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 56**	**$ 56**		**$ (0)**
Gas Supply Costs								
Gas Supply Costs	(9)	(15)	$ 7		(115)	(139)	24	
GSC Revenue	9	15	$ (7)		115	139	(24)	
Net Gas Supply Costs				**0**				**$ 0**
Retail Gas (a)	**8**	**9**		**(1)**	**75**	**75**		**$ (0)**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**$ -**
DSM	**0**	**0**		**0**	**0**	**0**		**$ (0)**
GLT	**1**	**1**		**0**	**11**	**10**		**$ 0**
WNA	**3**	**-**		**3**	**2**	**-**		**$ 2**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**$ 0**
Gas Margin Variance				**$ 2**				**$ 1**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 5	1,640,754	$ 2.87	$ 5	1,841,795	$ 2.79	($0.4)	($0.6)	$0.1
Commercial	2	737,585	2.19	2	831,741	2.21	($0.2)	($0.2)	($0.0)
Industrial	0	123,400	2.39	0	142,350	1.91	$0.0	($0.0)	$0.1
Public Authority	0	98,660	2.21	0	136,810	2.19	($0.1)	($0.1)	$0.0
Transportation	1	1,272,252	0.50	1	1,360,348	0.47	($0.0)	($0.0)	$0.0
Interdepartmental	0	25,719	12.28	0	41,298	11.26	($0.1)	($0.2)	$0.0
Ultimate Consumer	$ 8	3,898,370	$ 2.00	$ 9	4,354,342	$ 1.99	($0.9)	($1.1)	$0.2

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 45	16,625,097	$ 2.69	$ 45	16,657,752	$ 2.68	$0	$ (0)	$ 0
Commercial	16	7,860,752	2.06	16	7,540,435	2.12	$0	$ 1	$ (1)
Industrial	2	1,284,574	1.90	2	1,294,218	1.84	$0	$ (0)	$ 0
Public Authority	2	1,134,280	2.00	3	1,248,152	2.09	($0)	$ (0)	$ (0)
Transportation	6	12,919,228	0.46	5	10,687,122	0.45	$1	$1	$0
Interdepartmental	4	361,571	9.99	5	1,733,918	2.88	($1)	($4)	$3
Ultimate Consumer	$ 75	40,185,502	$ 1.87	$ 75	39,161,598	$ 1.93	($0)	($3)	$2

($ Millions)

	MTD Actual	MTD Budget	MTD Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 21	$ 18	$ (3)	$ (1)	$ (1)	$ (1)	$ (0)		$ (0)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	0	0		0	0		(0)
Energy Supply and Analysis	1	1	(0)	(0)		0	0		0
Generation Services	1	1	(0)	(0)		(0)	0		0
Electric Distribution	4	5	0	0		0	(0)	0	(0)
Gas Distribution	3	3	(0)	(0)		(0)	(0)	0	(0)
Safety and Security	0	0	(0)	(0)		(0)	(0)	0	0
Customer Services	7	6	(0)	(0)		0	0	(0)	(0)
Chief Operations Officer	**40**	**36**	**(4)**	**(2)**	**(1)**	**(1)**	**(0)**	**(0)**	**(1)**
General Counsel	3	3	(1)	(0)		0	0		(1)
Human Resources	1	1	0	(0)		0	0		0
General Counsel & HR	**4**	**3**	**(1)**	**(0)**		**0**	**0**		**(1)**
Information Technology	5	4	(1)	(0)		(0)	(0)		0
Supply Chain	0	0	(0)	(0)		0	0		0
Finance	2	1	(0)	(0)		0	(0)		(0)
Chief Financial Officer	**7**	**6**	**(1)**	**(0)**		**(0)**	**(0)**		**0**
Corporate	**11**	**14**	**4**	**3**		**0**	**(0)**	**(0)**	**1**
O&M Total MTD	**$ 61**	**$ 60**	**$ (1)**	**$ 1**	**$ (1)**	**$ (1)**	**$ (0)**	**$ (0)**	**$ (0)**

	YTD Actual	YTD Budget	YTD Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 209	$ 211	$ 2	$ (1)	8	$ (2)	$ 0		$ (3)
Project Engineering	0	1	0	0		(0)	(0)		0
Transmission	28	27	(1)	(0)		(2)	1		(0)
Energy Supply and Analysis	8	8	0	(0)		0	0		0
Generation Services	12	13	1	(0)		1	(0)		0
Electric Distribution	66	64	(1)	(0)		(1)	0	0	(0)
Gas Distribution	31	31	(0)	0		1	(0)	(0)	(1)
Safety and Security	4	4	0	(0)		(0)	0	0	0
Customer Services	76	80	4	(0)		2	1	3	(1)
Chief Operations Officer	**$ 433**	**$ 438**	**5**	**(2)**	**8**	**(1)**	**2**	**3**	**(4)**
General Counsel	27	29	3	0		2	0		0
Human Resources	6	7	1	0		0	(0)		0
General Counsel & HR	**$ 33**	**$ 36**	**4**	**1**		**3**	**0**		**0**
Information Technology	50	53	3	3		(1)	(0)		2
Supply Chain	3	3	(0)	(0)		0	0		0
Finance	18	18	1	(0)		0	0		1
Chief Financial Officer	**$ 71**	**$ 75**	**3**	**2**		**(1)**	**(0)**		**2**
Corporate	**$ 138**	**$ 161**	**23**	**19**		**(0)**	**(0)**	**0**	**4**
O&M Total YTD	**$ 675**	**$ 709**	**$ 35**	**$ 20**	**$ 8**	**$ 1**	**$ 1**	**$ 3**	**$ 2**

	Full Year Forecast	Full Year Budget	Full Year Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 225	$ 225	$ (0)	$ (2)	$ 5	$ (8)	$ 1		$ 4
Project Engineering	0	1	0	0		(0)	(0)		0
Transmission	30	29	(1)	(0)		(1)	1		(0)
Energy Supply and Analysis	9	9	0	(0)		0	0		0
Generation Services	13	14	0	(0)		1	0		(1)
Electric Distribution	71	70	(2)	(1)		(1)	0	0	0
Gas Distribution	34	33	(1)	(0)		0	0	(0)	(1)
Safety and Security	4	4	0	(0)		(0)	(0)	0	0
Customer Services	83	87	3	(0)		2	1	2	(1)
Chief Operations Officer	**$ 470**	**$ 471**	**0**	**(4)**	**5**	**(7)**	**3**	**2**	**2**
General Counsel	31	33	1	(0)		2	(0)		(1)
Human Resources	7	7	1	0		0	0		0
General Counsel & HR	**$ 38**	**$ 40**	**2**	**0**		**2**	**(0)**		**(0)**
Information Technology	55	58	2	2		(1)	(0)		1
Supply Chain	4	4	(0)	(0)		0	0		0
Finance	20	20	0	(0)		(0)	0		0
Chief Financial Officer	**$ 79**	**$ 81**	**2**	**2**		**(1)**	**(0)**		**2**
Corporate	**$ 151**	**$ 176**	**24**	**21**		**0**	**(0)**	**0**	**3**
O&M Total YTD	**$ 738**	**$ 767**	**$ 29**	**$ 19**	**$ 5**	**$ (6)**	**$ 2**	**$ 3**	**$ 7**

Note: Schedules may not sum due to rounding.

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Financing Activities — November 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 923.9	$ 0.0	$ 923.9	$ 923.9	$ -	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	0.0	923.9	923.9	0.0	923.9	923.9	(0.1)
Ave Bal	$ 923.9	$ 923.9	$ 0.0	$ 923.9	$ 923.9	$ 0.0	$ 923.9	$ 923.9	$ (0.0)
Interest Exp	$ 0.9	$ 1.1	$ 0.3	$ 9.4	$ 12.6	$ 3.2	$ 10.4	$ 13.8	$ 3.4
Rate	1.11%	1.49%	0.38%	1.10%	1.47%	0.37%	1.12%	1.49%	0.37%
FMB/Sr Nts [(1)]									
Beg Bal	$ 4,693.5	$ 4,694.2	$ 0.7	$ 3,642.7	$ 3,642.7	$ -	$ 3,642.7	$ 3,642.7	$ -
End Bal	4,193.6	4,194.3	0.6	4,193.6	4,194.3	0.6	4,193.7	4,194.4	0.7
Ave Bal	$ 4,443.6	$ 4,444.2	$ 0.6	$ 3,918.2	$ 3,918.5	$ 0.3	$ 3,910.1	$ 3,822.8	$ (87.3)
Interest Exp	$ 15.2	$ 15.9	$ 0.7	$ 134.1	$ 134.5	$ 0.4	$ 147.9	$ 148.3	$ 0.4
Rate	4.12%	4.30%	0.19%	3.69%	3.70%	0.01%	3.78%	3.88%	0.10%
Short-term Debt									
Beg Bal	$ 140.3	$ 123.9	$ (16.4)	$ 615.4	$ 615.4	$ -	$ 615.4	$ 615.4	$ -
End Bal	282.5	274.5	(8.0)	282.5	274.5	(8.0)	401.8	262.0	(139.8)
Ave Bal	$ 211.4	$ 199.2	$ (12.2)	$ 449.0	$ 445.0	$ (4.0)	$ 494.0	$ 567.3	$ 73.3
Interest Exp	$ 0.2	$ 0.3	$ 0.1	$ 3.9	$ 5.7	$ 1.8	$ 3.4	$ 6.0	$ 2.6
Rate	1.33%	1.77%	0.44%	0.93%	1.38%	0.46%	0.69%	1.06%	0.37%
Total End Bal	$ 5,400.0	$ 5,392.6	$ (7.4)	$ 5,400.0	$ 5,392.6	$ (7.4)	$ 5,519.4	$ 5,380.2	$ (139.2)
Total Average Bal	$ 5,578.9	$ 5,567.3	$ (11.6)	$ 5,291.0	$ 5,287.3	$ (3.7)	$ 5,327.9	$ 5,314.0	$ (14.0)
Total Expense Excl I/C [(2)]	$ 17.5	$ 18.6	$ 1.2	$ 163.3	$ 168.2	$ 4.9	$ 181.6	$ 186.3	$ 4.7
Rate	3.75%	4.02%	0.27%	3.33%	3.43%	0.10%	3.41%	3.51%	0.09%

(1) Include FMBs maturing in November 2015 $900m.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 154		$ 146
LG&E	500	128		372
KU	598	-	$ 198	400
TOTAL	$ 1,398	$ 282	$ 198	$ 918

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	29.0%	-3%	24.6%	-8%
FFO to Debt - KU	27.1%	2%	22.6%	-1%
Debt to EBITDA - LG&E [(2)]	3.56	-0.09	3.72	0.14
Debt to EBITDA - KU [(2)]	3.58	-0.18	3.66	-0.04
Debt to Capitalization - LG&E [(3)]	49.0%	1%	48.5%	2%
Debt to Capitalization - KU [(3)]	46.8%	-1%	47.6%	1%

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet — November 2015

($ Millions)

	11/30/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 17	$ 17	$ 0	
Accounts Receivable (Trade)	350	399	(49)	Lower customer accounts receivable ($32m) and accrued utility revenue ($17m).
Inventory	300	303	(3)	
Deferred Income Taxes	68	16	52	Due to NOL utilization during the 1st half of 2016 of $41m, an intercompany transfer related to allocations from PPL of $5m and increase in regulatory asset/liability balances associated with billing mechanisms of $4m.
Regulatory Assets Current	34	42	(8)	
Prepayments and other current assets	33	184	(151)	Primarily related to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below.
Total Current Assets	801	960	(159)	
Property, Plant, and Equipment	11,336	11,187	149	
Intangible Assets	127	128	(0)	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	707	655	51	
Goodwill	997	997	-	
Other Long-term Assets	101	106	(5)	
Total Assets	**$ 14,070**	**$ 14,035**	**$ 36**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 305	$ 354	$ (49)	Decreases in project engineering accruals, fuel purchases from suppliers and timing of other payables.
Dividends Payable to Affiliated Companies	62	-	62	Dividend payable $62m issued to PPL based on Q3 2015 net income.
Customer Deposits	51	52	(0)	
Derivative Liability	5	71	(66)	Due to settlement of forward starting swaps with PPL.
Accrued Taxes	53	232	(179)	Primarily due to income tax settlement (see Prepayments and other current assets explanation above) and other changes related to bonus depreciation.
Regulatory Liabilities Current	36	12	24	Higher balance primarily due to timing related DSM programs of $6m and over-recovery of fuel costs related to FAC of $15m.
Other Current Liabilities	162	149	13	
Total Current Liabilities	674	870	(196)	
Debt - Affiliated Company	479	461	18	
Debt [1]	4,920	4,932	(11)	
Total Debt	5,400	5,393	7	
Deferred Tax Liabilities	1,489	1,407	82	
Investment Tax Credit	128	128	0	
Accum Provision for Pension & Related Benefits	279	268	12	
Asset Retirement Obligation	499	287	213	Due to revaluation of ARO's to reflect updates in the estimated cash flows for ash and environmental ponds primarily related to the enactment of the Coal Combustion Residuals (CCR) Rule.
Regulatory Liabilities Non Current	927	914	13	
Derivative Liability	44	43	0	
Other Liabilities	214	268	(54)	Primarily due to reclassification of retainage related to CR7 project from long-term to short-term and a decrease in post-retirement liability due to roll forward of participant census data and VEBA contributions.
Total Deferred Credits and Other Liabilities	3,580	3,314	266	
Equity	4,416	4,458	(42)	
Total Liabilities and Equity	**$ 14,070**	**$ 14,035**	**$ 36**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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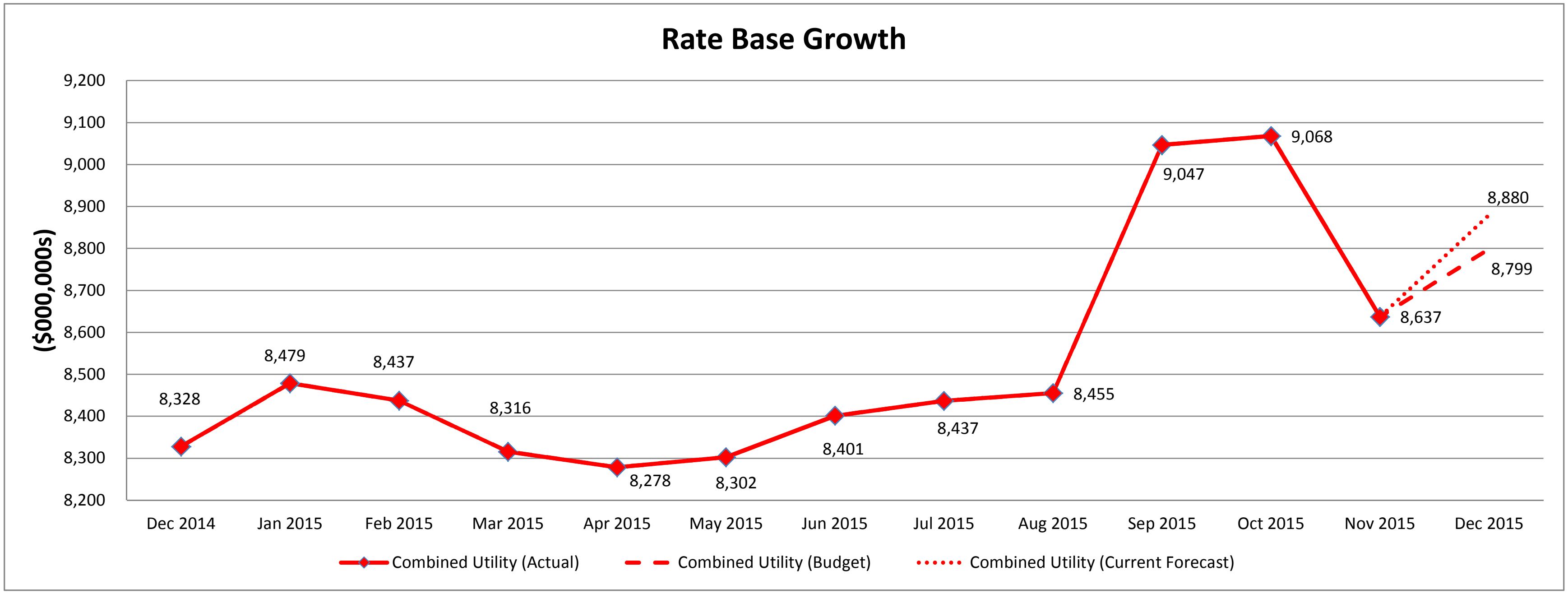

Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,328
8,479
8,437
8,316
8,278
8,302
8,401
8,437
8,455
9,047
9,068
8,637
8,880
8,799
Dec 2014
Jan 2015
Feb 2015
Mar 2015
Apr 2015
May 2015
Jun 2015
Jul 2015
Aug 2015
Sep 2015
Oct 2015
Nov 2015
Dec 2015
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

Performance Report

December 2015

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Kentucky Regulated Dashboard — December 2015

	Current Month		YTD	
Safety	Actual	PY	Actual	PY
TCIR - Employees	2.63	1.25	1.22	1.03
Employee lost-time incidents	0	0	8	6
Reliability	Actual	Budget	Actual	Budget
Generation Volumes	2,796	3,056	34,105	34,582
Utility EFOR	3.4%	5.9%	3.9%	5.9%
Utility EAF	91.2%	91.3%	82.3%	83.8%
Steam Fleet Commercial Availability	88.5%	92.0%	93.4%	92.0%
Combined SAIFI	0.08	0.08	1.00	1.19
Combined SAIDI (minutes)	7.07	7.60	87.25	106.60
GwH Sales				
Residential	812	1,002	10,450	10,842
Commercial	605	664	7,742	7,916
Industrial	733	860	9,785	10,024
Municipals	142	154	1,855	1,891
Other	219	234	2,836	2,721
Off-System Sales	18	43	385	311
Total	2,529	2,957	33,053	33,705
Weather-Normalized Sales Growth			TTM	
Residential			-1.78%	
Commercial			-0.24%	
Industrial			-2.19%	
Municipal			0.19%	
Other			-0.07%	
Total			-1.29%	

	Current Month		YTD	
Financial Metrics	Actual	Budget	Actual	Budget
Utility ROE[1]	9.7%	12.3%	9.4%	8.9%
Electric Margins	$142	$158	$1,761	$1,774
Gas Margins	20	21	164	165
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget
New Generation	$8	$2	$27	$47
ECR	21	28	545	569
Generation	24	2	131	149
Transmission	10	5	73	60
Electric Distribution	20	9	178	162
Gas Distribution	10	4	88	83
Customer Services	3	2	20	17
IT and Other	3	3	38	38
Total	$99	$55	$1,099	$1,125
O&M ($ millions)[2]	Actual	Budget	Actual	Budget
Operations	$36	$33	$469	$471
General Counsel & HR	5	4	38	40
Finance, IT, & Supply Chain	8	7	79	81
Burdens & Other Charges	13	15	151	176
Total	$62	$58	$736	$767
Head Count	Actual	Budget	Actual	Budget
Full-time Employees	3,465	3,566	3,465	3,566
Other Metrics	Actual	PY	Actual	PY
Environmental Events**	1	0	16	9
NERC Possible Violations[3]	1	0	8	7

Variance Explanations

• Current month lower margins driven by warmer than normal weather resulting in $17 million lower retail electric energy revenues.

• YTD lower margins primarily due to $39 million lower net retail electric base revenues and $4 million lower DSM net revenues offset by higher ECR margins of $17 million resulting from earlier timing of spend and other adjustments, $5 million from lower cost of production margin expenses, $3 million from the sale of excess generation and $3 million from higher transmission revenues.

• The current month capital expenditure variance reflects a catch-up of spending on certain projects.

• YTD lower O&M due to $19 million lower labor and burden costs, including the deferred cost recovery of certain pension and operating expenses as a result of the rate case settlement, $6 million favorable maintenance and outage expenses, $3 million in lower uncollectible accounts and $2 million in lower materials and consulting costs.

• Sixteen environmental events occurred during 2015. Thirteen of the events were a result of SO2, NOx, CO and mercury exceedances at Mill Creek and Trimble County. These events were short timeframe limits which were exceeded and were all due to equipment malfunctions. In addition, there was a sulfuric acid spill that occurred at Ghent and two oil spills into the Ohio River; one at Mill Creek due to equipment failure and the second at Ohio Falls during maintenance work.

Major Developments

• The Company received an Order from the KPSC reaffirming the CPCN approvals to build a new on-site special waste landfill at the Trimble County Station and to continue with the special waste landfill project as planned at the Ghent Generating Station. The Order resolves a complaint filed by Sterling Ventures LLC requesting that the KPSC revoke previous CPCNs for our on-site landfills and instead use Sterling Ventures' underground limestone mine for beneficial use of our coal combustion residuals ("CCR"). The KPSC agreed with LKE's position that the Company's location and site designs for the projects previously approved by the KPSC continue to represent the least-cost feasible option for our customers, and that the Sterling site would not meet the new beneficial use aspects of the EPA's CCR regulations. While the state is still working on final environmental permits needed to construct the landfill itself, the Company has the necessary permits to begin construction of the CCR treatment facility. Once the EPC contract negotiations are completed and signed by the selected contractor in early 2016, the project will begin.

• The new baghouse for Trimble County 1 ("TC1") was placed into service in December. With TC1 in service, all baghouse projects to date (9) in the Mercury and Air Toxics Standards ("MATS") compliance program have been placed in service on or ahead of schedule, with the final project scheduled to be placed in service Q2 2016.

• Both Louisville and Lexington recorded its warmest December in more than a century. Temperatures averaged 49 degrees for the month, surpassed only by December 1889, when the average temperatures slightly topped 50 degrees.

• Through the Company's 2015 annual charitable-giving campaign, Power of One, LKE donated nearly $1.8 million for Metro United Way, Fund for the Arts and Crusade for Children. This marks the ninth year in a row in which employees have raised more than $1 million, and it represents the highest amount ever pledged in the history of the campaign.

Significant Future Events

• The Mill Creek 3 baghouse construction is progressing toward an April 2016 tie-in outage. The unit will be restarted during June 2016 in compliance with the MATS rule.

• Construction of the Brown Solar project is underway and the facility is expected to be commercially operational by late spring of 2016.

(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues for YTD Actual is believed to be minimal risk.

**Current year month and YTD amounts shown for environmental events were revised to reflect updated information.

Income Statement: Actual vs. Budget (Month) — December 2015

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 217	$ 264	$ (47)	See "Electric Margin" explanation below.
Gas Revenues	34	51	(17)	See Gas Supply Expenses explanation below.
Total Revenues	251	315	(64)	
Cost of Sales:				
Fuel Electric Costs	58	86	28	See "Electric Margin" explanation below.
Gas Supply Expenses	15	29	15	Due to lower net purchases and less gas from storage activity.
Purchased Power	5	5	0	
Other Electric Cost	12	15	3	
Total Cost of Sales	90	136	46	
Gross Margin:				
Electric Margin	142	158	(16)	Lower margins driven by warmer than normal weather resulting in $17 million lower retail electric energy revenues.
Gas Margin	20	21	(2)	
Total Gross Margin	161	179	(18)	
Operating Expenses:				
O&M	62	58	(4)	
Depreciation & Amortization	29	30	2	
Taxes, Other than Income	4	5	0	
Total Operating Expenses	94	93	(2)	
Other income (expense)	(2)	(0)	(1)	
EBIT	66	86	(20)	
Interest Expense	17	18	1	
Income from Ongoing Operations before income taxes	48	68	(20)	
Income Tax Expense	17	25	9	Due to lower pre-tax income.
Net Income (loss) from ongoing operations	**31**	**42**	**$ (11)**	
Non Operating Income	(4)	-	(4)	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 27	$ 42	$ (15)	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 25	$ 40	$ (15)	
Earnings Per Share - Ongoing	$ 0.04	$ 0.06	$ (0.02)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) — December 2015

($ Millions)

	YTD Actual	YTD Budget	YTD Variance	Comments
Revenues:				
Electric Revenues	$ 2,817	$ 2,976	$ (160)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	303	340	(38)	See Gas Supply Expenses explanation below.
Total Revenues	3,119	3,317	(197)	
Cost of Sales:				
Fuel Electric Costs	868	980	112	Primarily due to lower commodity costs related to lower fuel prices and lower volume usage due to decreased generation.
Gas Supply Expenses	138	175	37	Due to lower net purchases partially offset by less gas to storage activity.
Purchased Power	55	66	11	Lower purchased power due to mild weather.
Other Electric Cost	132	156	24	Primarily due to lower ECR expense of $14 million and scrubber reactant expense of $8 million.
Total Cost of Sales	1,194	1,377	184	
Gross Margin:				
Electric Margin	1,761	1,774	(13)	Primarily due to $39 million lower retail electric base service, energy and demand revenues and $4 million lower DSM revenues offset by higher ECR margins of $17 million resulting from earlier timing of spend and other adjustments, $5 million from lower cost of production margin expenses, $3 million from the sale of excess generation and $3 million from higher transmission revenues.
Gas Margin	164	165	(1)	
Total Gross Margin	1,926	1,939	(14)	
Operating Expenses:				
O&M	736	767	31	Lower O&M due to $19 million lower labor and burden costs, including the deferred cost recovery of certain pension and operating expenses as a result of the rate case settlement, $6 million favorable maintenance and outage expenses, $3 million in lower uncollectible accounts and $2 million in lower materials and consulting costs.
Depreciation & Amortization	344	356	12	Lower depreciation primarily due to the timing of retirement and in service dates related to Cane Run units as well as other project completion updates.
Taxes, Other than Income	53	55	2	
Total Operating Expenses	1,134	1,179	45	
Other income (expense)	(7)	(6)	(1)	
EBIT	784	754	30	
Interest Expense	181	186	6	Interest savings due to a combination of changes in short term debt balances and more favorable interest rates during the year.
Income from Ongoing Operations before income taxes	603	568	35	
Income Tax Expense	227	215	(12)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**376**	**353**	**$ 23**	
Non Operating Income	(12)	-	(12)	Due to valuation allowance recorded for tax credits that will not be utilized as a result of the bonus depreciation extension.
Discontinued Operations	0	(0)	1	
Net Income (loss)	$ 364	$ 353	$ 11	
KY Regulated Financing Costs	(33)	$ (33)	(0)	
KY Regulated Net Income	$ 331	$ 320	$ 11	
Earnings Per Share - Ongoing	$ 0.51	$ 0.47	$ 0.03	

Note: Schedules may not sum due to rounding.

Electric Gross Margin — December 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ (16)						$ (39)
Energy Volumes (a)	2,511,818	2,914,664	(402,845)		$ (13.8)		32,668,805	33,394,243	(725,438)		$ (25.8)	
Energy Prices (a)					$ (3.5)						$ (25.9)	
Customer Charges (Avg. Customers)	949,206	958,841	(9,635)		$ (0.4)		945,688	956,552	(10,864)		(2.8)	
Demand Charges (b)	$ 42	$ 40			$ 1.5		520	505			15.5	
ECR:						$ (1)						$ 17
Average Rate Base	$ 1,962	$ 2,059	$ (97)	10.37%	$ (0.8)		$ 1,901	$ 1,898	$ 3	10.19%	$ 0.3	
Cost of Capital	10.07%	10.37%	-0.30%	$ 1,962	$ (0.4)		10.27%	10.19%	0.08%	$ 1,901	1.4	
Jurisdictional Factor	91.72%	89.79%	1.93%	$ 1,962	$ 0.3		90.81%	90.40%	0.41%	$ 1,901	0.8	
Other					$ (0.4)						14.5	
DSM:						$ (0)						$ (4)
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ 0.0		$ 0.7	$ 0.6			$ 0.1	
Lost Sales	1.0	1.1			$ (0.1)		10.8	12.7			$ (1.9)	
Incentive	0.1	0.1			$ 0.0		1.0	1.0			$ (0.1)	
Balancing Adjustment	(0.0)	-			$ (0.0)		(1.9)	-			$ (1.9)	
Net Fuel Recovery	$ 1.5	$ (0.4)				$ 2	$ (3.1)	$ (4.8)				$ 2
Purchase Power Demand	(3.9)	(3.0)				$ (1)	(32.8)	(33.2)				$ 0
Transmission	0.7	0.6				$ 0	10.3	7.2				$ 3
Other	(0.8)	(1.4)				$ 1	(11.4)	(16.2)				$ 5
Retail Margin Variance						$ (16)						$ (16)
Off-System Margin Variance						$ 0						$ 3
Electric Margin Variance						$ (16)						$ (13)

(a) Non-Fuel Energy Analysis (net of base ECR revenue): MTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 43	812,114	$ 53.26	$ 53	1,001,812	$ 53.02	($9.9)	($10.1)	$0.2
Commercial	18	605,259	30.05	22	664,292	33.79	($4.3)	($2.1)	($2.2)
Industrial	6	733,113	8.06	9	860,365	9.88	($2.6)	($1.3)	($1.3)
Municipals	1	142,359	6.74	1	154,121	5.22	$0.2	($0.1)	$0.2
Other	5	218,974	23.03	6	234,074	24.65	($0.7)	($0.3)	($0.4)
Native Load Total	**$ 73**	**2,511,818**	**$ 29.21**	**$ 91**	**2,914,664**	**$ 31.10**	**($17.3)**	**($13.8)**	**($3.5)**

(a) Non-Fuel Energy Analysis (net of base ECR revenue): YTD

	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 531	10,449,275	$ 50.82	$ 552	10,842,441	$ 50.94	($21.2)	($20.1)	($1.1)
Commercial	238	7,742,456	30.79	256	7,915,865	32.28	($17.2)	($5.6)	($11.6)
Industrial	83	9,785,582	8.51	94	10,023,587	9.42	($11.2)	($2.2)	($8.9)
Municipals	9	1,855,381	5.05	10	1,889,776	5.22	($0.5)	($0.2)	($0.3)
Other	64	2,836,111	22.65	66	2,722,574	24.18	($1.6)	$2.4	($4.0)
Native Load Total	**$ 926**	**32,668,805**	**$ 28.35**	**$ 978**	**33,394,243**	**$ 29.29**	**($51.7)**	**($25.8)**	**($25.9)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	13	13	0	168	168	(0)
Industrial	19	17	1	219	208	11
Municipals	4	5	(1)	60	61	(1)
Other	6	5	0	74	68	6
Native Load Total	**42**	**40**	**1**	**520**	**505**	**16**

Weather - Avg. Hourly Temperature (1)	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
(°F) Louisville Heating Season	49	(10)	-20%	44	(0)	-1%
(°F) Lexington Heating Season	48	(11)	-23%	43	(0)	-1%
(°F) Louisville Cooling Season	-	-	-	72	1	1%
(°F) Lexington Cooling Season	-	-	-	69	1	1%

(1) Heating Season includes January through April and November and December. Cooling Season includes May through October.

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Gas Gross Margin — December 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	$ 5	$ 5		(0)	$ 61	$ 62		$ (1)
Gas Supply Costs								
Gas Supply Costs	(14)	(29)	$ 15		(129)	(168)	39	
GSC Revenue	14	29	$ (14)		130	168	(38)	
Net Gas Supply Costs				0				$ 1
Retail Gas (a)	10	15		(5)	85	90		$ (5)
Wholesale Gas (a)	-	-		-	-	-		$ -
DSM	0	0		(0)	0	0		$ (0)
GLT	1	1		0	12	11		$ 1
WNA	3	-		3	4	-		$ 4
Other Margin	0	0		(0)	2	2		$ (0)
Gas Margin Variance				$ (2)				$ (1)

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 6	2,215,036	$ 2.87	$ 10	3,427,080	$ 2.79	($3.2)	($3.4)	$0.2
Commercial	2	937,452	2.15	3	1,498,271	2.22	($1.3)	($1.2)	($0.1)
Industrial	0	97,689	2.19	0	183,304	1.96	($0.1)	($0.2)	$0.0
Public Authority	0	137,990	2.12	1	243,687	2.20	($0.2)	($0.2)	($0.0)
Transportation	1	1,190,907	0.56	1	1,534,226	0.47	($0.1)	($0.2)	$0.1
Interdepartmental	0	50,331	6.17	0	36,918	12.56	($0.2)	$0.2	($0.3)
Ultimate Consumer	$ 10	4,629,405	$ 2.13	$ 15	6,923,488	$ 2.16	($5.1)	($5.0)	($0.1)

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 51	18,840,133	$ 2.71	$ 54	20,084,833	$ 2.70	($3)	$ (3)	$ 0
Commercial	18	8,798,204	2.07	19	9,038,706	2.14	($1)	$ (1)	$ (1)
Industrial	3	1,382,263	1.92	3	1,477,522	1.85	($0)	$ (0)	$ 0
Public Authority	3	1,272,270	2.01	3	1,491,840	2.11	($1)	$ (0)	$ (0)
Transportation	7	14,110,135	0.47	6	12,221,349	0.45	$1	$1	$0
Interdepartmental	4	411,902	9.52	5	1,770,836	3.08	($2)	($4)	$3
Ultimate Consumer	$ 85	44,814,907	$ 1.90	$ 90	46,085,086	$ 1.96	($5)	($8)	$2

O&M									December 2015

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 14	$ 14	$ (1)	$ (0)	$ (1)	$ 0	$ 1		$ (0)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	0	(0)		(0)	0		(0)
Energy Supply and Analysis	1	1	(0)	(0)		0	0		0
Generation Services	1	1	0	(0)		0	(0)		0
Electric Distribution	6	5	(1)	0		(1)	(0)	(0)	0
Gas Distribution	3	3	(1)	(0)		(0)	(0)	(0)	0
Safety and Security	0	0	(0)	(0)		(0)	0	0	0
Customer Services	8	7	(1)	(1)		(0)	0	0	(0)
Chief Operations Officer	**36**	**33**	**(3)**	**(1)**	**(1)**	**(1)**	**1**	**0**	**(0)**
General Counsel	4	3	(1)	(0)		(0)	(0)		(1)
Human Resources	1	1	(0)	(0)		(0)	(0)		(0)
General Counsel & HR	**5**	**4**	**(1)**	**(0)**		**(0)**	**(0)**		**(1)**
Information Technology	6	5	(1)	(0)		(0)	(0)		(0)
Supply Chain	0	0	(0)	(0)		(0)	0		(0)
Finance	2	2	(1)	(0)		(0)	(0)		(0)
Chief Financial Officer	**8**	**7**	**(1)**	**(1)**		**(0)**	**(0)**		**(0)**
Corporate	**13**	**15**	**2**	**2**		**0**	**(0)**	**0**	**(1)**
O&M Total MTD	**$ 62**	**$ 58**	**$ (4)**	**$ (0)**	**$ (1)**	**$ (1)**	**$ 1**	**$ 0**	**$ (2)**

	YTD								
	Actual	Budget	Total Variance	Labor & Burdens	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 223	$ 225	$ 1	$ (1)	6	$ (2)	$ 1		$ (4)
Project Engineering	0	1	0	0		(0)	(0)		0
Transmission	30	29	(1)	(1)		(2)	1		(0)
Energy Supply and Analysis	9	9	(0)	(0)		0	0		0
Generation Services	13	14	1	(0)		1	(0)		0
Electric Distribution	71	70	(2)	(0)		(1)	(0)	0	(0)
Gas Distribution	34	33	(1)	(0)		0	(0)	(0)	(1)
Safety and Security	4	4	(0)	(0)		(0)	0	0	0
Customer Services	83	87	4	(1)		2	1	3	(1)
Chief Operations Officer	**$ 469**	**$ 471**	**2**	**(3)**	**6**	**(1)**	**3**	**3**	**(5)**
General Counsel	31	33	1	(0)		2	(0)		(0)
Human Resources	7	7	1	0		0	(0)		0
General Counsel & HR	**$ 38**	**$ 40**	**2**	**0**		**2**	**(0)**		**(0)**
Information Technology	56	58	2	2		(1)	(0)		1
Supply Chain	4	4	(0)	(0)		0	0		(0)
Finance	20	20	0	(0)		0	0		1
Chief Financial Officer	**$ 79**	**$ 81**	**2**	**2**		**(1)**	**(0)**		**2**
Corporate	**$ 151**	**$ 176**	**25**	**21**		**0**	**(1)**	**0**	**4**
O&M Total YTD	**$ 736**	**$ 767**	**$ 31**	**$ 19**	**$ 6**	**$ (0)**	**$ 2**	**$ 3**	**$ 0**

Note: Schedules may not sum due to rounding.

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Financing Activities — December 2015

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance
PCB						
Beg Bal	$ 923.9	$ 923.9	$ 0.0	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	0.0	923.9	923.9	0.0
Ave Bal	**$ 923.9**	**$ 923.9**	**$ 0.0**	**$ 923.9**	**$ 923.9**	**$ 0.0**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 10.3**	**$ 13.8**	**$ 3.4**
Rate	**1.11%**	**1.44%**	**0.33%**	**1.10%**	**1.47%**	**0.37%**
FMB/Sr Nts [(1)]						
Beg Bal	$ 4,193.6	$ 4,194.3	$ 0.6	$ 3,642.7	$ 3,642.7	$ -
End Bal	4,193.7	4,194.4	0.6	4,193.7	4,194.4	0.6
Ave Bal	**$ 4,193.7**	**$ 4,194.3**	**$ 0.6**	**$ 3,918.2**	**$ 3,918.5**	**$ 0.3**
Interest Exp	**$ 15.0**	**$ 15.4**	**$ 0.4**	**$ 149.1**	**$ 149.9**	**$ 0.8**
Rate	**4.16%**	**4.27%**	**0.11%**	**3.75%**	**3.77%**	**0.02%**
Short-term Debt						
Beg Bal	$ 282.5	$ 274.5	$ (8.0)	$ 615.4	$ 615.4	$ -
End Bal	318.9	262.0	(56.9)	318.9	262.0	(56.9)
Ave Bal	**$ 300.7**	**$ 268.2**	**$ (32.5)**	**$ 467.2**	**$ 438.7**	**$ (28.5)**
Interest Exp	**$ 0.3**	**$ 0.3**	**$ 0.0**	**$ 4.2**	**$ 6.0**	**$ 1.9**
Rate	**1.16%**	**1.43%**	**0.27%**	**0.88%**	**1.36%**	**0.48%**
Total End Bal [(2)]	**$ 5,406.4**	**$ 5,354.7**	**$ (51.7)**	**$ 5,406.4**	**$ 5,354.7**	**$ (51.7)**
Total Average Bal	**$ 5,418.2**	**$ 5,386.4**	**$ (31.8)**	**$ 5,309.3**	**$ 5,253.2**	**$ (56.0)**
Total Expense Excl I/C [(3)]	**$ 17.5**	**$ 18.1**	**$ 0.6**	**$ 180.8**	**$ 186.3**	**$ 5.5**
Rate	**3.75%**	**3.91%**	**0.16%**	**3.34%**	**3.48%**	**0.14%**

(1) Include FMBs maturing in November 2015 $900m.

(2) Total ending balance and average balance includes additional unamortized debt issuance costs. Total will not match sum of PCB, FMB, and STD.

(3) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 129		$ 171
LG&E	500	142		358
KU	598	48	$ 198	352
TOTAL	$ 1,398	$ 319	$ 198	$ 881

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud
FFO to Debt - LG&E	25.9%	-7%
FFO to Debt - KU	23.9%	1%
Debt to EBITDA - LG&E [(2)]	3.56	0.07
Debt to EBITDA - KU [(2)]	3.62	-0.22
Debt to Capitalization - LG&E [(3)]	47.9%	1%
Debt to Capitalization - KU [(3)]	46.9%	0%

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet

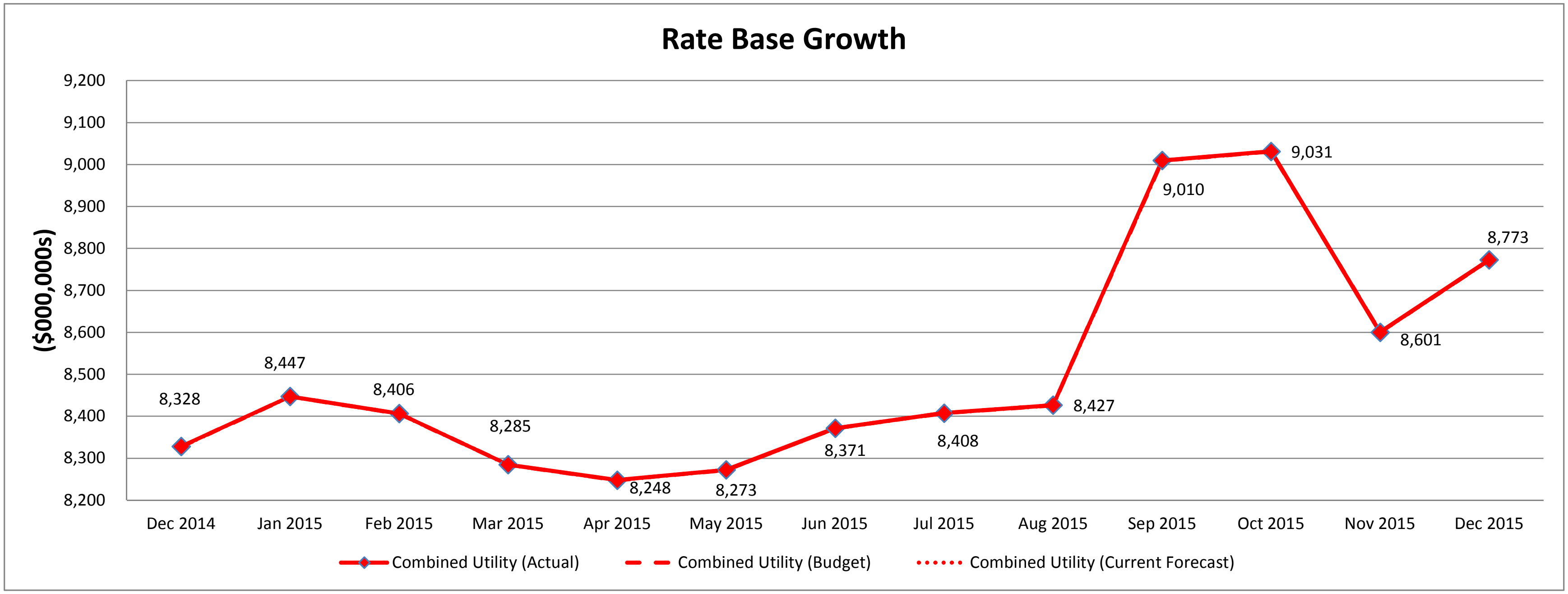
December 2015

($ Millions)

	12/31/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 30	$ 17	$ 13	Primarily due to lower dividend payments and increased borrowing than assumed in budget.
Accounts Receivable (Trade)	362	417	(55)	Lower customer accounts receivable ($36m) and accrued utility revenue ($20m).
Inventory	298	289	10	
Deferred Income Taxes	-	16	(16)	Per new accounting guidance related to deferred tax presentation, the deferred tax asset balance was netted with the deferred tax liability balance. This methodology is not reflected in the budget.
Regulatory Assets Current	35	42	(7)	
Prepayments and other current assets	39	182	(144)	Primarily related to lower income tax receivable due to tax settlement from PPL which is budgeted in accrued taxes below ($136m).
Total Current Assets	764	963	(199)	
Property, Plant, and Equipment	11,404	11,209	195	
Intangible Assets	123	124	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	727	654	72	Primarily due to increase in deferred pension expense of $37m related to current year losses and plan amendments not budgeted and methodology change as a result of the 2014 rate case. Difference also attributable to ARO activity of $29m and loss related to forward starting swaps of $20m.
Goodwill	997	997	-	
Other Long-term Assets	74	107	(33)	Primarily due to the reclassification of debt issuance costs which are now included as a contra-liability with debt per new accounting guidance. This methodology is not reflected in the budget. To see adjusted budgeted debt balance please refer to the Financing Activities schedule.
Total Assets	**$ 14,090**	**$ 14,054**	**$ 36**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 271	$ 361	$ (91)	Decreases in project engineering accruals, retail natural gas purchases and gas prices, timing of coal receipts and payments and trade payables related to winding down of construction projects.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	52	52	(0)	
Derivative Liability	5	71	(66)	Due to settlement of forward starting swaps with PPL.
Accrued Taxes	46	172	(126)	Primarily due to income tax settlement of $136m (see Prepayments and other current assets explanation above) and timing of federal payments made by LKE to PPL ($10m).
Regulatory Liabilities Current	32	12	20	Higher balance primarily due to over-recovery of fuel costs related to FAC of $14m.
Other Current Liabilities	218	164	54	Primarily related to reclassification of ARO's from noncurrent to current liability of $39m.
Total Current Liabilities	624	833	(209)	
Debt - Affiliated Company	454	446	8	
Debt [(1)]	4,952	4,934	18	
Total Debt	5,406	5,380	26	
Deferred Tax Liabilities	1,463	1,462	1	
Investment Tax Credit	128	128	0	
Accum Provision for Pension & Related Benefits	296	269	27	Primarily due to current year losses and plan amendments not budgeted of $38m partially offset by lower pension expense ($9m).
Asset Retirement Obligation	485	288	197	Due to revaluation of ARO's of $240m to reflect updates in the estimated cash flows for ash and environmental ponds primarily related to the enactment of the Coal Combustion Residuals (CCR) Rule partially offset by a reclassification of ARO from non-current to current liabilities of ($39m).
Regulatory Liabilities Non Current	923	911	12	
Derivative Liability	42	43	(1)	
Other Liabilities	205	257	(52)	Primarily due to reclassification of retainage related to CR7 project from long-term to short-term ($40m).
Total Deferred Credits and Other Liabilities	3,541	3,357	185	
Equity	4,518	4,484	34	
Total Liabilities and Equity	**$ 14,090**	**$ 14,054**	**$ 36**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

YTD	Actual	Budget	Variance	Comments
Net Income	364	353	11	
Depreciation	409	416	(7)	
Deferred Income Taxes	236	214	22	Primarily due to the impact of the extension of bonus depreciation for years 2015 through 2019 and opting to take bonus depreciation at KU. This is largely offset by a change of NOL utilization to NOL addition.
Other Balance Sheet Movements	64	95	(32)	Budget does not include non cash effect of regulatory over/under accrual adjustments.
Funds From Operations	**1073**	**1078**	**(5)**	
Changes in accounts receivables	44	(13)	57	Primarily due to a decrease in unbilled revenue and customer accounts receivable related to lower volumes driven by seasonality.
Changes in inventories	6	23	(17)	Primarily due to lower commodity costs related to lower fuel prices and lower volume usage due to decreased generation.
Change in Accounts Payable	(60)	(43)	(17)	Budget does not remove the effect of the capital expenditures accrual which is reflected in actuals.
Change in Working Capital	**(10)**	**(33)**	**23**	
Operating Cash flow	**1063**	**1045**	**18**	
Capex	(1210)	(1125)	(85)	
Other Investing	7	0	7	Due to proceeds from key man life issuance.
Loans to Affiliates	0	0	0	
Investing Cash flow	**(1203)**	**(1125)**	**(78)**	
Dividends	(219)	(251)	32	Lower dividends due to increased cash needs at LKE.
Equity Infusion	125	130	(5)	
Net Borrowings	253	197	56	Higher capex payments.
Other	(10)	0	(10)	Debt issuance and credit facility costs.
Financing Cash flow	**149**	**76**	**73**	
Net increase (decrease) in cash	**9**	**(4)**	**13**	


Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,328
8,447
8,406
8,285
8,248
8,273
8,371
8,408
8,427
9,010
9,031
8,601
8,773
Dec 2014
Jan 2015
Feb 2015
Mar 2015
Apr 2015
May 2015
Jun 2015
Jul 2015
Aug 2015
Sep 2015
Oct 2015
Nov 2015
Dec 2015
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

Combined KU and LG&E ROE — December 2015

KU and LG&E Combined

Reconciliation of Allowed Return to

12 months ended Dec-2015 Regulatory Return

and ROE from Ongoing Operations

Allowed Return [1]		10.14%	
Adjustments (net of tax):			
Change in capitalization - non mechanism	-0.83%		Growth in capitalization (rate base) between rate cases does not earn a return (1st half of year)
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.02%		
Change in margins	0.79%		Primarily new rates based on last rate cases
Change in allowed expenses	-0.69%		Inflationary Increases
		-0.75%	
Actual Regulated ROE		9.39%	

(1) Based on the most recent base rate filings with test years ending 6/30/16 KPSC, 12/31/13 FERC, 12/31/12 VA.

Note: The allowed return is a blended rate of the previous authorized ROE of 10.25% before 7/1/15 and from the settlement for TYE 6/30/16 which did not provide a specific return on equity with respect to base rates; however, the average customer's monthly bill will reflect an authorized 10 percent return on equity investment related to the environmental cost recovery mechanism and the gas line tracker mechanism.

Performance Report

January 2016

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Kentucky Regulated Dashboard — January 2016

	Current Month		Full Year	
Safety[1]	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.90	1.22	1.38	1.22
Employee lost-time incidents	0	0	9	8
Reliability	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,175	3,290	34,849	34,964
Utility EFOR	2.6%	5.7%	N/A	5.7%
Utility EAF	93.4%	93.4%	N/A	82.3%
Steam Fleet Commercial Availability	98.3%	92.8%	N/A	92.8%
Combined SAIFI	0.07	0.09	N/A	1.03
Combined SAIDI (minutes)	7.27	8.16	N/A	94.09
GwH Sales				
Residential	1,242	1,154	10,935	10,847
Commercial	666	667	7,792	7,793
Industrial	721	821	9,989	10,089
Municipals	175	173	1,888	1,886
Other	228	242	2,784	2,798
Off-System Sales	27	97	181	322
Total	3,059	3,154	33,569	33,735
Weather-Normalized Sales Growth	**TTM**			
Residential	-1.25%			
Commercial	-0.24%			
Industrial	-2.74%			
Municipal	0.24%			
Other	-0.25%			
Total	-1.30%			

	Current Month		Full Year	
Financial Metrics	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	15.4%	14.4%	9.8%	9.8%
Electric Margins	$171	$167	$1,868	$1,870
Gas Margins	24	25	174	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$2	$5	$9	$9
ECR	16	30	404	404
Generation	5	5	117	117
Transmission	4	5	90	90
Electric Distribution	9	10	169	169
Gas Distribution	5	6	86	86
Customer Services	1	2	20	20
IT and Other	5	4	59	59
Total	$47	$66	$955	$955
O&M ($ millions)[3]	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$32	$33	$459	$459
General Counsel & HR	3	3	42	42
Finance, IT, & Supply Chain	7	7	85	86
Burdens & Other Charges	11	12	144	144
Total	$52	$55	$730	$731
Head Count	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,467	3,552	3,600	3,600
Other Metrics	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	N/A	16
NERC Possible Violations[4]	0	1	N/A	8

Major Developments

• LG&E and KU submitted to the Kentucky Public Service Commission (KPSC) Environmental Cost Recovery (ECR) filings for recovery of costs (approximately $1 billion) largely attributable to the EPA's Coal Combustion Residuals (CCR) rule. LG&E and KU also requested approval for Certificates of Public Convenience and Necessity from the KPSC for closure of CCR impoundments at all of the utilities' generating stations (active and inactive).

• The Virginia State Corporation Commission issued an Order approving the stipulation in the Virginia rate case without exception. The new rates were put into effect February 15.

• LG&E and KU has performed well in recent customer satisfaction surveys. LG&E and KU achieved first place in the 4Q 2015 Residential Customer Satisfaction Survey. In the J.D. Power 2016 Electric Utility Business Study, KU came in 2nd and LG&E finished 6th, respectively, in the Midwest Midsize segment. LG&E also ranked third among the Midwest region in the J.D. Power 2016 Gas Utility Business Study.

• LG&E and KU took the next step in our plan to offer small-scale solar arrays to business and industrial customers by issuing a request for proposal. This step follows the request for information process where the Company received 10 responses from local and national companies with expertise in solar generation design and construction. LG&E and KU will own and operate the individual solar facilities and each project will be subject to approval by the KPSC. The facilities will likely range in size from 30 kilowatts to 5 megawatts.

Significant Future Events

• The Mill Creek 3 baghouse construction is progressing toward an April 2016 tie-in outage. The unit will be restarted during June 2016 in compliance with the Mercury and Air Toxics Standards rule.

• Construction of the Brown Solar project is underway and the facility is expected to be commercially operational by late spring of 2016.

(1) Full year forecast amount shown represents target.

(2) Excludes goodwill and other purchase accounting adjustments.

(3) Net of cost recovery mechanisms.

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — January 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 264	$ 271	$ (7)	Due to lower fuel costs and slightly lower sales volumes for the month as higher Residential volumes were offset by lower Industrial volumes.
Gas Revenues	50	56	(7)	See Gas Supply Expenses explanation below.
Total Revenues	314	327	(13)	
Cost of Sales:				
Fuel Electric Costs	78	85	7	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	25	31	6	Due to lower net purchases and lower gas prices.
Purchased Power	4	5	1	
Other Electric Cost	12	14	3	
Total Cost of Sales	119	135	16	
Gross Margin:				
Electric Margin	171	167	4	
Gas Margin	24	25	(1)	
Total Gross Margin	195	192	2	
Operating Expenses:				
O&M	52	55	3	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	86	90	4	
Other income (expense)	(1)	(1)	0	
EBIT	108	102	6	
Interest Expense	18	18	1	
Income from Ongoing Operations before income taxes	90	83	7	
Income Tax Expense	34	32	(2)	
Net Income (loss) from ongoing operations	**56**	**51**	**$ 4**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 56	$ 51	$ 4	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 53	$ 49	$ 4	
Earnings Per Share - Ongoing	$ 0.08	$ 0.07	$ 0.01	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E

January 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 98	$ 99	$ (2)	
Gas Revenues	50	56	(7)	See Gas Supply Expenses explanation below.
Total Revenues	147	155	(8)	
Cost of Sales:				
Fuel Electric Costs	30	32	2	
Gas Supply Expenses	25	31	6	Due to lower net purchases and lower gas prices.
Purchased Power	3	4	1	
Other Electric Cost	4	6	1	
Total Cost of Sales	63	73	10	
Gross Margin:				
Electric Margin	60	57	3	
Gas Margin	25	25	(1)	
Total Gross Margin	84	83	2	
Operating Expenses:				
O&M	23	25	1	
Depreciation & Amortization	12	12	0	
Taxes, Other than Income	2	2	0	
Total Operating Expenses	37	39	2	
Other income (expense)	(0)	(0)	0	
EBIT	47	43	4	
Interest Expense	6	6	0	
Income from Ongoing Operations before income taxes	41	37	4	
Income Tax Expense	16	14	(1)	
Net Income (loss) from ongoing operations	**25**	**23**	**$ 2**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

January 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 172	$ 179	$ (8)	Due to lower fuel costs and slightly lower sales volumes for the month as higher Residential volumes were offset by lower Industrial volumes.
Gas Revenues	-	-	-	
Total Revenues	172	179	(8)	
Cost of Sales:				
Fuel Electric Costs	48	54	6	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	-	-	-	
Purchased Power	6	7	1	
Other Electric Cost	7	9	1	
Total Cost of Sales	61	70	9	
Gross Margin:				
Electric Margin	111	110	1	
Gas Margin	-	-	-	
Total Gross Margin	111	110	1	
Operating Expenses:				
O&M	28	29	1	
Depreciation & Amortization	17	18	0	
Taxes, Other than Income	2	2	0	
Total Operating Expenses	47	49	2	
Other income (expense)	(1)	(1)	0	
EBIT	63	60	3	
Interest Expense	8	8	0	
Income from Ongoing Operations before income taxes	55	52	3	
Income Tax Expense	21	20	(1)	
Net Income (loss) from ongoing operations	**34**	**32**	**$ 2**	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD — January 2016

LKE Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 99,320	$ 95,885	$ 3,436
Demand	43,533	44,581	(1,048)
Base Service Charge	13,702	13,705	(4)
Rate Mechanisms	14,378	14,768	(390)
Other Rev/Cost of Sales	(288)	(1,037)	749
Other Margin Items	(69)	(926)	857
	$ 170,575	$ 166,976	$ 3,600

LG&E Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 33,574	$ 32,367	$ 1,207
Demand	13,949	14,056	(107)
Base Service Charge	5,575	5,626	(51)
Rate Mechanisms	7,554	6,962	592
Other Rev/Cost of Sales	(20)	(327)	306
Other Margin Items	(755)	(1,402)	646
	$ 59,876	$ 57,282	$ 2,594

KU Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 65,747	$ 63,518	$ 2,229
Demand	29,583	30,525	(941)
Base Service Charge	8,127	8,080	47
Rate Mechanisms	6,824	7,806	(982)
Other Rev/Cost of Sales	(267)	(710)	443
Other Margin Items	686	475	211
	$ 110,700	$ 109,694	$ 1,006

LKE Base Energy Price/Vol Variance

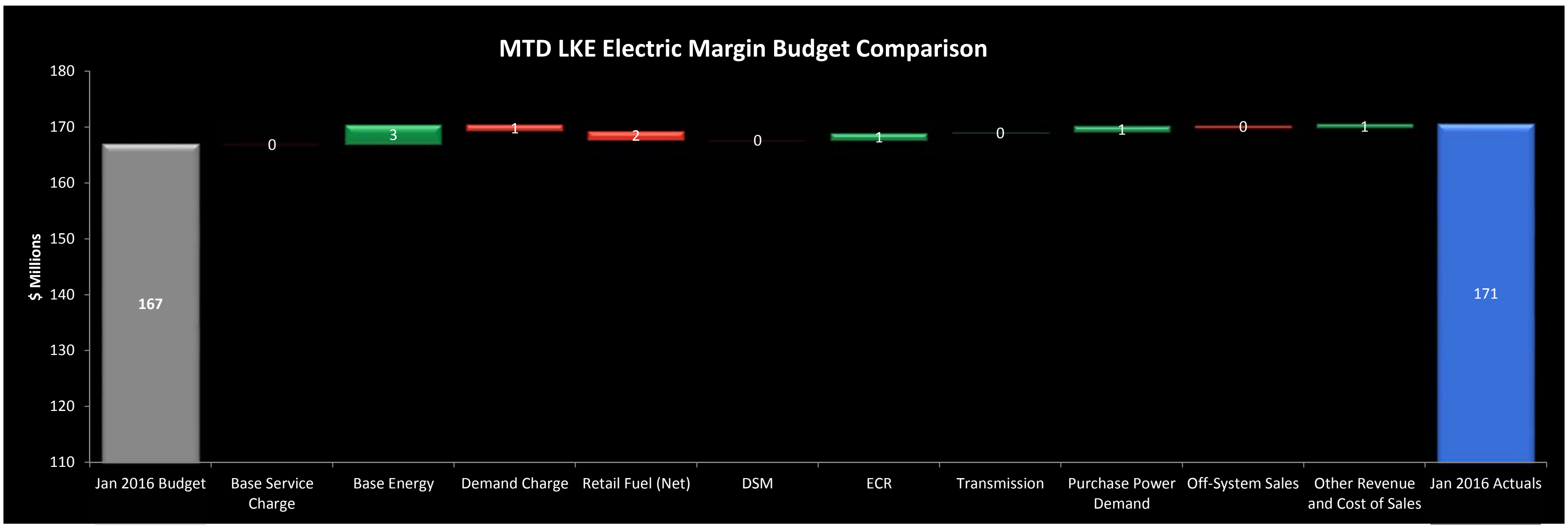
(In Thousands)	Volume	Price	Total Variance
Residential	4,619	537	5,157
Commercial	(41)	(885)	(926)
Industrial	(853)	197	(656)
Public Authority	(258)	126	(132)
Street Lights	(101)	421	320
Municipals	17	(343)	(327)
Other	-	-	-
	$ 3,382	$ 53	$ 3,436

LG&E Base Energy Price/Vol Variance

(In Thousands)	Volume	Price	Total Variance
Residential	1,195	266	1,461
Commercial	180	(293)	(113)
Industrial	(447)	105	(342)
Public Authority	(69)	190	121
Street Lights	21	59	80
Municipals	-	-	-
Other	-	-	-
	$ 880	$ 327	$ 1,207

KU Base Energy Price/Vol Variance

(In Thousands)	Volume	Price	Total Variance
Residential	3,424	271	3,696
Commercial	(221)	(592)	(813)
Industrial	(406)	92	(314)
Public Authority	(189)	(64)	(253)
Street Lights	(122)	363	240
Municipals	17	(343)	(327)
Other	-	-	-
	$ 2,503	$ (274)	$ 2,229



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

Gas Gross Margin — January 2016

($ Millions)

	MTD			
	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**0**
Gas Supply Costs				
Gas Supply Costs	(24)	(30)	$ 6	
GSC Revenue	24	30	$ (6)	
Net Gas Supply Costs				**0**
Retail Gas (a)	**18**	**19**		**(1)**
Wholesale Gas (a)	**-**	**-**		**-**
DSM	**0**	**0**		**(0)**
GLT	**-**	**-**		**-**
WNA	**0**	**-**		**0**
Other Margin	**1**	**1**		**(0)**
Gas Margin Variance				**$ (1)**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 12	4,275,642	$ 2.87	$ 13	4,471,615	$ 2.87	($0.6)	($0.6)	($0.0)
Commercial	4	1,825,414	2.15	4	1,810,210	2.15	$0.0	$0.0	($0.0)
Industrial	0	157,121	2.25	0	192,782	2.19	($0.1)	($0.1)	$0.0
Public Authority	1	266,739	2.11	1	277,428	2.13	($0.0)	($0.0)	($0.0)
Transportation	1	1,589,601	0.52	1	1,528,969	0.48	$0.1	$0.0	$0.1
Interdepartmental	0	28,170	10.76	0	12,722	23.42	$0.0	$0.4	($0.4)
Ultimate Consumer	$ 18	8,142,687	$ 2.24	$ 19	8,293,726	$ 2.26	($0.5)	($0.2)	($0.3)

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	$ 13	$ 14	$ 1	0	0	0	0	(0)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	2	0	(0)	0	(0)	0	0
Energy Supply and Analysis	1	1	0	0	-	0	0	0
Generation Services	1	1	0	0	(0)	0	(0)	(0)
Electric Distribution	5	6	0	(0)	1	(0)	0	0
Gas Distribution	3	3	0	(0)	0	(0)	(0)	0
Safety and Security	0	0	0	0	(0)	0	0	0
Customer Services	7	7	0	0	0	0	(0)	(0)
Chief Operations Officer	**32**	**33**	**1**	**(0)**	**1**	**0**	**0**	**(0)**
General Counsel	2	2	0	(0)	(0)	0	0	0
Human Resources	1	1	(0)	(0)	-	(0)	(0)	(0)
General Counsel & HR	**3**	**3**	**0**	**(0)**	**(0)**	**0**	**0**	**0**
Audit Services	0	0	0	0	-	0	0	0
Controller	1	1	0	0	0	(0)	0	0
Information Technology	5	5	0	0	0	(0)	0	0
Supply Chain	0	0	(0)	(0)	-	0	0	(0)
Treasurer	1	1	0	(0)	-	(0)	0	0
Chief Financial Officer	**7**	**7**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**11**	**12**	**1**	**1**	**(0)**	**0**	**(0)**	**0**
O&M Total MTD	**$ 52**	**$ 55**	**$ 3**	**1**	**1**	**0**	**1**	**0**

Note: Schedules may not sum due to rounding.

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Financing Activities — January 2016

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance
PCB			
Beg Bal	$ 923.9	$ 923.9	$ -
End Bal	923.9	923.9	0.0
Ave Bal	**$ 923.9**	**$ 923.9**	**$ 0.0**
Interest Exp	**$ 0.9**	**$ 1.2**	**$ 0.2**
Rate	**1.19%**	**1.45%**	**0.26%**
FMB/Sr Nts			
Beg Bal	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 15.0**	**$ 14.6**	**$ (0.4)**
Rate	**4.14%**	**4.03%**	**-0.11%**
Short-term Debt			
Beg Bal	$ 318.9	$ 318.9	$ -
End Bal	339.2	288.5	(50.8)
Ave Bal	**$ 329.1**	**$ 303.7**	**$ (25.4)**
Interest Exp	**$ 0.3**	**$ 0.5**	**$ 0.1**
Rate	**1.19%**	**1.76%**	**0.57%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (46.3)	$ (46.3)	$ -
End Bal	(46.0)	(45.6)	0.4
Ave Bal	**$ (46.2)**	**$ (46.0)**	**$ 0.2**
Total End Bal	**$ 5,427.1**	**$ 5,376.7**	**$ (50.4)**
Total Average Bal	**$ 5,416.8**	**$ 5,391.6**	**$ (25.2)**
Total Expense Excl I/C (1)	**$ 17.6**	**$ 18.1**	**$ 0.5**
Rate	**3.74%**	**3.88%**	**0.13%**

(1) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed (2)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 137		$ 163
LG&E	500	159		341
KU	598	43	$ 198	357
TOTAL	$ 1,398	$ 339	$ 198	$ 861

(2) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics(1) Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	17%	18%	26%	28%	24%	24%
CFO pre-WC + Interest / Interest	5.9	6.1	8.98	9.3	7.7	7.7
CFO pre-WC - Dividends / Debt	15%	15%	25%	26%	17%	18%
Debt to Capitalization(2)	49%	48%	40%	39%	39%	39%

Credit Metrics Moody's	LKE - 2016 BP 2017	LKE - 2016 BP 2018	LG&E 2016 BP 2016	LG&E 2016 BP 2017	KU 2016 BP 2016	KU 2016 BP 2017
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization(2)	46%	45%	37%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — January 2016

($ Millions)

	1/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 25	$ 14	$ 11	Primarily due to lower capital expenditures and increase in cash from financing.
Accounts Receivable (Trade)	430	420	10	
Inventory	280	272	8	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	34	43	(9)	
Prepayments and other current assets	37	40	(3)	
Total Current Assets	806	789	17	
Property, Plant, and Equipment	11,412	11,432	(20)	
Intangible Assets	121	119	2	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	737	729	9	
Goodwill	997	997	-	
Other Long-term Assets	76	75	1	
Total Assets	**$ 14,150**	**$ 14,142**	**$ 8**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 243	$ 279	$ (36)	Primarily related to decreases in project engineering accruals and timing of payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	52	52	0	
Derivative Liability	6	5	1	
Accrued Taxes	76	83	(7)	
Regulatory Liabilities Current	26	32	(5)	
Other Current Liabilities	226	235	(8)	
Total Current Liabilities	630	685	(55)	
Debt - Affiliated Company	462	465	(3)	
Debt [(1)]	4,965	4,911	54	
Total Debt	5,427	5,377	50	
Deferred Tax Liabilities	1,463	1,463	(0)	
Investment Tax Credit	127	127	0	
Accum Provision for Pension & Related Benefits	268	266	1	
Asset Retirement Obligation	486	487	(0)	
Regulatory Liabilities Non Current	921	919	2	
Derivative Liability	47	42	5	
Other Liabilities	207	206	1	
Total Deferred Credits and Other Liabilities	3,519	3,511	9	
Equity	4,574	4,570	4	
Total Liabilities and Equity	**$ 14,150**	**$ 14,142**	**$ 8**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

January 2016

($ Millions)

	1/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 14	$ 5	$ 9	
Accounts Receivable (Trade)	191	189	2	
Inventory	134	121	13	Primarily due to increased coal purchases.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	17	15	1	
Prepayments and other current assets	34	35	(0)	
Total Current Assets	390	365	24	
Property, Plant, and Equipment	4,802	4,818	(17)	
Intangible Assets	6	5	1	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	428	421	7	
Goodwill	-	-	-	
Other Long-term Assets	17	17	0	
Total Assets	**$ 5,644**	**$ 5,628**	**$ 16**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 166	$ 187	$ (21)	Decrease primarily due to timing of outstanding checks, cash funding and payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	0	
Derivative Liability	6	5	1	
Accrued Taxes	32	37	(5)	
Regulatory Liabilities Current	11	13	(2)	
Other Current Liabilities	78	81	(3)	
Total Current Liabilities	318	349	(31)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,800	1,762	38	
Total Debt	1,800	1,762	38	
Deferred Tax Liabilities	828	828	(0)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	45	44	1	
Asset Retirement Obligation	150	150	(0)	
Regulatory Liabilities Non Current	364	364	(0)	
Derivative Liability	47	42	5	
Other Liabilities	92	91	1	
Total Deferred Credits and Other Liabilities	1,560	1,553	7	
Equity	1,965	1,963	2	
Total Liabilities and Equity	**$ 5,644**	**$ 5,628**	**$ 16**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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Balance Sheet - KU

January 2016

($ Millions)

	1/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 10	$ 5	$ 5	
Accounts Receivable (Trade)	238	229	9	
Inventory	147	151	(5)	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	17	28	(10)	Decrease due to lower balances related to FAC and ECR.
Prepayments and other current assets	12	17	(4)	
Total Current Assets	424	430	(6)	
Property, Plant, and Equipment	6,603	6,607	(3)	
Intangible Assets	13	12	1	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	303	302	1	
Goodwill	-	-	-	
Other Long-term Assets	49	49	1	
Total Assets	**$ 7,394**	**$ 7,399**	**$ (6)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 118	$ 132	$ (14)	Primarily related to decreases in project engineering accruals and timing of payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	27	26	0	
Derivative Liability	-	-	-	
Accrued Taxes	37	42	(5)	
Regulatory Liabilities Current	15	18	(3)	
Other Current Liabilities	89	93	(3)	
Total Current Liabilities	285	311	(26)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,366	2,350	16	
Total Debt	2,366	2,350	16	
Deferred Tax Liabilities	1,047	1,047	(0)	
Investment Tax Credit	93	93	0	
Accum Provision for Pension & Related Benefits	38	37	0	
Asset Retirement Obligation	337	337	(0)	
Regulatory Liabilities Non Current	455	453	2	
Derivative Liability	-	-	-	
Other Liabilities	60	60	0	
Total Deferred Credits and Other Liabilities	2,029	2,027	2	
Equity	2,713	2,712	2	
Total Liabilities and Equity	**$ 7,394**	**$ 7,399**	**$ (6)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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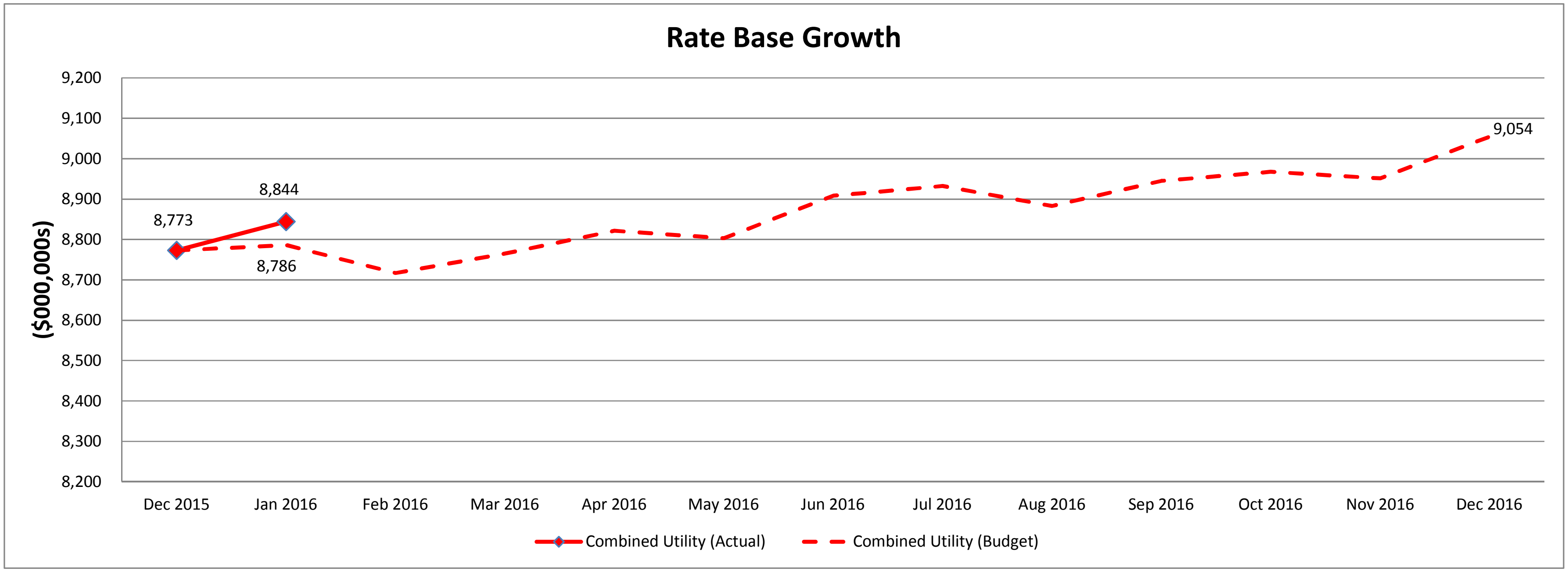
Rate Base Growth
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
($000,000s)
8,773
8,844
8,786
9,054
Dec 2015
Jan 2016
Feb 2016
Mar 2016
Apr 2016
May 2016
Jun 2016
Jul 2016
Aug 2016
Sep 2016
Oct 2016
Nov 2016
Dec 2016
Combined Utility (Actual)
Combined Utility (Budget)

Performance Report

February 2016

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Kentucky Regulated Dashboard

February 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.37	1.43	0.61	1.34	1.38	1.22
Employee lost-time incidents	0	0	0	0	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,771	2,960	5,946	6,249	34,660	34,964
Utility EFOR	3.3%	5.7%	2.9%	5.7%	N/A	5.7%
Utility EAF	92.5%	94.1%	93.1%	94.1%	N/A	82.3%
Steam Fleet Commercial Availability	99.0%	92.8%	98.7%	92.8%	N/A	92.8%
Combined SAIFI	0.04	0.05	0.11	0.14	N/A	1.03
Combined SAIDI (minutes)	3.76	5.03	11.03	13.19	N/A	94.09
GwH Sales						
Residential	913	996	2,155	2,150	10,852	10,847
Commercial	622	601	1,288	1,268	7,814	7,793
Industrial	776	752	1,497	1,573	10,013	10,089
Municipals	155	156	330	329	1,886	1,886
Other	226	218	454	460	2,792	2,798
Off-System Sales	6	109	33	206	140	322
Total	2,698	2,832	5,757	5,986	33,497	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.29%			
Commercial			0.44%			
Industrial			-2.91%			
Municipal			0.71%			
Other			0.89%			
Total			-1.40%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	11.4%	11.6%	13.4%	12.9%	9.8%	9.8%
Electric Margins	$152	$155	$323	$322	$1,868	$1,870
Gas Margins	22	22	46	48	174	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$7	$1	$9	$6	$16	$9
ECR	7	29	23	59	377	404
Generation	5	9	10	14	128	117
Transmission	5	7	9	11	91	90
Electric Distribution	12	12	21	22	172	169
Gas Distribution	5	6	10	11	88	86
Customer Services	2	1	2	3	20	20
IT and Other	4	5	9	8	62	59
Total	$46	$69	$93	$135	$954	$955
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$35	$36	$67	$69	$459	$459
General Counsel & HR	3	4	6	7	42	42
Finance, IT, & Supply Chain	7	7	13	14	85	86
Burdens & Other Charges	14	14	25	26	144	144
Total	$59	$60	$112	$116	$730	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,457	3,556	3,457	3,556	3,600	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	7	0	7	N/A	16
NERC Possible Violations[4]	0	0	0	1	N/A	8

Variance Explanations

• Current month and YTD capital expenditures were lower, primarily due to the timing of Environmental Cost Recovery (ECR) spending on Environmental Air projects at Mill Creek.

Major Developments

• LKE continues its strong safety performance in 2016. Ohio Falls' employees achieved a significant milestone as they recently celebrated 10,000 days without a lost-time incident. The accomplishment was quite extraordinary considering the amount of major unit upgrades that have occurred during the period. EEI also presented a safety award to Distribution Operations employees in London, Kentucky, for over 250,000 hours without a lost work day.

• The Kentucky Public Service Commission (KPSC) issued procedural schedules in the Environmental Cost Recovery (ECR) plan proceedings and LG&E and KU will receive initial data requests in March.

Significant Future Events

• The Mill Creek 3 baghouse construction is progressing toward an April 2016 tie-in outage. The unit will be restarted during June 2016 in compliance with the Mercury and Air Toxics Standards (MATS) rule.

• Construction of the Brown Solar project is progressing and the facility is expected to be commercially operational by late spring of 2016.

• Regarding the ECR plan proceedings, intervenor testimony will be filed in May, and a formal hearing is expected in June.

(1) Full year forecast amount shown represents target.

(2) Excludes goodwill and other purchase accounting adjustments.

(3) Net of cost recovery mechanisms.

(4) The possible violation issues are believed to be minimal risk.

Income Statement: Actual vs. Budget (Month)

February 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 234	$ 250	$ (16)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	41	49	(8)	See Gas Supply Expenses explanation below.
Total Revenues	275	299	(24)	
Cost of Sales:				
Fuel Electric Costs	65	77	12	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	19	26	7	Due to lower net purchases and lower gas prices.
Purchased Power	5	4	(0)	
Other Electric Cost	12	14	2	
Total Cost of Sales	101	121	20	
Gross Margin:				
Electric Margin	152	155	(3)	
Gas Margin	22	22	(0)	
Total Gross Margin	174	178	(3)	
Operating Expenses:				
O&M	59	60	1	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	92	95	2	
Other income (expense)	(1)	(1)	(1)	
EBIT	81	83	(1)	
Interest Expense	17	18	1	
Income from Ongoing Operations before income taxes	63	64	(1)	
Income Tax Expense	24	25	1	
Net Income (loss) from ongoing operations	**39**	**40**	**$ (0)**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 39	$ 40	$ (0)	
KY Regulated Financing Costs	(2)	(2)	(0)	
KY Regulated Net Income	$ 37	$ 37	$ (0)	
Earnings Per Share - Ongoing	$ 0.05	$ 0.05	$ (0.00)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated				**February 2016**
($ Millions)				
	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 498	$ 521	$ (23)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	91	105	(14)	See Gas Supply Expenses explanation below.
Total Revenues	589	626	(37)	
Cost of Sales:				
Fuel Electric Costs	143	162	19	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	44	57	13	Due to lower net purchases and lower gas prices.
Purchased Power	9	9	0	
Other Electric Cost	24	28	5	Due to lower ECR expense and scrubber reactant expense.
Total Cost of Sales	220	256	36	
Gross Margin:				
Electric Margin	323	322	1	
Gas Margin	46	48	(1)	
Total Gross Margin	369	370	(1)	
Operating Expenses:				
O&M	112	116	4	
Depreciation & Amortization	58	59	2	
Taxes, Other than Income	9	9	0	
Total Operating Expenses	178	184	6	
Other income (expense)	(2)	(2)	(0)	
EBIT	189	184	5	
Interest Expense	35	36	1	
Income from Ongoing Operations before income taxes	154	148	6	
Income Tax Expense	59	57	(2)	
Net Income (loss) from ongoing operations	**95**	**91**	**$ 4**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 95	$ 91	$ 4	
KY Regulated Financing Costs	(5)	$ (5)	(0)	
KY Regulated Net Income	$ 90	$ 86	$ 4	
Earnings Per Share - Ongoing	$ 0.13	$ 0.13	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E				February 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 185	$ 191	$ (6)	Primarily due to lower offsystem sales.
Gas Revenues	91	105	(14)	See Gas Supply Expenses explanation below.
Total Revenues	276	295	(20)	
Cost of Sales:				
Fuel Electric Costs	57	61	5	Primarily due to lower offsystem related fuel costs.
Gas Supply Expenses	44	57	13	Due to lower net purchases and lower gas prices.
Purchased Power	7	7	1	
Other Electric Cost	9	11	2	
Total Cost of Sales	116	137	21	
Gross Margin:				
Electric Margin	113	111	2	
Gas Margin	46	48	(1)	
Total Gross Margin	160	159	1	
Operating Expenses:				
O&M	49	51	1	
Depreciation & Amortization	23	24	1	
Taxes, Other than Income	4	5	0	
Total Operating Expenses	77	79	2	
Other income (expense)	(1)	(1)	(0)	
EBIT	81	79	3	
Interest Expense	12	12	0	
Income from Ongoing Operations before income taxes	70	67	3	
Income Tax Expense	27	26	(1)	
Net Income (loss) from ongoing operations	**43**	**41**	**$ 2**	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - KU

February 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 322	$ 344	$ (23)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	-	-	-	
Total Revenues	322	344	(23)	
Cost of Sales:				
Fuel Electric Costs	86	103	17	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	-	-	-	
Purchased Power	10	12	2	
Other Electric Cost	15	17	2	
Total Cost of Sales	112	133	21	
Gross Margin:				
Electric Margin	210	211	(1)	
Gas Margin	-	-	-	
Total Gross Margin	210	211	(1)	
Operating Expenses:				
O&M	57	59	2	
Depreciation & Amortization	34	35	1	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	96	99	3	
Other income (expense)	(1)	(1)	0	
EBIT	113	111	1	
Interest Expense	16	16	1	
Income from Ongoing Operations before income taxes	97	95	2	
Income Tax Expense	37	37	(1)	
Net Income (loss) from ongoing operations	**60**	**59**	**$ 1**	

Note: Schedules may not sum due to rounding.

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Electric Gross Margin Analysis - MTD — February 2016

LKE Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 81,096	$ 84,858	$ (3,762)
Demand	43,337	43,791	(454)
Base Service Charge	13,719	13,709	11
Rate Mechanisms	16,075	14,988	1,088
Other Rev/Cost of Sales	(435)	(819)	384
Other Margin Items	(1,461)	(1,215)	(246)
	$ 152,332	$ 155,312	$ (2,979)

LG&E Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 28,491	$ 29,034	$ (544)
Demand	13,912	13,552	361
Base Service Charge	5,576	5,628	(52)
Rate Mechanisms	6,910	7,171	(261)
Other Rev/Cost of Sales	9	(245)	255
Other Margin Items	(1,766)	(1,525)	(240)
	$ 53,132	$ 53,614	$ (482)

KU Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 52,606	$ 55,824	$ (3,219)
Demand	29,425	30,239	(815)
Base Service Charge	8,144	8,081	63
Rate Mechanisms	9,165	7,816	1,349
Other Rev/Cost of Sales	(444)	(574)	130
Other Margin Items	305	310	(6)
	$ 99,200	$ 101,698	$ (2,498)

LKE Base Energy Price/Vol Variance

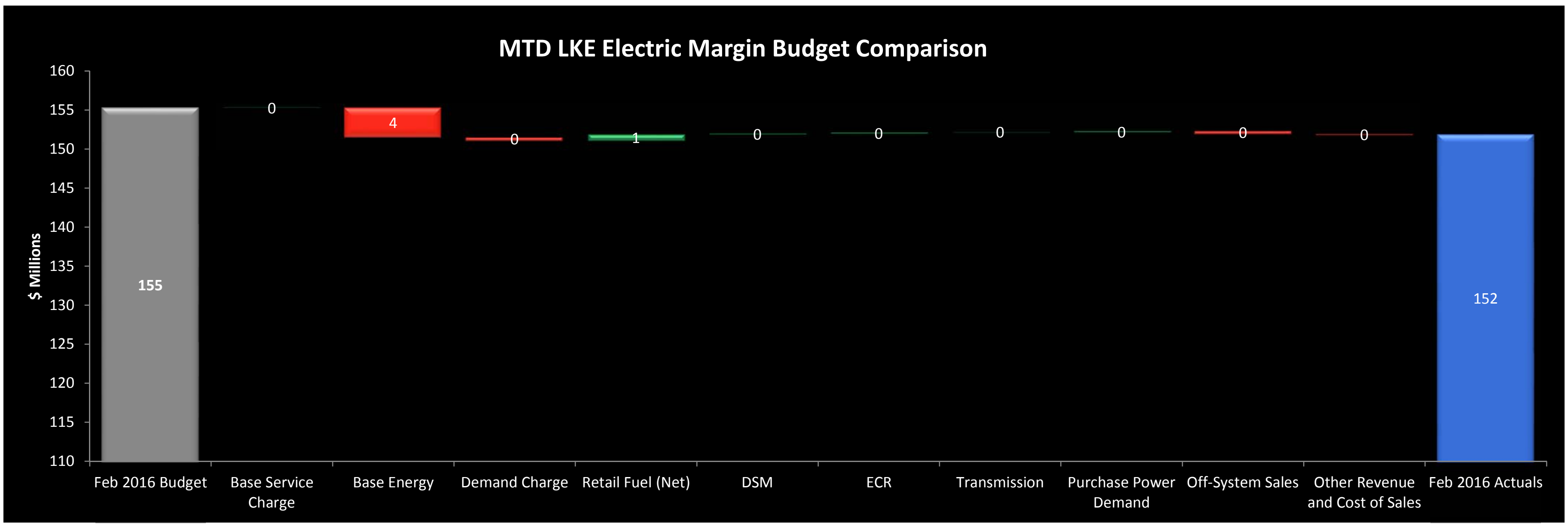
(In Thousands)	Volume	Price	Total Variance
Residential	(4,406)	420	(3,986)
Commercial	662	(498)	165
Industrial	138	107	244
Public Authority	170	147	316
Street Lights	(66)	(197)	(262)
Municipals	(12)	(228)	(240)
Other	-	-	-
	$ (3,514)	$ (248)	$ (3,762)

LG&E Base Energy Price/Vol Variance

(In Thousands)	Volume	Price	Total Variance
Residential	(1,261)	205	(1,056)
Commercial	613	(286)	327
Industrial	(59)	95	36
Public Authority	(41)	202	161
Street Lights	(12)	(0)	(13)
Municipals	-	-	-
Other	-	-	-
	$ (760)	$ 217	$ (544)

KU Base Energy Price/Vol Variance

(In Thousands)	Volume	Price	Total Variance
Residential	(3,145)	215	(2,930)
Commercial	49	(212)	(162)
Industrial	196	12	208
Public Authority	211	(56)	155
Street Lights	(53)	(196)	(249)
Municipals	(12)	(228)	(240)
Other	-	-	-
	$ (2,754)	$ (465)	$ (3,219)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Electric Gross Margin Analysis - YTD

February 2016

LKE Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 180,416	$ 180,743	$ (327)
Demand	86,870	88,372	(1,502)
Base Service Charge	27,421	27,414	7
Rate Mechanisms	30,453	29,756	698
Other Rev/Cost of Sales	(722)	(1,856)	1,134
Other Margin Items	(1,531)	(2,141)	611
	$ 322,908	$ 322,287	$ 620

LG&E Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 62,064	$ 61,401	$ 663
Demand	27,861	27,608	254
Base Service Charge	11,151	11,253	(103)
Rate Mechanisms	14,464	14,133	331
Other Rev/Cost of Sales	(11)	(572)	561
Other Margin Items	(2,521)	(2,927)	406
	$ 113,008	$ 110,896	$ 2,112

KU Electric Margin

(In Thousands)	Actual	Budget	Variance
Base Energy	$ 118,352	$ 119,342	$ (990)
Demand	59,008	60,764	(1,756)
Base Service Charge	16,271	16,161	110
Rate Mechanisms	15,989	15,622	367
Other Rev/Cost of Sales	(711)	(1,284)	573
Other Margin Items	991	786	205
	$ 209,900	$ 211,391	$ (1,492)

LKE Base Energy Price/Vol Variance

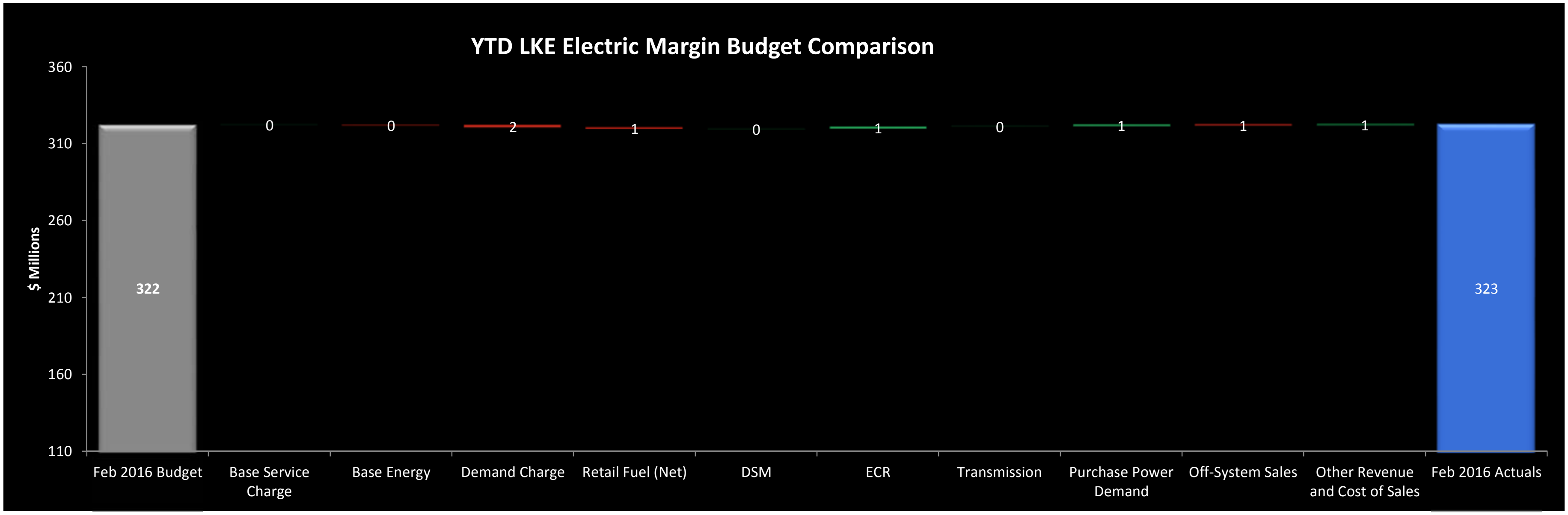
(In Thousands)	Volume	Price	Total Variance
Residential	225	946	1,171
Commercial	615	(1,377)	(762)
Industrial	(716)	305	(412)
Public Authority	(91)	275	184
Street Lights	(177)	235	58
Municipals	5	(571)	(567)
Other	-	-	-
	$ (139)	$ (187)	$ (327)

LG&E Base Energy Price/Vol Variance

(In Thousands)	Volume	Price	Total Variance
Residential	(66)	471	406
Commercial	789	(575)	214
Industrial	(507)	201	(306)
Public Authority	(111)	393	282
Street Lights	13	54	67
Municipals	-	-	-
Other	-	-	-
	$ 119	$ 544	$ 663

KU Base Energy Price/Vol Variance

(In Thousands)	Volume	Price	Total Variance
Residential	290	475	766
Commercial	(174)	(801)	(976)
Industrial	(209)	103	(106)
Public Authority	20	(118)	(98)
Street Lights	(190)	181	(9)
Municipals	5	(571)	(567)
Other	-	-	-
	$ (258)	$ (731)	$ (990)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin — February 2016

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**0**	**$ 10**	**$ 10**		**0**
Gas Supply Costs								
Gas Supply Costs	(18)	(25)	$ 7		(42)	(55)	$ 13	
GSC Revenue	18	25	$ (7)		42	55	$ (13)	
Net Gas Supply Costs				**(0)**				**0**
Retail Gas (a)	**14**	**16**		**(2)**	**32**	**35**		**(2)**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**-**
DSM	**(0)**	**0**		**(0)**	**(0)**	**0**		**(0)**
GLT	**1**	**1**		**0**	**2**	**2**		**(0)**
WNA	**1**	**-**		**1**	**1**	**-**		**1**
Other Margin	**1**	**1**		**0**	**2**	**2**		**(0)**
Gas Margin Variance				**$ (0)**				**$ (1)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 9	3,258,888	$ 2.87	$ 11	3,767,790	$ 2.87	($1.5)	($1.5)	$0.0
Commercial	3	1,431,682	2.15	3	1,528,771	2.15	($0.2)	($0.2)	$0.0
Industrial	0	125,923	2.25	0	166,459	2.18	($0.1)	($0.1)	$0.0
Public Authority	0	207,045	2.13	1	234,784	2.13	($0.1)	($0.1)	$0.0
Transportation	1	1,378,500	0.52	1	1,302,969	0.46	$0.1	$0.0	$0.1
Interdepartmental	0	29,216	10.40	0	13,795	21.62	$0.0	$0.3	($0.3)
Ultimate Consumer	$ 14	6,431,254	$ 2.20	$ 16	7,014,569	$ 2.26	($1.7)	($1.4)	($0.2)

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 22	7,534,530	$ 2.87	$ 24	8,239,404	$ 2.87	($2)	$ (2)	$ (0)
Commercial	7	3,257,096	2.15	7	3,338,981	2.15	($0)	$ (0)	$ 0
Industrial	1	283,044	2.25	1	359,241	2.18	($0)	$ (0)	$ 0
Public Authority	1	473,784	2.12	1	512,212	2.13	($0)	$ (0)	$ (0)
Transportation	2	2,968,101	0.52	1	2,831,939	0.47	$0	$0	$0
Interdepartmental	1	57,386	10.58	1	26,517	22.48	$0	$1	($1)
Ultimate Consumer	$ 32	14,573,941	$ 2.22	$ 35	15,308,295	$ 2.26	($2)	($2)	($1)

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($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	$ 14	$ 16	$ 2	0	0	1	1	(0)
Project Engineering	0	0	(0)	0	-	-	(0)	(0)
Transmission	2	2	(0)	(0)	(0)	(0)	(0)	0
Energy Supply and Analysis	1	1	(0)	(0)	-	0	(0)	(0)
Generation Services	1	1	(0)	0	0	(0)	(0)	(0)
Electric Distribution	5	5	0	(0)	0	(0)	(0)	0
Gas Distribution	3	3	(0)	(0)	(0)	(0)	0	(0)
Safety and Security	0	0	(0)	(0)	(0)	0	(0)	(0)
Customer Services	7	7	(0)	(0)	(0)	(0)	0	(0)
Chief Operations Officer	**35**	**36**	**1**	**0**	**0**	**0**	**1**	**(0)**
General Counsel	3	3	0	0	0	(0)	0	0
Human Resources	1	1	0	(0)	-	0	0	0
General Counsel & HR	**3**	**4**	**0**	**0**	**0**	**(0)**	**0**	**0**
Audit Services	0	0	0	0	-	(0)	0	0
Controller	1	1	(0)	(0)	-	0	0	(0)
Information Technology	5	5	0	0	(0)	0	0	0
Supply Chain	0	0	0	(0)	-	0	(0)	0
Treasurer	1	1	0	(0)	-	(0)	(0)	0
Chief Financial Officer	**7**	**7**	**0**	**(0)**	**(0)**	**0**	**0**	**0**
Corporate	**14**	**14**	**(0)**	**(1)**	**(0)**	**0**	**(0)**	**0**
O&M Total MTD	**$ 59**	**$ 60**	**$ 1**	**(0)**	**(0)**	**1**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	$ 27	$ 30	$ 2	$ 1	$ 0	$ 1	$ 1	$ (1)
Project Engineering	0	0	(0)	0	0	(0)	(0)	(0)
Transmission	5	4	(0)	(0)	0	(0)	(0)	0
Energy Supply and Analysis	2	2	0	(0)	0	0	0	0
Generation Services	2	2	(0)	0	0	(0)	(0)	(0)
Electric Distribution	11	11	0	(0)	1	(0)	(0)	0
Gas Distribution	5	5	(0)	(0)	0	(0)	0	(0)
Safety and Security	1	1	(0)	(0)	(0)	0	(0)	(0)
Customer Services	14	14	(0)	(0)	0	(0)	(0)	(0)
Chief Operations Officer	**67**	**69**	**2**	**0**	**1**	**0**	**1**	**(1)**
General Counsel	5	6	1	0	0	(0)	0	0
Human Resources	1	1	(0)	(0)	0	0	(0)	0
General Counsel & HR	**6**	**7**	**0**	**0**	**0**	**(0)**	**0**	**0**
Audit Services	0	0	0	0	0	0	0	0
Controller	2	2	(0)	(0)	0	0	0	0
Information Technology	9	10	0	0	0	0	0	0
Supply Chain	1	1	(0)	(0)	0	0	0	0
Treasurer	2	2	0	(0)	0	(0)	(0)	0
Chief Financial Officer	**13**	**14**	**1**	**(0)**	**0**	**0**	**0**	**1**
Corporate	**25**	**26**	**1**	**0**	**(0)**	**0**	**(0)**	**1**
O&M Total YTD	**$ 112**	**$ 116**	**$ 4**	**$ 0**	**$ 1**	**$ 1**	**$ 2**	**$ 1**

Note: Schedules may not sum due to rounding.

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Financing Activities — February 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 923.9	$ 923.9	$ (0.0)
End Bal	923.9	923.9	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ (0.0)**
Interest Exp	**$ 1.9**	**$ 2.3**	**$ 0.4**
Rate	**1.24%**	**1.50%**	**0.27%**
FMB/Sr Nts			
Beg Bal	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 30.0**	**$ 29.2**	**$ (0.8)**
Rate	**4.28%**	**4.16%**	**-0.11%**
Short-term Debt			
Beg Bal	$ 318.9	$ 288.5	$ (30.4)
End Bal	290.9	231.9	(59.0)
Ave Bal	**$ 304.9**	**$ 260.2**	**$ (44.7)**
Interest Exp	**$ 0.6**	**$ 0.9**	**$ 0.3**
Rate	**1.26%**	**2.06%**	**0.79%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (46.3)	$ (45.6)	$ 0.7
End Bal	(45.7)	(44.9)	0.8
Ave Bal	**$ (46.0)**	**$ (45.2)**	**$ 0.8**
Total End Bal	**$ 5,379.1**	**$ 5,320.9**	**$ (58.2)**
Total Average Bal	**$ 5,392.8**	**$ 5,348.8**	**$ (44.0)**
Total Expense Excl I/C (1)	**$ 35.1**	**$ 36.3**	**$ 1.2**
Rate	**3.87%**	**4.03%**	**0.16%**

(1) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(2)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 134		$ 166
LG&E	500	141		359
KU	598	16	$ 198	384
TOTAL	$ 1,398	$ 291	$ 198	$ 909

(2) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	18%	18%	26%	28%	25%	25%
CFO pre-WC + Interest / Interest	6.0	6.0	8.8	9.1	7.8	7.7
CFO pre-WC - Dividends / Debt	15%	16%	25%	27%	18%	18%
Debt to Capitalization[2]	48%	48%	40%	39%	39%	39%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

(1) Actuals represent a trailing 12 months.

(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — February 2016

($ Millions)

	2/29/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 25	$ 36	$ (11)	Lower cash balance offset by lower debt balance – see below.
Accounts Receivable (Trade)	438	403	36	
Inventory	276	255	20	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	20	49	(29)	Decrease primarily due to lower balances related to FAC and ECR.
Prepayments and other current assets	32	39	(6)	
Total Current Assets	791	781	10	
Property, Plant, and Equipment	11,420	11,462	(42)	
Intangible Assets	119	115	4	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	745	731	14	
Goodwill	997	997	-	
Other Long-term Assets	77	76	1	
Total Assets	**$ 14,150**	**$ 14,164**	**$ (14)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 230	$ 276	$ (46)	Primarily related to decreases in project engineering accruals and other timing of payables.
Dividends Payable to Affiliated Companies	29	-	29	
Customer Deposits	53	52	1	
Derivative Liability	6	5	1	
Accrued Taxes	86	112	(27)	Primarily related to timing of property tax payments budgeted in Q4 2015.
Regulatory Liabilities Current	26	32	(5)	
Other Current Liabilities	232	247	(16)	
Total Current Liabilities	662	725	(62)	
Debt - Affiliated Company	459	470	(11)	
Debt [(1)]	4,920	4,851	69	
Total Debt	5,379	5,321	58	
Deferred Tax Liabilities	1,463	1,463	(0)	
Investment Tax Credit	127	127	0	
Accum Provision for Pension & Related Benefits	270	266	3	
Asset Retirement Obligation	488	489	(0)	
Regulatory Liabilities Non Current	919	914	5	
Derivative Liability	49	42	7	
Other Liabilities	208	207	2	
Total Deferred Credits and Other Liabilities	3,524	3,508	16	
Equity	4,584	4,610	(26)	
Total Liabilities and Equity	**$ 14,150**	**$ 14,164**	**$ (14)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

February 2016

($ Millions)

	2/29/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 5	$ 8	
Accounts Receivable (Trade)	191	181	10	
Inventory	122	105	17	Primarily due to increased coal purchases.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	10	15	(5)	
Prepayments and other current assets	30	33	(3)	
Total Current Assets	366	339	27	
Property, Plant, and Equipment	4,807	4,845	(37)	
Intangible Assets	6	4	2	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	432	421	11	
Goodwill	-	-	-	
Other Long-term Assets	18	18	1	
Total Assets	**$ 5,630**	**$ 5,627**	**$ 3**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 149	$ 185	$ (36)	Primarily related to decreases in project engineering accruals, retention balances and other timing of payables.
Dividends Payable to Affiliated Companies	25	25	(0)	
Customer Deposits	26	25	0	
Derivative Liability	6	5	1	
Accrued Taxes	31	51	(20)	Primarily related to timing of property tax payments budgeted in Q4 2015.
Regulatory Liabilities Current	9	13	(4)	
Other Current Liabilities	81	85	(5)	
Total Current Liabilities	326	390	(64)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,782	1,728	54	
Total Debt	1,782	1,728	54	
Deferred Tax Liabilities	828	829	(0)	
Investment Tax Credit	34	34	(0)	
Accum Provision for Pension & Related Benefits	45	43	2	
Asset Retirement Obligation	150	150	(0)	
Regulatory Liabilities Non Current	365	363	2	
Derivative Liability	49	42	7	
Other Liabilities	93	91	1	
Total Deferred Credits and Other Liabilities	1,564	1,552	12	
Equity	1,958	1,956	2	
Total Liabilities and Equity	**$ 5,630**	**$ 5,627**	**$ 3**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU — February 2016

($ Millions)

	2/29/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 12	$ 27	$ (15)	Budget had additional available cash after paying off short term debt needs (see debt variance below).
Accounts Receivable (Trade)	247	221	26	Higher customer accounts receivable of $12m and accrued utility revenue of $16m.
Inventory	153	150	3	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	10	34	(24)	Decrease primarily due to lower balances related to FAC and ECR.
Prepayments and other current assets	10	17	(7)	
Total Current Assets	432	448	(16)	
Property, Plant, and Equipment	6,605	6,610	(5)	
Intangible Assets	13	11	2	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	308	305	3	
Goodwill	-	-	-	
Other Long-term Assets	50	49	0	
Total Assets	**$ 7,408**	**$ 7,424**	**$ (16)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 116	$ 131	$ (15)	Primarily related to decreases in project engineering accruals and other timing of payables.
Dividends Payable to Affiliated Companies	64	29	35	Larger dividend declared to maintain balanced capital structure.
Customer Deposits	27	26	1	
Derivative Liability	-	-	-	
Accrued Taxes	51	61	(10)	Primarily related to timing of property tax payments budgeted in Q4 2015.
Regulatory Liabilities Current	17	18	(1)	
Other Current Liabilities	89	100	(11)	Primarily related to reduction in the amount of outstanding checks. This activity is not budgeted.
Total Current Liabilities	364	365	(1)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,339	2,323	16	
Total Debt	2,339	2,323	16	
Deferred Tax Liabilities	1,047	1,047	(0)	
Investment Tax Credit	93	93	0	
Accum Provision for Pension & Related Benefits	38	37	1	
Asset Retirement Obligation	338	338	(0)	
Regulatory Liabilities Non Current	454	452	3	
Derivative Liability	-	-	-	
Other Liabilities	60	60	0	
Total Deferred Credits and Other Liabilities	2,030	2,027	3	
Equity	2,675	2,709	(34)	
Total Liabilities and Equity	**$ 7,408**	**$ 7,424**	**$ (16)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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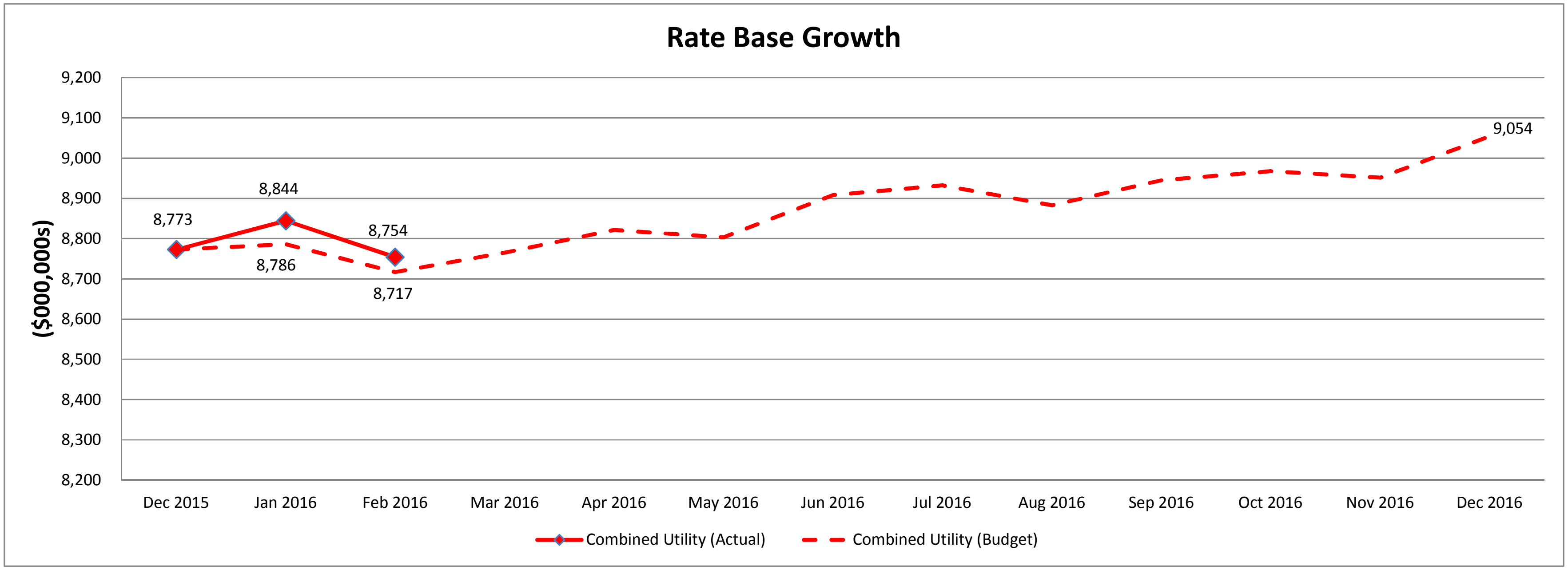

Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,773
8,844
8,754
8,786
8,717
9,054
Dec 2015
Jan 2016
Feb 2016
Mar 2016
Apr 2016
May 2016
Jun 2016
Jul 2016
Aug 2016
Sep 2016
Oct 2016
Nov 2016
Dec 2016
Combined Utility (Actual)
Combined Utility (Budget)

Performance Report

March 2016

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Kentucky Regulated Dashboard

March 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.47	1.07	0.91	1.26	1.38	1.22
Employee lost-time incidents	1	0	1	0	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,518	2,796	8,464	9,045	34,382	34,964
Utility EFOR	9.0%	5.7%	4.7%	5.7%	N/A	5.7%
Utility EAF	75.9%	86.1%	87.2%	86.1%	N/A	82.3%
Steam Fleet Commercial Availability	95.3%	92.8%	97.5%	92.8%	N/A	92.8%
Combined SAIFI	0.08	0.06	0.19	0.20	N/A	1.03
Combined SAIDI (minutes)	6.65	5.58	17.69	18.77	N/A	94.09
GwH Sales						
Residential	717	893	2,872	3,043	10,676	10,847
Commercial	591	606	1,880	1,874	7,799	7,793
Industrial	767	792	2,264	2,365	9,988	10,089
Municipals	141	152	470	481	1,875	1,886
Other	219	220	673	680	2,791	2,798
Off-System Sales	3	35	36	241	108	322
Total	2,438	2,698	8,195	8,684	33,237	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.71%			
Commercial			0.28%			
Industrial			-2.84%			
Municipal			0.76%			
Other			0.56%			
Total			-1.57%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	7.4%	8.9%	11.4%	11.6%	9.8%	9.8%
Electric Margins	$140	$149	$462	$471	$1,861	$1,870
Gas Margins	16	18	62	66	172	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$2	$1	$10	$6	$16	$9
ECR	24	36	48	95	370	404
Generation	9	12	19	25	127	117
Transmission	6	7	15	19	91	90
Electric Distribution	14	13	35	35	172	169
Gas Distribution	6	6	16	18	88	86
Customer Services	2	2	4	5	20	20
IT and Other	6	5	15	13	61	59
Total	$68	$81	$161	$216	$947	$955
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$40	$42	$106	$111	$458	$459
General Counsel & HR	4	4	11	11	42	42
Finance, IT, & Supply Chain	8	8	22	22	101	86
Burdens & Other Charges	14	12	39	38	128	144
Total	$66	$66	$178	$182	$729	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,467	3,571	3,467	3,571	3,600	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	0	7	N/A	16
NERC Possible Violations[4]	0	0	0	1	N/A	8

Variance Explanations

• Current month higher EFOR primarily due to main transformer failure and fire at Mill Creek.

• Current month lower margins primarily due to warmer than normal weather resulting in $10 million lower retail electric base energy and demand revenue and $2 million lower gas margins. March 2016 ranked as the 3rd warmest compared to the previous 30 years.

• YTD lower margins primarily due to warmer than normal weather during the month of March, resulting in lower YTD retail electric base energy and demand revenue of $12 million and $4 million lower gas margins. This was partially offset by $2 million lower cost of production.

• Current month and YTD capital expenditures were lower, primarily due to the timing of Environmental Cost Recovery (ECR) spending on Environmental Air projects at Mill Creek and Ghent.

Major Developments

• Mill Creek Unit 3 recently began its scheduled maintenance outage which includes the facilitation of the tie-in of its baghouse project. This marks the tenth and final baghouse in the MATS compliance program and the conclusion of the 2011 ECR Plans, which also included the completion of the Brown Phase 1 Landfill.

• LKE recently experienced a significant wind event with speeds between 35-60 mph over eight hours. 30,000 customers were affected with almost all customers restored within 24 hours. LKE also provided 57 contract resources to Duke Midwest and AEP-Virginia to assist in their restoration efforts.

Significant Future Events

• Construction of the Brown Solar project is progressing and the facility is expected to be commercially operational by late spring.

• Regarding the $1.0 billion ECR plan proceedings, intervenor testimony will be filed in May, and a formal hearing is expected in June.

(1) Full year forecast amount shown represents target.

(2) Excludes goodwill and other purchase accounting adjustments.

(3) Net of cost recovery mechanisms.

(4) The possible violation issues are believed to be minimal risk.

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Income Statement: Actual vs. Budget (Month) — March 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 211	$ 240	$ (29)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	27	37	(10)	See Gas Supply Expenses explanation below.
Total Revenues	238	277	(39)	
Cost of Sales:				
Fuel Electric Costs	56	72	17	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	11	19	8	Due to lower net purchases and lower gas prices.
Purchased Power	4	4	0	
Other Electric Cost	12	14	2	
Total Cost of Sales	83	110	27	
Gross Margin:				
Electric Margin	140	149	(10)	Lower margins primarily due to warmer than normal weather resulting in $10 million lower retail electric base energy and demand revenue. March 2016 ranked as the 3rd warmest compared to the previous 30 years.
Gas Margin	16	18	(2)	
Total Gross Margin	156	167	(11)	
Operating Expenses:				
O&M	66	66	(1)	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	100	100	0	
Other income (expense)	(1)	(1)	0	
EBIT	55	66	(11)	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	37	48	(11)	
Income Tax Expense	13	18	5	Lower income taxes primarily due to lower pre-tax income.
Net Income (loss) from ongoing operations	**24**	**30**	**$ (6)**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 24	$ 30	$ (6)	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 22	$ 28	$ (6)	
Earnings Per Share - Ongoing	$ 0.03	$ 0.04	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

March 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 709	$ 761	$ (51)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	117	142	(25)	See Gas Supply Expenses explanation below.
Total Revenues	827	903	(76)	
Cost of Sales:				
Fuel Electric Costs	198	234	36	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	55	76	21	Due to lower net purchases and lower gas prices.
Purchased Power	13	13	0	
Other Electric Cost	35	42	7	Due to lower ECR expense and scrubber reactant expense.
Total Cost of Sales	302	366	64	
Gross Margin:				
Electric Margin	462	471	(9)	Lower margins primarily due to warmer than normal weather during the month of March, resulting in lower YTD retail electric base energy and demand revenue of $12 million. This was partially offset by $2 million lower cost of production.
Gas Margin	62	66	(4)	
Total Gross Margin	524	537	(13)	
Operating Expenses:				
O&M	178	181	3	
Depreciation & Amortization	87	89	2	
Taxes, Other than Income	14	14	0	
Total Operating Expenses	278	284	6	
Other income (expense)	(3)	(3)	(0)	
EBIT	243	250	(7)	
Interest Expense	53	54	2	
Income from Ongoing Operations before income taxes	190	196	(6)	
Income Tax Expense	72	75	3	
Net Income (loss) from ongoing operations	**119**	**121**	**$ (2)**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 119	$ 121	$ (2)	
KY Regulated Financing Costs	(8)	$ (7)	(0)	
KY Regulated Net Income	$ 111	$ 113	$ (2)	
Earnings Per Share - Ongoing	$ 0.16	$ 0.17	$ (0.00)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E

March 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 270	$ 281	$ (11)	Primarily due to lower off system sales which were offset by lower related fuel costs below.
Gas Revenues	117	142	(25)	See Gas Supply Expenses explanation below.
Total Revenues	387	423	(36)	
Cost of Sales:				
Fuel Electric Costs	79	89	10	Primarily due to lower offsystem related fuel costs.
Gas Supply Expenses	55	76	21	Due to lower net purchases and lower gas prices.
Purchased Power	11	11	0	
Other Electric Cost	13	16	3	
Total Cost of Sales	159	193	35	
Gross Margin:				
Electric Margin	167	164	2	
Gas Margin	62	66	(4)	
Total Gross Margin	229	230	(1)	
Operating Expenses:				
O&M	77	79	1	
Depreciation & Amortization	35	36	1	
Taxes, Other than Income	7	7	0	
Total Operating Expenses	119	122	3	
Other income (expense)	(2)	(1)	(0)	
EBIT	108	107	1	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	90	89	1	
Income Tax Expense	35	34	(0)	
Net Income (loss) from ongoing operations	**56**	**55**	**$ 1**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

March 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 453	$ 500	$ (47)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	-	-	-	
Total Revenues	453	500	(47)	
Cost of Sales:				
Fuel Electric Costs	120	148	28	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	-	-	-	
Purchased Power	15	19	4	
Other Electric Cost	22	26	4	
Total Cost of Sales	157	193	36	
Gross Margin:				
Electric Margin	296	307	(11)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	296	307	(11)	
Operating Expenses:				
O&M	92	95	3	
Depreciation & Amortization	51	53	1	
Taxes, Other than Income	7	7	0	
Total Operating Expenses	150	155	4	
Other income (expense)	(1)	(1)	0	
EBIT	144	151	(7)	
Interest Expense	24	24	1	
Income from Ongoing Operations before income taxes	121	127	(6)	
Income Tax Expense	46	48	2	
Net Income (loss) from ongoing operations	**75**	**78**	**$ (3)**	

Note: Schedules may not sum due to rounding.

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Income Statement: Forecast vs. Budget — March 2016

($ Millions)

	Full Year			
	Q1 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,952	$ 3,011	$ (59)	Due to lower volumes driven by unfavorable weather, along with lower fuel costs as shown below.
Gas Revenues	307	330	(24)	See Gas Supply Expenses explanation below.
Total Revenues	3,259	3,342	(83)	
Cost of Sales:				
Fuel Electric Costs	865	901	36	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	135	155	20	Due to lower net purchases and lower gas prices.
Purchased Power	57	58	0	
Other Electric Cost	171	182	11	Due to lower ECR expense and scrubber reactant expense.
Total Cost of Sales	1,229	1,296	68	
Gross Margin:				
Electric Margin	1,858	1,870	(12)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	172	175	(4)	
Total Gross Margin	2,030	2,045	(15)	
Operating Expenses:				
O&M	729	731	2	
Depreciation & Amortization	351	359	7	Due to increased auto-retirements not captured in the budget, along with revised in-service dates and final spend on completed projects.
Taxes, Other than Income	56	56	1	
Total Operating Expenses	1,136	1,146	10	
Other income (expense)	(7)	(7)	(0)	
EBIT	886	892	(6)	
Interest Expense	214	217	3	
Income from Ongoing Operations before income taxes	672	675	(3)	
Income Tax Expense	255	257	3	
Net Income (loss) from ongoing operations	**417**	**417**	**$ (0)**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 417	$ 417	$ 0	
KY Regulated Financing Costs	(30)	$ (30)	-	
KY Regulated Net Income	$ 387	$ 387	$ 0	
Earnings Per Share - Ongoing	$ 0.57	$ 0.57	$ (0.00)	

Note: Schedules may not sum due to rounding.

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Electric Gross Margin Analysis - MTD ($ Millions) March 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	70	80	(10)
Demand	42	43	(0)
Base Service Charge	14	14	(0)
Rate Mechanisms	16	16	0
Other Rev/Cost of Sales	0	(1)	1
Other Margin Items	(2)	(2)	(0)
	140	149	(10)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	27	29	(2)
Demand	14	13	1
Base Service Charge	6	6	(0)
Rate Mechanisms	9	8	1
Other Rev/Cost of Sales	0	(0)	0
Other Margin Items	(2)	(2)	0
	54	53	0

KU Electric Margin

	Actual	Budget	Variance
Base Energy	42	51	(8)
Demand	28	30	(1)
Base Service Charge	8	8	(0)
Rate Mechanisms	7	8	(1)
Other Rev/Cost of Sales	0	(1)	1
Other Margin Items	(0)	(0)	(0)
	86	96	(10)

LKE Base Energy Price/Vol Variance

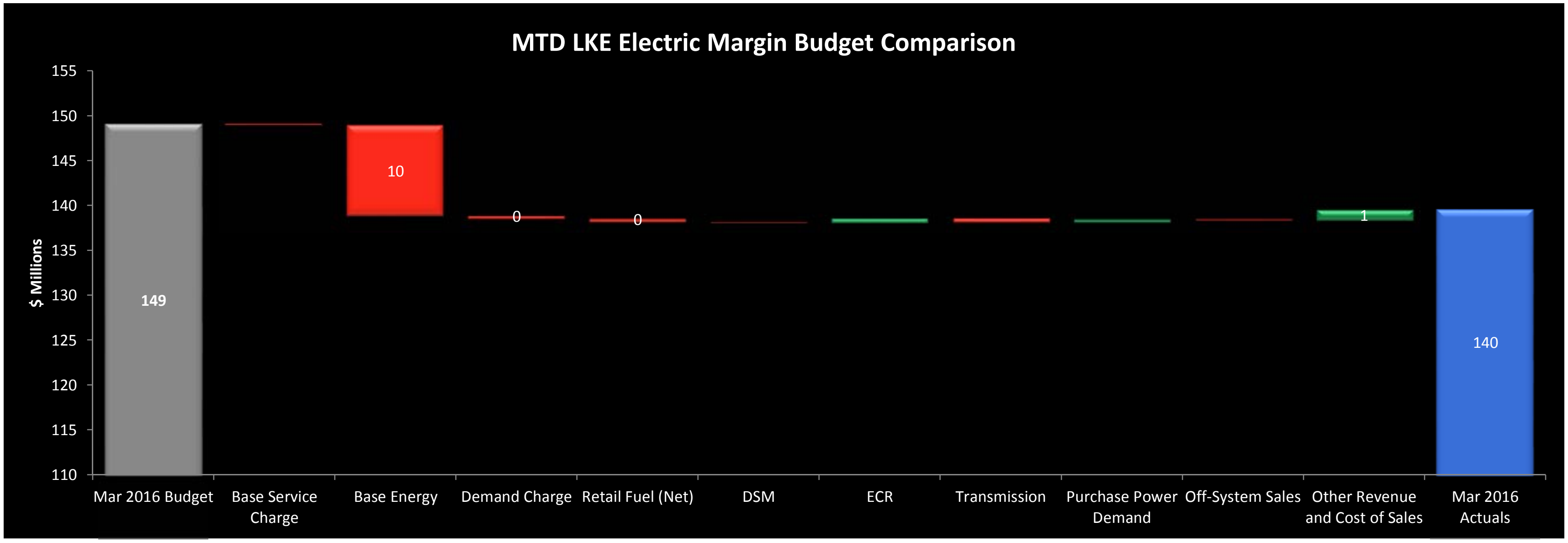
	Volume	Price	Total Variance
Residential	(9)	1	(9)
Commercial	(1)	(1)	(1)
Industrial	(0)	0	0
Public Authority	(0)	0	0
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	(10)	0	(10)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(2)	0	(2)
Commercial	0	(0)	(0)
Industrial	0	0	0
Public Authority	0	0	0
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(2)	0	(2)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(7)	0	(7)
Commercial	(1)	(0)	(1)
Industrial	(0)	0	(0)
Public Authority	(0)	0	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	(8)	0	(8)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Electric Gross Margin Analysis - YTD

($ Millions)

March 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	250	260	(10)
Demand	129	131	(2)
Base Service Charge	41	41	(0)
Rate Mechanisms	46	45	1
Other Rev/Cost of Sales	(0)	(3)	2
Other Margin Items	(4)	(4)	0
	462	471	(9)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	89	90	(1)
Demand	42	41	1
Base Service Charge	17	17	(0)
Rate Mechanisms	23	22	1
Other Rev/Cost of Sales	0	(1)	1
Other Margin Items	(4)	(5)	0
	167	164	2

KU Electric Margin

	Actual	Budget	Variance
Base Energy	161	170	(9)
Demand	87	90	(3)
Base Service Charge	24	24	0
Rate Mechanisms	23	24	(0)
Other Rev/Cost of Sales	(0)	(2)	1
Other Margin Items	1	1	(0)
	296	307	(11)

LKE Base Energy Price/Vol Variance

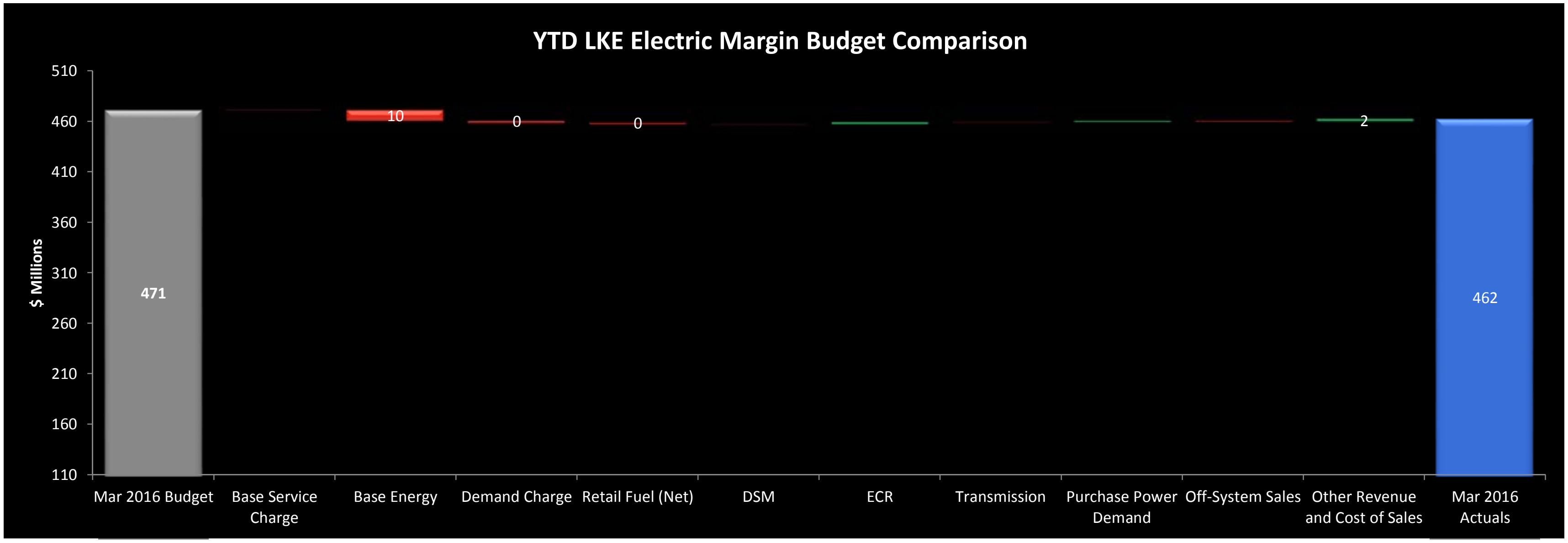
	Volume	Price	Total Variance
Residential	(9)	2	(8)
Commercial	0	(2)	(2)
Industrial	(1)	0	(0)
Public Authority	(0)	0	0
Street Lights	(0)	0	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(10)	0	(10)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(2)	1	(2)
Commercial	1	(1)	0
Industrial	(0)	0	(0)
Public Authority	0	0	1
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(2)	1	(1)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(7)	1	(6)
Commercial	(1)	(1)	(2)
Industrial	(0)	0	(0)
Public Authority	(0)	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(9)	(1)	(9)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin — March 2016

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**0**	**$ 16**	**$ 16**		**0**
Gas Supply Costs								
Gas Supply Costs	(10)	(18)	$ 8		(53)	(73)	$ 21	
GSC Revenue	10	18	$ (8)		53	73	$ (20)	
Net Gas Supply Costs				**0**				**0**
Retail Gas (a)	**8**	**11**		**(4)**	**40**	**46**		**(6)**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**-**
DSM	**0**	**0**		**(0)**	**0**	**0**		**(0)**
GLT	**1**	**1**		**0**	**3**	**3**		**0**
WNA	**1**	**-**		**1**	**2**	**-**		**2**
Other Margin	**0**	**0**		**0**	**1**	**0**		**0**
Gas Margin Variance				**$ (2)**				**$ (4)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 5	1,615,463	$ 2.87	$ 8	2,671,224	$ 2.87	($3.0)	($3.0)	($0.0)
Commercial	2	773,789	2.15	2	1,095,630	2.15	($0.7)	($0.7)	$0.0
Industrial	0	97,243	2.25	0	134,623	2.17	($0.1)	($0.1)	$0.0
Public Authority	0	121,322	2.16	0	170,247	2.12	($0.1)	($0.1)	$0.0
Transportation	1	1,210,591	0.54	1	1,085,012	0.47	$0.2	$0.1	$0.1
Interdepartmental	0	49,615	6.29	0	14,829	20.14	$0.0	$0.7	($0.7)
Ultimate Consumer	$ 8	3,868,023	$ 2.00	$ 11	5,171,566	$ 2.22	($3.7)	($3.1)	($0.6)

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 26	9,149,993	$ 2.87	$ 31	10,910,629	$ 2.87	($5)	$ (5)	$ (0)
Commercial	9	4,030,885	2.15	10	4,434,611	2.15	($1)	$ (1)	$ 0
Industrial	1	380,287	2.25	1	493,865	2.18	($0)	$ (0)	$ 0
Public Authority	1	595,106	2.13	1	682,460	2.13	($0)	$ (0)	$ (0)
Transportation	2	4,178,692	0.53	2	3,916,951	0.47	$0	$0	$0
Interdepartmental	1	107,001	8.59	1	41,346	21.64	$0	$1	($1)
Ultimate Consumer	$ 40	18,441,964	$ 2.18	$ 46	20,479,861	$ 2.25	($6)	($5)	($1)

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	20	21	1	0	(0)	1	1	(1)
Project Engineering	0	0	0	0	-	-	(0)	0
Transmission	2	2	0	0	0	0	(0)	0
Energy Supply and Analysis	1	1	0	0	-	0	0	0
Generation Services	1	1	0	0	0	(1)	(0)	1
Electric Distribution	5	6	1	0	1	(0)	0	0
Gas Distribution	3	3	(0)	0	(0)	(0)	(0)	(0)
Safety and Security	0	1	0	0	(0)	0	0	0
Customer Services	7	7	0	0	(0)	0	0	0
Chief Operations Officer	**40**	**42**	**2**	**1**	**(0)**	**(1)**	**1**	**1**
General Counsel	4	3	(0)	0	0	(0)	(0)	0
Human Resources	1	1	0	(0)	-	0	0	0
General Counsel & HR	**4**	**4**	**(0)**	**0**	**0**	**(0)**	**(0)**	**0**
Audit Services	0	0	(0)	(0)	-	(0)	0	0
Controller	1	1	0	0	-	(0)	(0)	0
Information Technology	5	5	0	0	(0)	0	(0)	0
Supply Chain	0	0	0	0	(0)	0	0	(0)
Treasurer	2	1	(1)	(0)	-	(0)	0	(1)
Chief Financial Officer	**8**	**8**	**(1)**	**0**	**(0)**	**(0)**	**(0)**	**(1)**
Corporate	**14**	**12**	**(2)**	**(2)**	**(0)**	**0**	**(0)**	**0**
O&M Total MTD	**66**	**66**	**(1)**	**(1)**	**(0)**	**(1)**	**1**	**0**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	47	50	3	1	(0)	2	3	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	7	7	(0)	(0)	0	(0)	(0)	0
Energy Supply and Analysis	2	2	0	0	-	0	0	0
Generation Services	3	3	0	0	0	(1)	(0)	1
Electric Distribution	16	17	1	(0)	1	(0)	(0)	0
Gas Distribution	8	8	(0)	0	(0)	(0)	(0)	(0)
Safety and Security	1	1	0	0	(0)	0	0	(0)
Customer Services	21	21	0	0	0	(0)	0	(0)
Chief Operations Officer	**106**	**111**	**5**	**1**	**1**	**(0)**	**3**	**0**
General Counsel	9	9	0	0	0	(1)	0	0
Human Resources	2	2	0	(0)	-	0	(0)	0
General Counsel & HR	**11**	**11**	**0**	**0**	**0**	**(1)**	**0**	**0**
Audit Services	0	0	0	0	-	(0)	0	0
Controller	2	2	0	(0)	-	0	(0)	0
Information Technology	14	15	1	0	(0)	0	0	0
Supply Chain	1	1	(0)	(0)	(0)	0	0	0
Treasurer	4	3	(1)	(0)	-	(0)	(0)	(1)
Chief Financial Officer	**22**	**22**	**(0)**	**0**	**(0)**	**0**	**0**	**(0)**
Corporate	**39**	**38**	**(1)**	**(2)**	**(1)**	**1**	**(0)**	**1**
O&M Total YTD	**178**	**182**	**4**	**(0)**	**1**	**0**	**3**	**1**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	205	206	0	(1)	1	(1)	0	1
Project Engineering	1	1	0	0	-	0	0	(0)
Transmission	30	30	(0)	0	0	0	0	(0)
Energy Supply and Analysis	9	9	0	(0)	-	0	(0)	(0)
Generation Services	16	15	(0)	0	(0)	1	0	(1)
Electric Distribution	72	73	1	(0)	4	(4)	(0)	(0)
Gas Distribution	34	34	0	0	(0)	0	(0)	0
Safety and Security	5	5	(0)	0	0	0	(0)	0
Customer Services	86	87	0	(0)	0	(0)	(0)	0
Chief Operations Officer	**458**	**459**	**1**	**(2)**	**5**	**(3)**	**(0)**	**(1)**
General Counsel	35	35	0	(0)	0	(0)	(0)	0
Human Resources	7	7	0	(0)	-	(0)	(0)	(0)
General Counsel & HR	**42**	**42**	**0**	**(0)**	**0**	**(0)**	**(0)**	**(0)**
Audit Services	2	2	0	(0)	-	0	(0)	0
Controller	10	10	(0)	0	-	(0)	0	(0)
Information Technology	60	60	0	(0)	1	(0)	(0)	0
Supply Chain	4	4	(0)	0	0	(0)	0	0
Treasurer	25	11	(14)	0	-	0	0	14
Chief Financial Officer	**100**	**86**	**(14)**	**1**	**1**	**(0)**	**(0)**	**14**
Corporate	**128**	**144**	**15**	**0**	**0**	**(0)**	**0**	**(16)**
O&M Total Full Year	**729**	**731**	**2**	**(1)**	**6**	**(4)**	**(0)**	**(3)**

Note: Schedules may not sum due to rounding.

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Financing Activities — March 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.9	$ (0.0)	$ 923.9	$ 923.9	$ -
End Bal	923.8	923.9	0.0	923.8	923.8	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ 0.0**	**$ 923.8**	**$ 923.8**	**$ (0.0)**
Interest Exp	**$ 2.9**	**$ 3.5**	**$ 0.6**	**$ 13.3**	**$ 13.9**	**$ 0.6**
Rate	**1.25%**	**1.49%**	**0.24%**	**1.42%**	**1.48%**	**0.06%**
FMB/Sr Nts						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 45.0**	**$ 43.8**	**$ (1.2)**	**$ 173.0**	**$ 175.3**	**$ 2.3**
Rate	**4.23%**	**4.12%**	**-0.11%**	**4.04%**	**4.10%**	**0.05%**
Short-term Debt						
Beg Bal	$ 318.9	$ 231.9	$ (87.0)	$ 318.9	$ 318.9	$ -
End Bal	262.5	215.2	(47.3)	451.8	347.7	(104.1)
Ave Bal	**$ 290.7**	**$ 223.6**	**$ (67.2)**	**$ 385.4**	**$ 333.3**	**$ (52.1)**
Interest Exp	**$ 1.0**	**$ 1.3**	**$ 0.3**	**$ 8.5**	**$ 4.8**	**$ (3.7)**
Rate	**1.33%**	**2.23%**	**0.90%**	**2.16%**	**1.40%**	**-0.76%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (44.9)	$ 1.5	$ (46.3)	$ (46.3)	$ -
End Bal	(45.4)	(44.2)	1.2	(42.2)	(39.6)	2.6
Ave Bal	**$ (45.9)**	**$ (44.5)**	**$ 1.3**	**$ (44.3)**	**$ (43.0)**	**$ 1.3**
Total End Bal	**$ 5,351.0**	**$ 5,304.9**	**$ (46.1)**	**$ 5,543.4**	**$ 5,441.9**	**$ (101.5)**
Total Average Bal	**$ 5,378.7**	**$ 5,312.9**	**$ (65.8)**	**$ 5,474.9**	**$ 5,424.2**	**$ (50.8)**
Total Expense Excl I/C [1]	**$ 52.7**	**$ 54.3**	**$ 1.6**	**$ 214.4**	**$ 217.2**	**$ 2.8**
Rate	**3.84%**	**4.01%**	**0.17%**	**3.82%**	**3.91%**	**0.09%**

[1] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[2]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 147		$ 153
LG&E	500	82		418
KU	598	34	$ 198	366
TOTAL	$ 1,398	$ 263	$ 198	$ 937

[2] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	 Budget YTD	LG&E 2016 Actual YTD	 Budget YTD	KU 2016 Actual YTD	 Budget YTD
CFO pre-WC / Debt	17%	18%	27%	27%	24%	24%
CFO pre-WC + Interest / Interest	5.6	5.8	8.4	8.7	7.5	7.5
CFO pre-WC - Dividends / Debt	15%	15%	27%	26%	16%	16%
Debt to Capitalization[2]	47%	47%	38%	39%	39%	39%

Credit Metrics Moody's	LKE 2016 BP 2017	 2018	LG&E 2016 BP 2017	 2018	KU 2016 BP 2017	 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015 Issuer	Senior Unsecured Moody's	Senior Secured Moody's	Commercial Paper Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

March 2016

($ Millions)

	3/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 28	$ 14	$ 14	Budget included increased payments related to Accounts Payable and Capital Expenditures.
Accounts Receivable (Trade)	368	384	(16)	
Inventory	277	245	32	Higher actual due to lower than expected usage and higher than budgeted purchases.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	17	53	(36)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	36	37	(1)	
Total Current Assets	726	733	(7)	
Property, Plant, and Equipment	11,449	11,501	(52)	
Intangible Assets	117	113	4	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	744	733	11	
Goodwill	997	997	-	
Other Long-term Assets	76	77	(1)	
Total Assets	**$ 14,111**	**$ 14,156**	**$ (45)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 241	$ 272	$ (31)	Primarily related to decreases in power generation accruals, retention balances and other timing of payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	53	52	2	
Derivative Liability	6	5	1	
Accrued Taxes	21	85	(64)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	30	31	(1)	
Other Current Liabilities	234	207	27	Increase primarily due to reclassification of ARO liability from non-current to current liabilities and timing of interest payments. The increase is partially offset by a reduction in the amount of outstanding checks. This activity is not budgeted.
Total Current Liabilities	586	653	(66)	
Debt - Affiliated Company	547	400	147	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016.
Debt [(1)]	4,804	4,905	(100)	
Total Debt	5,351	5,305	46	
Deferred Tax Liabilities	1,532	1,522	10	
Investment Tax Credit	127	127	0	
Accum Provision for Pension & Related Benefits	267	267	(0)	
Asset Retirement Obligation	470	491	(21)	
Regulatory Liabilities Non Current	917	907	10	
Derivative Liability	47	42	5	
Other Liabilities	205	204	1	
Total Deferred Credits and Other Liabilities	3,565	3,560	5	
Equity	4,609	4,638	(30)	
Total Liabilities and Equity	**$ 14,111**	**$ 14,156**	**$ (45)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E — March 2016

($ Millions)

	3/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 11	$ 5	$ 6	
Accounts Receivable (Trade)	159	169	(10)	
Inventory	120	95	25	Higher actual due to lower than expected usage and higher than budgeted purchases.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	7	18	(10)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	32	33	(0)	
Total Current Assets	329	319	10	
Property, Plant, and Equipment	4,828	4,874	(46)	
Intangible Assets	6	4	2	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	428	421	7	
Goodwill	-	-	-	
Other Long-term Assets	17	18	(0)	
Total Assets	**$ 5,609**	**$ 5,637**	**$ (27)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 162	$ 183	$ (21)	Primarily related to decreases in power generation accruals, retention balances and other timing of payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	11	39	(28)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	8	13	(5)	
Other Current Liabilities	92	69	23	Due to reclassification of ARO liability from non-current to current liabilities and timing of interest payments.
Total Current Liabilities	304	334	(30)	
Debt - Affiliated Company	-	-	-	
Debt [1]	1,723	1,743	(20)	
Total Debt	1,723	1,743	(20)	
Deferred Tax Liabilities	866	860	6	
Investment Tax Credit	34	34	(0)	
Accum Provision for Pension & Related Benefits	43	43	(0)	
Asset Retirement Obligation	135	151	(15)	Primarily due to a reclassification of ARO from non-current to current liabilities.
Regulatory Liabilities Non Current	365	362	3	
Derivative Liability	47	42	5	
Other Liabilities	90	90	0	
Total Deferred Credits and Other Liabilities	1,581	1,582	(1)	
Equity	2,001	1,978	23	
Total Liabilities and Equity	**$ 5,609**	**$ 5,637**	**$ (27)**	

[1] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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Balance Sheet - KU

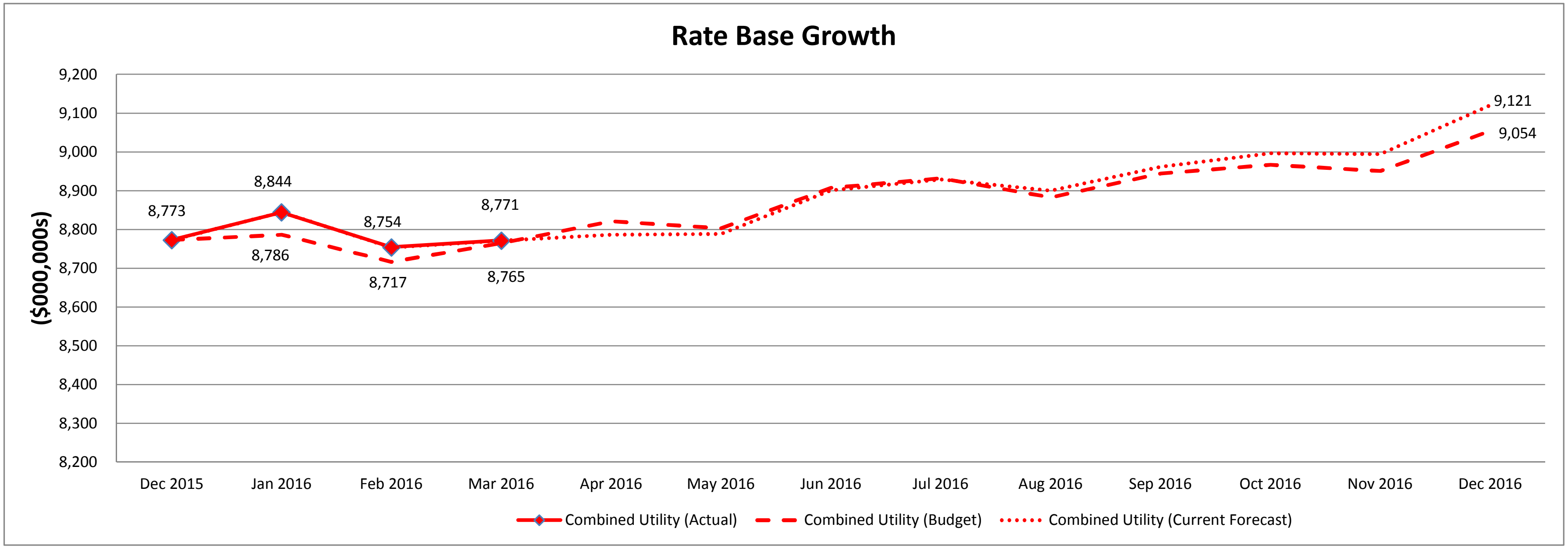
March 2016

($ Millions)

	3/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 17	$ 5	$ 12	Budget included increased payments related to Accounts Payable and Capital Expenditures.
Accounts Receivable (Trade)	209	214	(5)	
Inventory	157	150	7	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	10	35	(25)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	13	17	(4)	
Total Current Assets	405	422	(16)	
Property, Plant, and Equipment	6,614	6,620	(6)	
Intangible Assets	13	11	2	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	311	308	3	
Goodwill	-	-	-	
Other Long-term Assets	50	50	0	
Total Assets	**$ 7,393**	**$ 7,411**	**$ (18)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 119	$ 130	$ (11)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	27	26	1	
Derivative Liability	-	-	-	
Accrued Taxes	12	40	(28)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	22	18	4	
Other Current Liabilities	96	89	7	
Total Current Liabilities	277	303	(26)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,357	2,362	(5)	
Total Debt	2,357	2,362	(5)	
Deferred Tax Liabilities	1,091	1,087	4	
Investment Tax Credit	93	93	0	
Accum Provision for Pension & Related Benefits	37	38	(0)	
Asset Retirement Obligation	334	340	(6)	
Regulatory Liabilities Non Current	455	448	7	
Derivative Liability	-	-	-	
Other Liabilities	60	59	1	
Total Deferred Credits and Other Liabilities	2,070	2,064	6	
Equity	2,690	2,682	8	
Total Liabilities and Equity	**$ 7,393**	**$ 7,411**	**$ (18)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.



Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
Dec 2015
Jan 2016
Feb 2016
Mar 2016
Apr 2016
May 2016
Jun 2016
Jul 2016
Aug 2016
Sep 2016
Oct 2016
Nov 2016
Dec 2016
8,773
8,844
8,754
8,771
8,786
8,717
8,765
9,121
9,054
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

Combined KU and LG&E ROE — March 2016

KU and LG&E Combined

Reconciliation of Allowed Return to

12 months ended Mar-2016 Regulatory Return

and ROE from Ongoing Operations

Allowed Return [1]		10.1%	
Adjustments (net of tax):			
Change in capitalization - non mechanism	-0.4%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.0%		Mechanisms have a real-time return
Change in weighted cost of debt	0.0%		Lower interest rate
Change in margins	-0.4%		Lower sales
Change in allowed expenses	-0.1%		Inflationary Increases
		-0.8%	
Actual Regulated ROE		9.3%	

(1) Based on the most recent base rate filings with test years ending 6/30/16 KPSC, 12/31/14 FERC, 12/31/14 VA.

Note: The allowed return is a blended rate of the previous authorized ROE of 10.25% before 7/1/15 and from the settlement for TYE 6/30/16 which did not provide a specific return on equity with respect to base rates; however, the average customer's monthly bill will reflect an authorized 10% return on equity investment related to the environmental cost recovery mechanism and the gas line tracker mechanism.

Performance Report

April 2016

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Kentucky Regulated Dashboard — April 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.56	1.13	0.80	1.21	1.38	1.22
Employee lost-time incidents	0	1	1	1	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,419	2,444	10,883	11,489	34,357	34,964
Utility EFOR	2.6%	5.7%	4.2%	5.7%	N/A	5.7%
Utility EAF	69.2%	79.8%	82.8%	79.8%	N/A	82.3%
Steam Fleet Commercial Availability	88.4%	92.8%	95.2%	92.8%	N/A	92.8%
Combined SAIFI	0.12	0.10	0.31	0.30	N/A	1.03
Combined SAIDI (minutes)	8.46	7.92	26.12	26.69	N/A	94.09
GwH Sales						
Residential	624	700	3,496	3,743	10,599	10,847
Commercial	576	556	2,456	2,430	7,819	7,793
Industrial	786	772	3,050	3,137	10,003	10,089
Municipals	133	134	603	615	1,874	1,886
Other	208	206	881	886	2,792	2,798
Off-System Sales	18	5	54	246	105	322
Total	2,345	2,373	10,540	11,057	33,192	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.34%			
Commercial			1.05%			
Industrial			-2.88%			
Municipal			0.98%			
Other			0.17%			
Total			-1.31%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[2]	N/A	N/A	9.4%	9.5%	9.8%	9.8%
Electric Margins	$134	$138	$597	$610	$1,856	$1,870
Gas Margins	13	13	75	78	172	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$2	$0	$12	$7	$16	$9
ECR	28	58	75	153	370	404
Generation	13	15	31	40	127	117
Transmission	7	13	21	31	91	90
Electric Distribution	13	14	49	50	173	169
Gas Distribution	6	6	23	24	89	86
Customer Services	1	1	5	6	21	20
IT and Other	4	6	18	19	61	59
Total	$73	$113	$235	$330	$948	$955
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$43	$43	$150	$154	$457	$459
General Counsel & HR	3	3	14	14	42	42
Finance, IT, & Supply Chain	6	7	27	29	86	86
Burdens & Other Charges	13	12	52	50	141	144
Total	$66	$66	$243	$247	$726	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,448	3,581	3,448	3,581	3,587	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	0	7	N/A	16
NERC Possible Violations[4]	0	1	0	2	N/A	8

Variance Explanations

• YTD lower margins primarily due to warmer than normal weather during the first quarter, resulting in lower YTD retail electric base energy and demand revenue of $16 million and $3 million lower gas margins. This was partially offset by $2 million higher ECR margins.

• Current month capital expenditures were lower, primarily due to permitting delays related to CCR projects at Trimble County.

• YTD capital expenditures were lower, primarily due to the timing of Environmental Cost Recovery (ECR) spending on Environmental Air projects at Mill Creek and permitting delays related to CCR projects at Trimble County.

Major Developments

• LG&E and KU ranked second in its peer group in the first quarter 2016 Residential Customer Satisfaction survey with a “top two box” score of 59.4 percent.

The following represents KPSC items which were addressed during the month:

• Governor Matt Bevin has appointed Robert Cicero, a Florence businessman, to serve as a Commissioner on the KPSC. Cicero replaces Roger Thomas on the three-member Commission which allows for the quorum it needs to issue orders. His appointment is for the remainder of Thomas's term which expires on July 1, 2016. Cicero is also eligible for reappointment to a full four-year term. The KPSC has one vacancy for a Commissioner yet to be announced as well as an open Executive Director position.

• The KPSC approved plans for LG&E and KU to own and operate electric vehicle charging stations within its service territories. Each utility will install 10 charging stations at different locations for public access. The entire cost of the charging stations will be paid by those who request the stations or the users of the charging service.

• The KPSC also decided not to adopt any of the federal smart grid standards, however, it will allow utilities flexibility in deciding how to deploy these systems.

Significant Future Events

• The 2016 ECR Plan proceeding before the KPSC is continuing as planned. Public meetings will be held during May with a formal hearing scheduled for June 14.

• The Brown Solar and Mill Creek baghouse projects are expected to be completed in June.

(1) Full year forecast amount shown represents target.

(2) Excludes goodwill and other purchase accounting adjustments. Represents trailing twelve months.

(3) Net of cost recovery mechanisms.

(4) The possible violation issues are believed to be minimal risk.

Attachment to Filing Requirement
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Blake

Income Statement: Actual vs. Budget (Month)

April 2016

($ Millions)

	MTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 205	$ 220	$ (15)	Due to lower volumes driven by lower than expected heating demand early in the month resulting from warmer than expected temperatures.
Gas Revenues	21	22	(2)	
Total Revenues	226	242	(16)	
Cost of Sales:				
Fuel Electric Costs	55	64	9	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	8	10	2	
Purchased Power	5	4	(0)	
Other Electric Cost	11	13	1	
Total Cost of Sales	79	91	12	
Gross Margin:				
Electric Margin	134	138	(4)	
Gas Margin	13	13	0	
Total Gross Margin	147	151	(4)	
Operating Expenses:				
O&M	66	65	(0)	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	99	100	1	
Other income (expense)	(1)	(1)	(0)	
EBIT	47	50	(3)	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	29	32	(3)	
Income Tax Expense	11	12	1	
Net Income (loss) from ongoing operations	**18**	**20**	**$ (2)**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 18	$ 20	$ (2)	
KY Regulated Financing Costs	(3)	(2)	(0)	
KY Regulated Net Income	$ 16	$ 18	$ (2)	
Earnings Per Share - Ongoing	$ 0.02	$ 0.03	$ (0.00)	

Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — April 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 915	$ 980	$ (66)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	138	164	(26)	See Gas Supply Expenses explanation below.
Total Revenues	1,053	1,145	(92)	
Cost of Sales:				
Fuel Electric Costs	253	298	45	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	63	86	23	Due to lower net purchases and lower gas prices.
Purchased Power	18	18	(0)	
Other Electric Cost	47	55	8	Due to lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	381	457	76	
Gross Margin:				
Electric Margin	597	610	(13)	Lower margins primarily due to warmer than normal weather during the first quarter, resulting in lower YTD retail electric base energy and demand revenue of $16 million. This was partially offset by $2 million higher ECR margins.
Gas Margin	75	78	(3)	
Total Gross Margin	672	688	(16)	
Operating Expenses:				
O&M	243	247	3	
Depreciation & Amortization	116	119	3	
Taxes, Other than Income	18	19	0	
Total Operating Expenses	377	384	7	
Other income (expense)	(4)	(3)	(0)	
EBIT	291	301	(10)	
Interest Expense	70	72	2	
Income from Ongoing Operations before income taxes	220	228	(8)	
Income Tax Expense	83	87	5	Lower income taxes primarily due to lower pre-tax income.
Net Income (loss) from ongoing operations	**138**	**141**	**$ (3)**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 138	$ 141	$ (3)	
KY Regulated Financing Costs	(10)	$ (10)	(0)	
KY Regulated Net Income	$ 128	$ 131	$ (3)	
Earnings Per Share - Ongoing	$ 0.19	$ 0.19	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

April 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 352	$ 369	$ (17)	Primarily due to lower off system sales and FAC revenue which were offset by lower related fuel costs below.
Gas Revenues	138	164	(26)	See Gas Supply Expenses explanation below.
Total Revenues	490	533	(43)	
Cost of Sales:				
Fuel Electric Costs	101	116	15	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	63	86	23	Due to lower net purchases and lower gas prices.
Purchased Power	16	15	(0)	
Other Electric Cost	18	22	4	
Total Cost of Sales	198	239	41	
Gross Margin:				
Electric Margin	217	216	2	
Gas Margin	75	78	(3)	
Total Gross Margin	293	294	(2)	
Operating Expenses:				
O&M	105	109	4	
Depreciation & Amortization	47	48	1	
Taxes, Other than Income	9	9	0	
Total Operating Expenses	161	167	6	
Other income (expense)	(2)	(2)	(1)	
EBIT	129	126	3	
Interest Expense	23	24	0	
Income from Ongoing Operations before income taxes	106	102	4	
Income Tax Expense	41	39	(1)	
Net Income (loss) from ongoing operations	**65**	**63**	**$ 2**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

April 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 580	$ 638	$ (59)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	-	-	-	
Total Revenues	580	638	(59)	
Cost of Sales:				
Fuel Electric Costs	153	186	33	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	-	-	-	
Purchased Power	19	26	7	Lower purchased power due to mild weather.
Other Electric Cost	29	33	4	
Total Cost of Sales	201	245	44	
Gross Margin:				
Electric Margin	379	394	(15)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	379	394	(15)	
Operating Expenses:				
O&M	128	128	(0)	
Depreciation & Amortization	69	70	2	
Taxes, Other than Income	9	9	0	
Total Operating Expenses	206	208	2	
Other income (expense)	(1)	(2)	0	
EBIT	172	184	(13)	
Interest Expense	31	32	1	
Income from Ongoing Operations before income taxes	140	152	(12)	
Income Tax Expense	53	58	5	
Net Income (loss) from ongoing operations	**87**	**94**	**$ (7)**	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD

($ Millions)

April 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	63	67	(4)
Demand	44	44	1
Base Service Charge	14	14	(0)
Rate Mechanisms	16	16	0
Other Rev/Cost of Sales	(0)	0	(0)
Other Margin Items	(3)	(2)	(1)
	134	138	(4)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	25	26	(1)
Demand	14	14	1
Base Service Charge	6	6	(0)
Rate Mechanisms	8	8	0
Other Rev/Cost of Sales	(0)	(0)	(0)
Other Margin Items	(2)	(2)	(0)
	51	52	(1)

KU Electric Margin

	Actual	Budget	Variance
Base Energy	38	41	(3)
Demand	30	30	(0)
Base Service Charge	8	8	0
Rate Mechanisms	8	8	(0)
Other Rev/Cost of Sales	0	0	0
Other Margin Items	(1)	(0)	(0)
	83	87	(4)

LKE Base Energy Price/Vol Variance

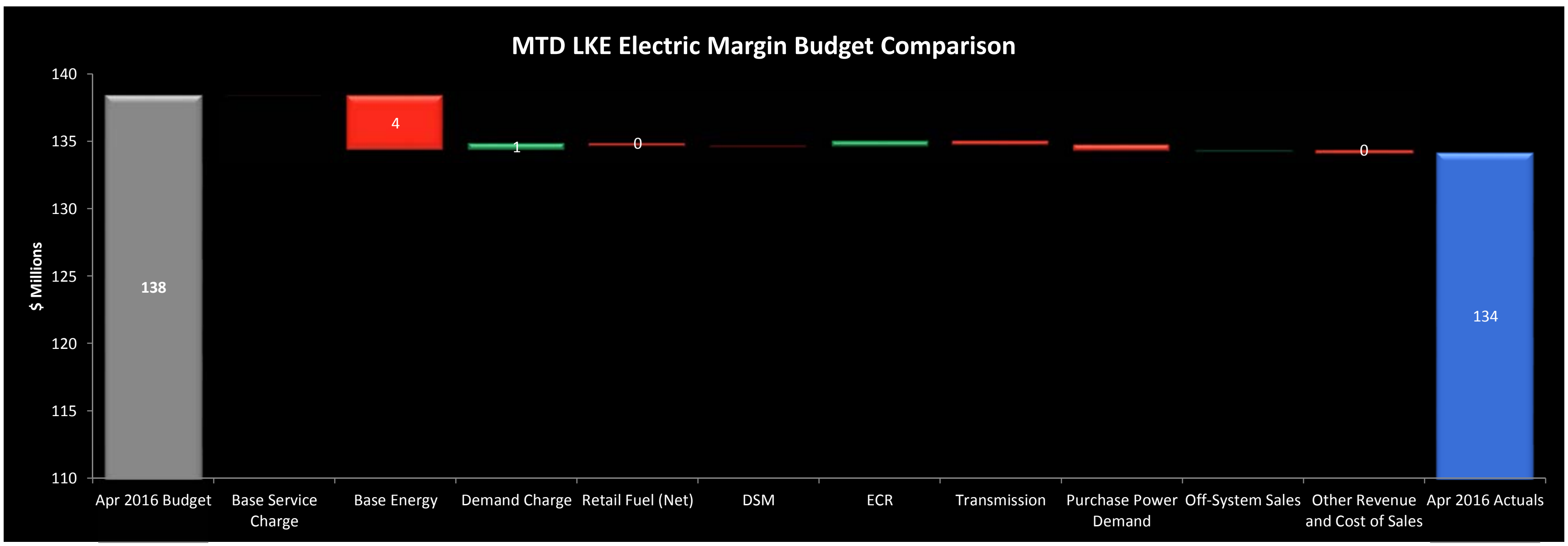
	Volume	Price	Total Variance
Residential	(4)	0	(4)
Commercial	1	(1)	(1)
Industrial	0	0	0
Public Authority	0	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	0	0
Other	0	0	0
	(3)	(1)	(4)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(1)	0	(1)
Commercial	1	(1)	(0)
Industrial	0	0	0
Public Authority	0	(0)	0
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	(1)	(0)	(1)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(3)	0	(2)
Commercial	0	(1)	(1)
Industrial	0	0	0
Public Authority	(0)	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	0	0
Other	0	0	0
	(3)	(0)	(3)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Electric Gross Margin Analysis - YTD

($ Millions)

April 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	313	328	(14)
Demand	174	175	(1)
Base Service Charge	55	55	(0)
Rate Mechanisms	62	62	1
Other Rev/Cost of Sales	(1)	(3)	2
Other Margin Items	(7)	(7)	(0)
	597	610	(13)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	115	117	(2)
Demand	56	55	2
Base Service Charge	22	23	(0)
Rate Mechanisms	31	30	2
Other Rev/Cost of Sales	(0)	(1)	1
Other Margin Items	(7)	(7)	0
	217	216	2

KU Electric Margin

	Actual	Budget	Variance
Base Energy	199	211	(12)
Demand	117	120	(3)
Base Service Charge	32	32	0
Rate Mechanisms	31	32	(1)
Other Rev/Cost of Sales	(0)	(2)	1
Other Margin Items	0	0	(0)
	379	394	(15)

LKE Base Energy Price/Vol Variance

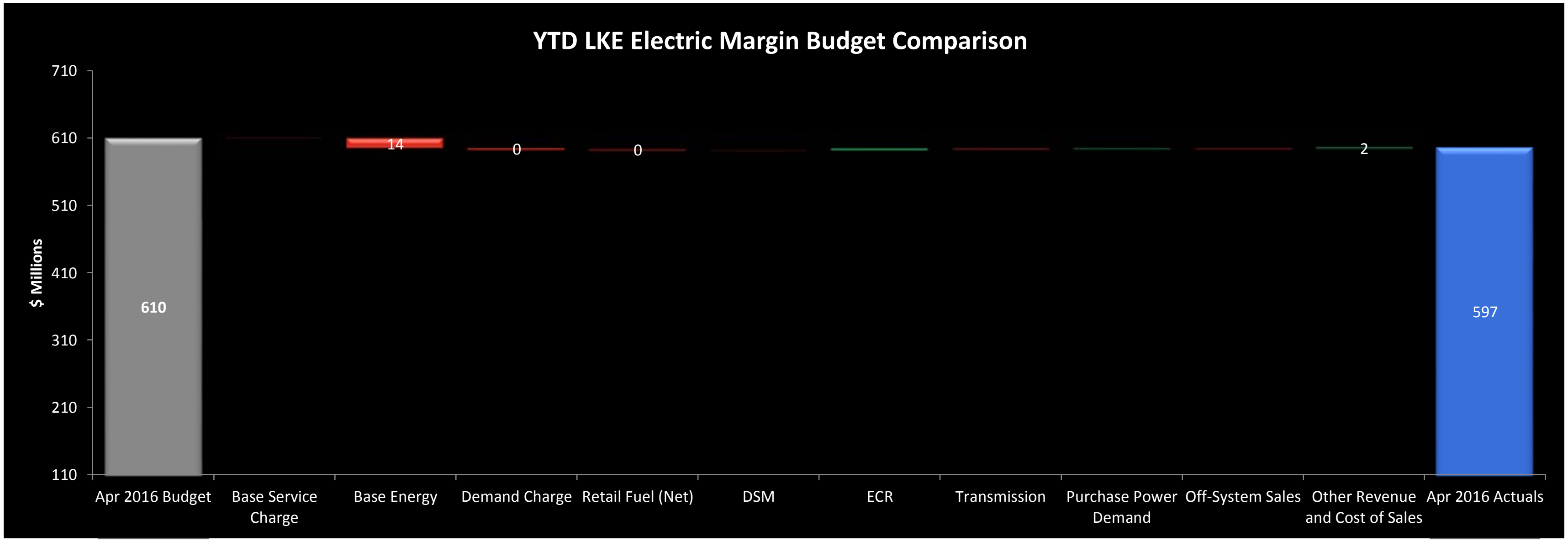
	Volume	Price	Total Variance
Residential	(13)	2	(11)
Commercial	1	(3)	(3)
Industrial	(1)	1	(0)
Public Authority	(0)	0	0
Street Lights	(1)	0	(0)
Municipals	(0)	(0)	(1)
Other	0	0	0
	(14)	(1)	(14)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(4)	1	(3)
Commercial	1	(1)	0
Industrial	(0)	0	0
Public Authority	0	0	1
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(2)	0	(2)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(9)	1	(8)
Commercial	(1)	(2)	(3)
Industrial	(0)	0	(0)
Public Authority	(0)	(0)	(0)
Street Lights	(1)	0	(0)
Municipals	(0)	(0)	(1)
Other	0	0	0
	(11)	(1)	(12)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin — April 2016

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**0**	**$ 21**	**$ 21**		**0**
Gas Supply Costs								
Gas Supply Costs	(7)	(9)	$ 2		(60)	(82)	$ 22	
GSC Revenue	7	9	$ (2)		60	82	$ (22)	
Net Gas Supply Costs				**0**				**0**
Retail Gas (a)	**5**	**6**		**(1)**	**46**	**52**		**(6)**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**-**
DSM	**-**	**-**		**-**	**-**	**-**		**-**
GLT	**1**	**1**		**0**	**5**	**5**		**0**
WNA	**1**	**-**		**1**	**3**	**-**		**3**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**0**
Gas Margin Variance				**$ 0**				**$ (3)**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 3	1,167,438	$ 2.87	$ 4	1,280,562	$ 2.87	($0.3)	($0.3)	($0.0)
Commercial	1	519,862	1.93	1	558,580	2.11	($0.2)	($0.1)	($0.1)
Industrial	0	77,201	1.72	0	94,427	2.00	($0.1)	($0.0)	($0.0)
Public Authority	0	59,954	1.77	0	89,655	2.00	($0.1)	($0.1)	($0.0)
Transportation	1	989,607	0.53	0	791,594	0.49	$0.1	$0.1	$0.0
Interdepartmental	0	14,777	20.28	0	188,619	1.62	($0.0)	($0.3)	$0.3
Ultimate Consumer	$ 5	2,828,839	$ 1.91	$ 6	3,003,436	$ 1.97	($0.5)	($0.7)	$0.2

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 30	10,317,431	$ 2.87	$ 35	12,191,191	$ 2.87	($5)	$ (5)	$ (0)
Commercial	10	4,550,747	2.12	11	4,993,191	2.14	($1)	$ (1)	$ (0)
Industrial	1	457,488	2.16	1	588,291	2.15	($0)	$ (0)	$ 0
Public Authority	1	655,060	2.09	2	772,114	2.11	($0)	$ (0)	$ (0)
Transportation	3	5,168,299	0.53	2	4,708,545	0.47	$0	$0	$0
Interdepartmental	1	121,778	10.01	1	229,965	5.22	$0	($1)	$1
Ultimate Consumer	$ 46	21,270,803	$ 2.14	$ 52	23,483,297	$ 2.21	($6)	($7)	$1

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	23	23	(0)	0	0	(1)	1	(0)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	3	0	0	(0)	0	0	0
Energy Supply and Analysis	1	1	(0)	(0)	-	(0)	0	0
Generation Services	2	2	(0)	0	(0)	(0)	(0)	0
Electric Distribution	6	6	(0)	(0)	0	(0)	0	0
Gas Distribution	3	3	(0)	(0)	(0)	0	(0)	(0)
Safety and Security	0	0	0	0	(0)	0	(0)	0
Customer Services	6	6	0	(0)	0	0	0	0
Chief Operations Officer	**43**	**43**	**(0)**	**(0)**	**(0)**	**(1)**	**1**	**0**
General Counsel	3	3	(0)	(0)	0	0	(0)	(0)
Human Resources	0	1	0	(0)	-	0	0	0
General Counsel & HR	**3**	**3**	**0**	**(0)**	**0**	**0**	**(0)**	**0**
Audit Services	0	0	(0)	(0)	-	0	(0)	0
Controller	1	1	(0)	(0)	-	0	0	0
Information Technology	5	5	0	0	(0)	0	0	(0)
Supply Chain	0	0	0	(0)	(0)	0	0	0
Treasurer	(0)	1	1	(0)	-	(0)	0	1
Chief Financial Officer	**6**	**7**	**1**	**(0)**	**(0)**	**0**	**0**	**1**
Corporate	**13**	**12**	**(1)**	**(0)**	**(0)**	**0**	**(0)**	**(1)**
O&M Total MTD	**66**	**66**	**0**	**(0)**	**(0)**	**(0)**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	70	73	3	1	(0)	1	3	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	9	9	0	(0)	(0)	(0)	(0)	0
Energy Supply and Analysis	3	3	0	0	-	(0)	0	0
Generation Services	5	5	(0)	0	(0)	(1)	(0)	1
Electric Distribution	23	23	1	(0)	2	(1)	0	0
Gas Distribution	11	11	(1)	(0)	(0)	0	(0)	(0)
Safety and Security	2	2	0	0	(0)	0	0	(0)
Customer Services	27	28	0	0	0	(0)	0	(0)
Chief Operations Officer	**150**	**154**	**4**	**1**	**1**	**(1)**	**3**	**0**
General Counsel	11	12	0	0	0	(1)	0	0
Human Resources	2	2	0	(0)	-	0	(0)	0
General Counsel & HR	**14**	**14**	**0**	**0**	**0**	**(0)**	**0**	**0**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	3	3	0	(0)	-	0	(0)	0
Information Technology	19	20	1	1	(0)	0	0	0
Supply Chain	1	1	0	(0)	(0)	0	0	0
Treasurer	4	4	(0)	(0)	-	(0)	(0)	0
Chief Financial Officer	**27**	**29**	**1**	**0**	**(0)**	**0**	**0**	**1**
Corporate	**52**	**50**	**(2)**	**(2)**	**(1)**	**1**	**(0)**	**0**
O&M Total YTD	**243**	**247**	**4**	**(1)**	**0**	**(0)**	**3**	**1**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	205	206	0	(2)	1	0	(1)	1
Project Engineering	1	1	0	(0)	-	0	0	(0)
Transmission	30	30	(0)	0	0	0	0	(1)
Energy Supply and Analysis	9	9	0	(0)	-	0	(0)	(0)
Generation Services	16	15	(0)	0	0	1	0	(2)
Electric Distribution	72	73	1	0	3	(3)	(0)	(1)
Gas Distribution	34	34	0	0	(0)	0	(0)	(0)
Safety and Security	5	5	(0)	0	0	0	(0)	0
Customer Services	86	87	0	(0)	0	(0)	0	(0)
Chief Operations Officer	**457**	**459**	**2**	**(2)**	**4**	**(1)**	**(1)**	**(2)**
General Counsel	35	35	0	(0)	0	(0)	0	(0)
Human Resources	7	7	0	0	-	(0)	(0)	(0)
General Counsel & HR	**42**	**42**	**0**	**(0)**	**0**	**(0)**	**0**	**(0)**
Audit Services	2	2	(0)	(0)	-	0	(0)	0
Controller	10	10	(0)	0	-	(0)	0	(0)
Information Technology	60	60	0	(1)	0	0	(0)	1
Supply Chain	4	4	(0)	0	0	(0)	0	0
Treasurer	11	11	0	0	-	0	0	(1)
Chief Financial Officer	**86**	**86**	**0**	**0**	**0**	**0**	**(0)**	**(0)**
Corporate	**141**	**144**	**3**	**0**	**0**	**(0)**	**0**	**(3)**
O&M Total Full Year	**726**	**731**	**5**	**(1)**	**4**	**(2)**	**(1)**	**(5)**

Note: Schedules may not sum due to rounding.

Financing Activities							April 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance		Full Year Forecast	Full Year Budget	Full Year Variance
PCB							
Beg Bal	$ 923.9	$ 923.9	$ 0.0		$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	(0.0)		923.8	923.8	(0.0)
Ave Bal	**$ 923.9**	**$ 923.9**	**$ 0.0**		**$ 923.8**	**$ 923.8**	**$ (0.0)**
Interest Exp	**$ 4.0**	**$ 4.6**	**$ 0.7**		**$ 13.2**	**$ 13.9**	**$ 0.7**
Rate	**1.28%**	**1.49%**	**0.21%**		**1.41%**	**1.48%**	**0.07%**
FMB/Sr Nts							
Beg Bal	$ 4,210.0	$ 4,210.0	$ -		$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-		4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**		**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 60.0**	**$ 58.4**	**$ (1.6)**		**$ 176.9**	**$ 175.3**	**$ (1.6)**
Rate	**4.24%**	**4.13%**	**-0.11%**		**4.13%**	**4.10%**	**-0.04%**
Short-term Debt							
Beg Bal	$ 318.9	$ 215.2	$ (103.7)		$ 451.8	$ 347.7	$ (104.1)
End Bal	252.2	260.9	8.7		452.3	347.7	(104.6)
Ave Bal	**$ 285.6**	**$ 238.0**	**$ (47.5)**		**$ 452.1**	**$ 347.7**	**$ (104.4)**
Interest Exp	**$ 1.3**	**$ 1.6**	**$ 0.3**		**$ 5.0**	**$ 4.8**	**$ (0.2)**
Rate	**1.33%**	**2.01%**	**0.67%**		**1.08%**	**1.35%**	**0.26%**
Unamortized Debt Expense Bonds							
Beg Bal	$ (46.3)	$ (44.2)	$ 2.2		$ (42.2)	$ (39.6)	$ 2.6
End Bal	(45.0)	(45.4)	(0.4)		(40.5)	(39.6)	0.9
Ave Bal	**$ (45.7)**	**$ (44.8)**	**$ 0.9**		**$ (41.4)**	**$ (39.6)**	**$ 1.8**
Total End Bal	**$ 5,341.0**	**$ 5,349.3**	**$ 8.3**		**$ 5,545.7**	**$ 5,441.9**	**$ (103.8)**
Total Average Bal	**$ 5,373.7**	**$ 5,327.1**	**$ (46.6)**		**$ 5,544.5**	**$ 5,441.9**	**$ (102.7)**
Total Expense Excl I/C (1)	**$ 70.3**	**$ 72.4**	**$ 2.1**		**$ 214.0**	**$ 217.2**	**$ 3.1**
Rate	**3.86%**	**4.01%**	**0.15%**		**3.77%**	**3.90%**	**0.13%**

(1) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(2)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 154		$ 146
LG&E	500	77		423
KU	598	21	$ 198	379
TOTAL	$ 1,398	$ 252	$ 198	$ 948

(2) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	17%	17%	27%	26%	25%	24%
CFO pre-WC + Interest / Interest	5.7	5.6	8.4	8.3	7.7	7.4
CFO pre-WC - Dividends / Debt	15%	15%	27%	25%	17%	16%
Debt to Capitalization[2]	47%	47%	38%	39%	38%	39%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

April 2016

($ Millions)

	4/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 22	$ 15	$ 8	Budget included increased payments related to Accounts Payable and Capital Expenditures.
Accounts Receivable (Trade)	340	352	(13)	
Inventory	277	254	23	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	22	57	(35)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	45	47	(2)	
Total Current Assets	706	724	(18)	
Property, Plant, and Equipment	11,482	11,572	(90)	
Intangible Assets	114	109	5	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	749	735	13	
Goodwill	997	997	-	
Other Long-term Assets	76	78	(1)	
Total Assets	**$ 14,125**	**$ 14,217**	**$ (91)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 244	$ 270	$ (26)	Primarily related to timing of fuel and other payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	54	52	2	
Derivative Liability	6	5	1	
Accrued Taxes	27	78	(51)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	31	31	(0)	
Other Current Liabilities	230	218	12	
Total Current Liabilities	592	654	(63)	
Debt - Affiliated Company	554	412	143	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016.
Debt [(1)]	4,787	4,938	(151)	
Total Debt	5,341	5,349	(8)	
Deferred Tax Liabilities	1,532	1,522	10	
Investment Tax Credit	127	127	0	
Accum Provision for Pension & Related Benefits	269	267	2	
Asset Retirement Obligation	470	492	(22)	
Regulatory Liabilities Non Current	914	899	15	
Derivative Liability	46	42	4	
Other Liabilities	207	205	3	
Total Deferred Credits and Other Liabilities	3,566	3,554	11	
Equity	4,627	4,659	(32)	
Total Liabilities and Equity	**$ 14,125**	**$ 14,217**	**$ (91)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

April 2016

($ Millions)

	4/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 6	$ 5	$ 1	
Accounts Receivable (Trade)	146	152	(6)	
Inventory	118	96	22	Higher actual due to higher than budgeted purchases.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	9	20	(11)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	37	38	(1)	
Total Current Assets	317	311	6	
Property, Plant, and Equipment	4,855	4,915	(60)	
Intangible Assets	6	3	3	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	428	420	8	
Goodwill	-	-	-	
Other Long-term Assets	17	18	(1)	
Total Assets	**$ 5,624**	**$ 5,668**	**$ (44)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 169	$ 178	$ (10)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	19	41	(22)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	9	13	(4)	
Other Current Liabilities	86	74	12	Due to reclassification of ARO liability from non-current to current liabilities.
Total Current Liabilities	314	337	(22)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,718	1,766	(48)	
Total Debt	1,718	1,766	(48)	
Deferred Tax Liabilities	866	860	6	
Investment Tax Credit	34	34	(0)	
Accum Provision for Pension & Related Benefits	43	42	1	
Asset Retirement Obligation	135	151	(16)	Primarily due to a reclassification of ARO from non-current to current liabilities.
Regulatory Liabilities Non Current	365	359	6	
Derivative Liability	46	42	4	
Other Liabilities	92	91	1	
Total Deferred Credits and Other Liabilities	1,581	1,579	2	
Equity	2,011	1,986	25	
Total Liabilities and Equity	**$ 5,624**	**$ 5,668**	**$ (44)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

Balance Sheet - KU

April 2016

($ Millions)

	4/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 16	$ 5	$ 11	Budget included increased payments related to Accounts Payable and Capital Expenditures.
Accounts Receivable (Trade)	192	199	(7)	
Inventory	159	158	1	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	12	37	(24)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	21	22	(2)	
Total Current Assets	400	421	(21)	
Property, Plant, and Equipment	6,620	6,650	(30)	
Intangible Assets	13	11	2	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	315	311	4	
Goodwill	-	-	-	
Other Long-term Assets	50	51	(0)	
Total Assets	**$ 7,398**	**$ 7,443**	**$ (45)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 118	$ 131	$ (12)	Primarily related to timing of fuel and other payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	28	26	1	
Derivative Liability	-	-	-	
Accrued Taxes	14	40	(26)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	22	18	4	
Other Current Liabilities	99	96	2	
Total Current Liabilities	281	312	(31)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,344	2,372	(27)	
Total Debt	2,344	2,372	(27)	
Deferred Tax Liabilities	1,091	1,087	4	
Investment Tax Credit	92	92	0	
Accum Provision for Pension & Related Benefits	38	38	0	
Asset Retirement Obligation	335	341	(6)	
Regulatory Liabilities Non Current	454	445	10	
Derivative Liability	-	-	-	
Other Liabilities	60	59	1	
Total Deferred Credits and Other Liabilities	2,071	2,062	9	
Equity	2,702	2,698	4	
Total Liabilities and Equity	**$ 7,398**	**$ 7,443**	**$ (45)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

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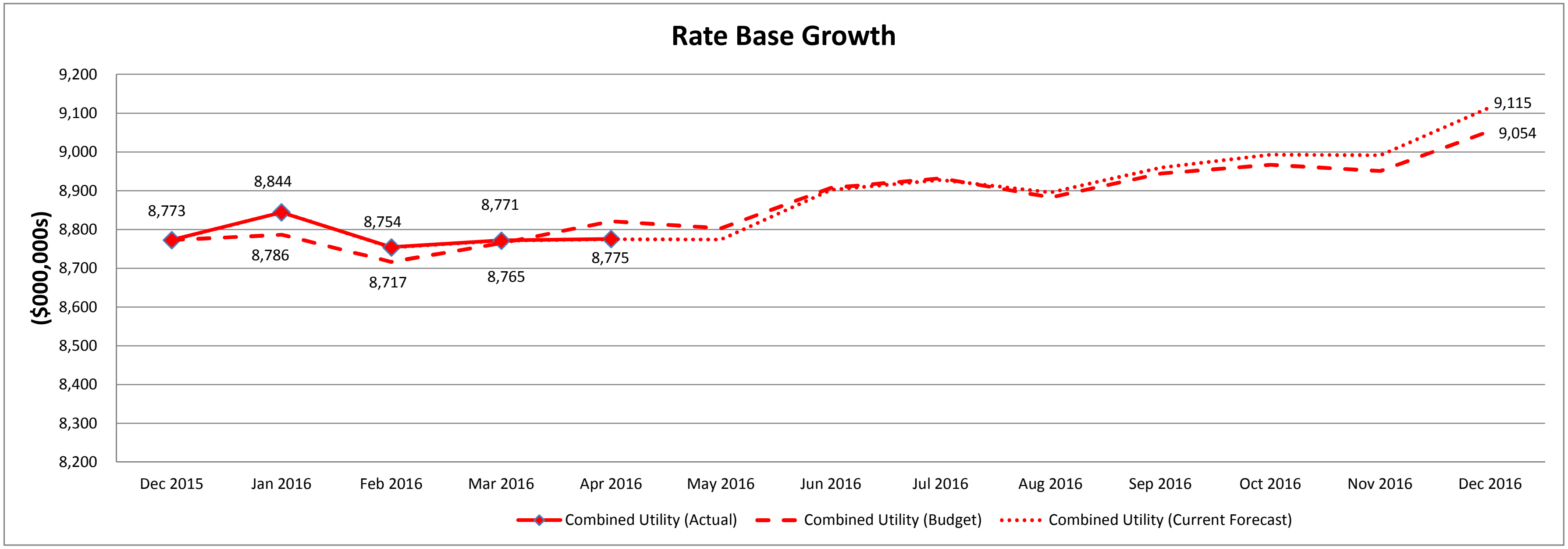

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Performance Report

May 2016

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Kentucky Regulated Dashboard — May 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.11	0.53	0.86	1.04	1.38	1.22
Employee lost-time incidents	0	1	1	2	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,492	2,719	13,375	14,209	34,130	34,964
Utility EFOR	7.3%	5.7%	4.8%	5.7%	N/A	5.7%
Utility EAF	78.1%	80.2%	81.8%	80.2%	N/A	82.3%
Steam Fleet Commercial Availability	87.4%	92.8%	93.7%	92.8%	N/A	92.8%
Combined SAIFI	0.09	0.11	0.40	0.41	N/A	1.03
Combined SAIDI (minutes)	9.89	8.84	36.00	35.54	N/A	94.09
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	681	682	4,177	4,425	10,599	10,847
Commercial	611	640	3,067	3,070	7,790	7,793
Industrial	781	900	3,831	4,037	9,884	10,089
Municipals	139	146	742	761	1,867	1,886
Other	222	239	1,103	1,125	2,775	2,798
Off-System Sales	8	28	62	274	100	322
Total	2,442	2,635	12,982	13,692	33,014	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.45%			
Commercial			1.18%			
Industrial			-3.70%			
Municipal			0.84%			
Other			0.22%			
Total			-1.57%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$139	$143	$736	$753	$1,851	$1,870
Gas Margins	10	10	85	89	172	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$2	$0	$13	$7	$16	$9
ECR	21	33	96	186	370	404
Generation	14	17	45	57	122	117
Transmission	7	6	29	37	91	90
Electric Distribution	14	16	62	65	171	169
Gas Distribution	7	8	30	32	89	86
Customer Services	1	1	7	7	21	20
IT and Other	4	5	23	24	61	59
Total	$70	$86	$305	$415	$941	$955
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$37	$38	$187	$192	$457	$459
General Counsel & HR	3	3	17	17	42	42
Finance, IT, & Supply Chain	6	7	34	36	86	86
Burdens & Other Charges	12	12	64	63	141	144
Total	$58	$61	$301	$308	$726	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,468	3,583	3,468	3,583	3,582	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	2	0	9	N/A	16
NERC Possible Violations[3]	1	0	1	2	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[4]	9.4%	9.8%	9.8%

Variance Explanations

• Current month higher EFOR primarily due to generator bearing and rotor vibration issues on Trimble County Unit 2.

• YTD lower margins primarily due to warmer than normal weather during the first quarter, resulting in lower YTD retail electric base energy and demand revenue of $19 million and $3 million lower gas margins. This was partially offset by $2 million lower cost of production.

• YTD lower O&M primarily due to timing of plant maintenance, storm restoration and vegetation management.

• Current month capital expenditures were lower, primarily due to timing of Environmental Cost Recovery (ECR) spending related to CCR projects at Trimble County.

• YTD capital expenditures were lower, primarily due to the timing of ECR spending on Environmental Air projects at Mill Creek, permitting delays related to CCR projects at Trimble County and various other generation projects.

Major Developments

• LKE reached a unanimous settlement agreement in the ECR proceeding with the Attorney General and Kentucky Industrial Utility Customers. The agreement provides for full recovery of and on all projects in the filing through the ECR mechanism including the 10 percent return on equity established in the last base rate case. The settlement agreement was filed on June 13 with a public hearing at the KPSC on June 14. While the 10 percent return on equity was agreed to by all parties in the case, KPSC counsel and the Commissioners raised concerns during the hearing about the return on equity in light of lower returns awarded to utilities across the country. The Company provided supportive responses during the hearing and will reiterate its position in briefs to be filed later this month. An Order from the KPSC is expected around the end of July.

• LKE achieved two major construction milestones as the Brown Solar project and Mill Creek Unit 3 WFGD and baghouse projects were recently placed in service. The Brown Solar project has reached 10 MW on several occasions and Mill Creek Unit 3 represents the last major unit in the environmental air construction program.

• In FERC related litigation with the city of Paris, Administrative Law Judge H. Peter Young issued an Initial Decision ruling in KU's favor on all issues. Specifically, Judge Young ruled that KU's actions were consistent with the requirements of the existing agreement and were just, reasonable and not unduly discriminatory. Judge Young also agreed that KU acted properly by providing 60 days' notice of the proposed changes and rejected arguments that they constituted a termination of service that required three years notice. As a result of the ruling, KU will not be required to issue any refunds for capacity payments dating back to July 2014, as requested by Paris and FERC Trial Staff.

• LKE's interactive voice response (IVR) system has been honored as the best among combined utilities in the 2016 Energy Utility IVR Benchmark Report. LG&E and KU's wellness initiatives have also been recognized with two awards at the 2016 Worksite Wellness Conference.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms.

(3) The possible violation issues are believed to be minimal risk.

(4) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — May 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 213	$ 231	$ (19)	Due to lower volumes driven by cooler than expected average temperatures and lower industrial sales volumes including the loss of [redacted]) as a customer.
Gas Revenues	16	17	(1)	
Total Revenues	228	248	(20)	
Cost of Sales:				
Fuel Electric Costs	56	69	13	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	5	7	1	
Purchased Power	5	5	(1)	
Other Electric Cost	12	15	3	
Total Cost of Sales	79	95	16	
Gross Margin:				
Electric Margin	139	143	(4)	
Gas Margin	10	10	(0)	
Total Gross Margin	150	153	(4)	
Operating Expenses:				
O&M	58	61	3	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	92	95	3	
Other income (expense)	(0)	(0)	(0)	
EBIT	58	58	(0)	
Interest Expense	17	18	1	
Income from Ongoing Operations before income taxes	40	40	0	
Income Tax Expense	15	15	(0)	
Net Income (loss) from ongoing operations	**25**	**24**	**$ 0**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	(0)	
Net Income (loss)	$ 25	$ 24	$ 0	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 22	$ 22	$ 0	
Earnings Per Share - Ongoing	$ 0.03	$ 0.03	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated May 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,127	$ 1,212	$ (85)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	154	181	(27)	See Gas Supply Expenses explanation below.
Total Revenues	1,281	1,393	(112)	
Cost of Sales:				
Fuel Electric Costs	309	367	58	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	68	93	24	Due to lower net purchases and lower gas prices.
Purchased Power	24	23	(1)	
Other Electric Cost	59	70	11	Due to lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	460	551	92	
Gross Margin:				
Electric Margin	736	753	(17)	Lower margins primarily due to warmer than normal weather during the first quarter, resulting in lower YTD retail electric base energy and demand revenue of $19 million. This was partially offset by $2 million lower cost of production.
Gas Margin	85	89	(3)	
Total Gross Margin	821	842	(20)	
Operating Expenses:				
O&M	301	307	6	Lower O&M primarily due to timing of plant maintenance, storm restoration and vegetation management.
Depreciation & Amortization	145	149	4	
Taxes, Other than Income	23	23	0	
Total Operating Expenses	469	479	10	
Other income (expense)	(4)	(4)	(0)	
EBIT	348	358	(11)	
Interest Expense	88	90	3	
Income from Ongoing Operations before income taxes	260	268	(8)	
Income Tax Expense	98	102	4	
Net Income (loss) from ongoing operations	**162**	**166**	**$ (3)**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 162	$ 165	$ (3)	
KY Regulated Financing Costs	(13)	$ (12)	(0)	
KY Regulated Net Income	$ 150	$ 153	$ (3)	
Earnings Per Share - Ongoing	$ 0.22	$ 0.22	$ (0.01)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E

May 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 438	$ 460	$ (22)	Primarily due to lower off system sales and FAC revenue which were offset by lower related fuel costs below.
Gas Revenues	154	181	(27)	See Gas Supply Expenses explanation below.
Total Revenues	592	641	(50)	
Cost of Sales:				
Fuel Electric Costs	121	139	17	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	68	93	24	Due to lower net purchases and lower gas prices.
Purchased Power	21	22	1	
Other Electric Cost	22	27	5	Due to lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	233	280	47	
Gross Margin:				
Electric Margin	273	273	1	
Gas Margin	85	89	(3)	
Total Gross Margin	359	361	(3)	
Operating Expenses:				
O&M	133	138	4	
Depreciation & Amortization	59	60	2	
Taxes, Other than Income	12	12	0	
Total Operating Expenses	204	210	6	
Other income (expense)	(2)	(2)	(1)	
EBIT	153	150	3	
Interest Expense	29	29	0	
Income from Ongoing Operations before income taxes	124	120	3	
Income Tax Expense	47	46	(1)	
Net Income (loss) from ongoing operations	**76**	**74**	**$ 2**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

May 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 708	$ 782	$ (74)	Due to lower volumes driven by unfavorable weather.
Gas Revenues	-	-	-	
Total Revenues	708	782	(74)	
Cost of Sales:				
Fuel Electric Costs	188	232	43	Primarily due to lower commodity costs and lower volume usage due to decreased generation.
Gas Supply Expenses	-	-	-	
Purchased Power	21	27	6	Lower purchased power due to mild weather.
Other Electric Cost	36	43	6	Due to lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	246	302	56	
Gross Margin:				
Electric Margin	463	480	(18)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	463	480	(18)	
Operating Expenses:				
O&M	156	158	2	
Depreciation & Amortization	86	88	2	
Taxes, Other than Income	12	12	0	
Total Operating Expenses	254	258	4	
Other income (expense)	(2)	(2)	0	
EBIT	207	220	(13)	
Interest Expense	39	41	1	
Income from Ongoing Operations before income taxes	168	179	(11)	
Income Tax Expense	64	68	5	Lower income taxes primarily due to lower pre-tax income.
Net Income (loss) from ongoing operations	**104**	**111**	**$ (7)**	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD **May 2016**
($ Millions)

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	67	69	(2)
Demand	46	47	(1)
Base Service Charge	14	14	(0)
Rate Mechanisms	16	16	(0)
Other Rev/Cost of Sales	(0)	(0)	0
Other Margin Items	(3)	(2)	(1)
	139	143	(4)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	29	29	(0)
Demand	15	15	0
Base Service Charge	6	6	(0)
Rate Mechanisms	8	9	(1)
Other Rev/Cost of Sales	0	(0)	0
Other Margin Items	(2)	(2)	(0)
	56	57	(1)

KU Electric Margin

	Actual	Budget	Variance
Base Energy	38	40	(2)
Demand	31	32	(1)
Base Service Charge	8	8	0
Rate Mechanisms	8	8	0
Other Rev/Cost of Sales	(0)	(0)	(0)
Other Margin Items	(0)	(0)	(0)
	83	86	(3)

LKE Base Energy Price/Vol Variance

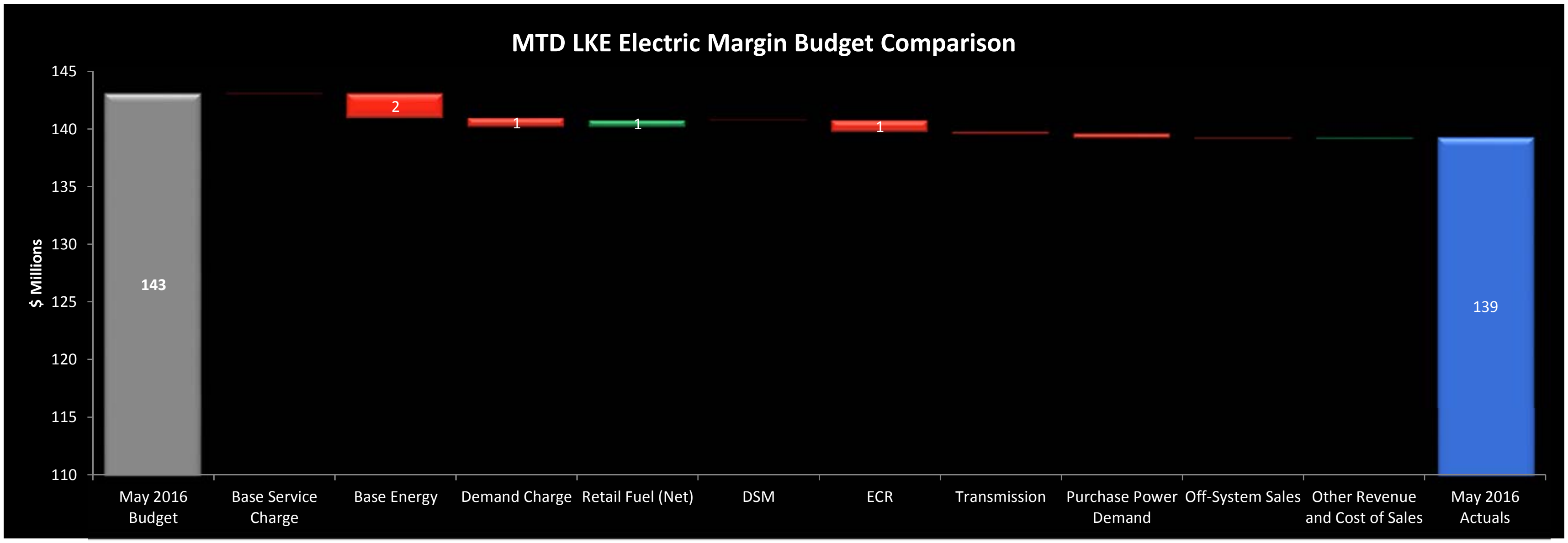
	Volume	Price	Total Variance
Residential	(0)	0	0
Commercial	(1)	(0)	(1)
Industrial	(1)	0	(1)
Public Authority	(0)	0	(0)
Street Lights	(0)	0	0
Municipals	(0)	(0)	(0)
Other	0	0	0
	(2)	0	(2)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	0	0	0
Commercial	(0)	(0)	(0)
Industrial	(1)	0	(0)
Public Authority	(0)	0	0
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(1)	0	(0)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(0)	0	(0)
Commercial	(1)	(0)	(1)
Industrial	(0)	0	(0)
Public Authority	(0)	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	(2)	(0)	(2)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

Electric Gross Margin Analysis - YTD

($ Millions)

May 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	380	396	(16)
Demand	219	222	(2)
Base Service Charge	68	69	(0)
Rate Mechanisms	79	78	0
Other Rev/Cost of Sales	(1)	(3)	2
Other Margin Items	(9)	(9)	(1)
	736	753	(17)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	144	146	(2)
Demand	72	70	2
Base Service Charge	28	28	(0)
Rate Mechanisms	40	39	1
Other Rev/Cost of Sales	(0)	(1)	1
Other Margin Items	(9)	(9)	(0)
	273	273	1

KU Electric Margin

	Actual	Budget	Variance
Base Energy	236	250	(14)
Demand	148	152	(4)
Base Service Charge	41	40	0
Rate Mechanisms	39	39	(1)
Other Rev/Cost of Sales	(1)	(2)	1
Other Margin Items	(0)	0	(0)
	463	480	(18)

LKE Base Energy Price/Vol Variance

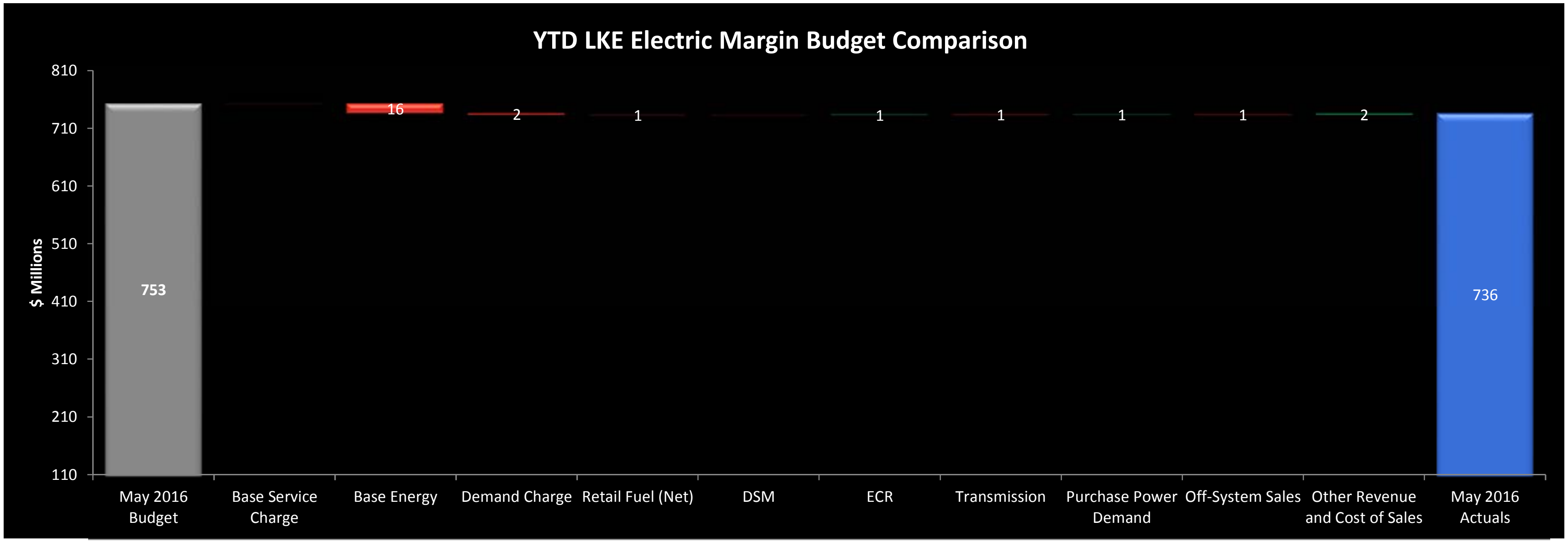
	Volume	Price	Total Variance
Residential	(13)	2	(11)
Commercial	(0)	(4)	(4)
Industrial	(2)	1	(1)
Public Authority	(0)	0	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(16)	(0)	(16)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(4)	1	(2)
Commercial	1	(2)	(0)
Industrial	(1)	0	(0)
Public Authority	0	1	1
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(3)	1	(2)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(10)	1	(8)
Commercial	(1)	(2)	(4)
Industrial	(1)	0	(0)
Public Authority	(0)	(0)	(1)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(13)	(1)	(14)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin

May 2016

($ Millions)

	MTD				YTD			
	Actual	**Budget**	**Subtotal**	**Margin Variance**	**Actual**	**Budget**	**Subtotal**	**Margin Variance**
Gas Base Service Charge	**$ 5**	**$ 5**		**0**	**$ 26**	**$ 26**		**0**
Gas Supply Costs								
Gas Supply Costs	(4)	(5)	$ 1		(64)	(87)	$ 23	
GSC Revenue	4	5	$ (1)		64	87	$ (23)	
Net Gas Supply Costs				**0**				**0**
Retail Gas (a)	**4**	**4**		**(0)**	**49**	**56**		**(7)**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**-**
DSM	**-**	**-**		**-**	**-**	**-**		**-**
GLT	**1**	**1**		**0**	**6**	**6**		**0**
WNA	**(0)**	**-**		**(0)**	**3**	**-**		**3**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**0**
Gas Margin Variance				**$ (0)**				**$ (3)**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 2	620,468	$ 2.87	$ 2	688,357	$ 2.87	($0.2)	($0.2)	($0.0)
Commercial	1	375,418	1.98	1	353,979	2.11	($0.0)	$0.0	($0.0)
Industrial	0	89,951	1.78	0	89,160	2.03	($0.0)	$0.0	($0.0)
Public Authority	0	47,633	1.84	0	59,156	1.97	($0.0)	($0.0)	($0.0)
Transportation	1	1,057,358	0.52	0	796,564	0.50	$0.2	$0.1	$0.0
Interdepartmental	0	20,134	15.16	0	109,958	2.74	$0.0	($0.2)	$0.2
Ultimate Consumer	$ 4	2,210,962	$ 1.64	$ 4	2,097,174	$ 1.78	($0.1)	($0.3)	$0.2

	YTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 31	10,937,899	$ 2.87	$ 37	12,879,548	$ 2.87	($6)	$ (6)	$ (0)
Commercial	10	4,926,165	2.11	11	5,347,170	2.14	($1)	$ (1)	$ (0)
Industrial	1	547,439	2.10	1	677,451	2.14	($0)	$ (0)	$ (0)
Public Authority	1	702,693	2.08	2	831,271	2.10	($0)	$ (0)	$ (0)
Transportation	3	6,225,657	0.53	3	5,505,109	0.48	$1	$0	$0
Interdepartmental	2	141,912	10.74	2	339,922	4.42	$0	($1)	$1
Ultimate Consumer	$ 49	23,481,765	$ 2.09	$ 56	25,580,471	$ 2.18	($7)	($8)	$1

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($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	18	17	(1)	0	(1)	(1)	1	(1)
Project Engineering	0	0	0	0	(0)	(0)	(0)	0
Transmission	2	3	0	0	0	(0)	0	0
Energy Supply and Analysis	1	1	0	0	-	0	0	0
Generation Services	1	1	0	(0)	0	1	(0)	(1)
Electric Distribution	6	7	1	(0)	1	(0)	(0)	0
Gas Distribution	3	3	(0)	0	(0)	(0)	0	0
Safety and Security	0	0	0	0	0	(0)	(0)	(0)
Customer Services	6	7	0	0	(0)	0	0	(0)
Chief Operations Officer	**37**	**38**	**1**	**1**	**0**	**1**	**1**	**(2)**
General Counsel	2	3	0	0	0	0	0	0
Human Resources	1	1	0	0	(0)	0	0	0
General Counsel & HR	**3**	**3**	**0**	**0**	**0**	**0**	**0**	**0**
Audit Services	0	0	0	0	-	(0)	0	0
Controller	1	1	0	0	-	(0)	0	0
Information Technology	4	5	1	0	(0)	0	0	0
Supply Chain	0	0	(0)	(0)	-	(0)	(0)	0
Treasurer	1	1	0	0	-	(0)	(0)	0
Chief Financial Officer	**6**	**7**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**12**	**12**	**0**	**0**	**(0)**	**0**	**(0)**	**1**
O&M Total MTD	**58**	**61**	**3**	**1**	**0**	**1**	**2**	**(1)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	87	90	2	1	(1)	0	5	(3)
Project Engineering	0	0	0	0	(0)	(0)	(0)	0
Transmission	12	12	0	0	(0)	(0)	0	0
Energy Supply and Analysis	4	4	0	0	-	(0)	0	0
Generation Services	6	6	0	0	0	(0)	(0)	0
Electric Distribution	28	30	2	(1)	3	(1)	(0)	1
Gas Distribution	14	14	(1)	0	(0)	0	(0)	(0)
Safety and Security	2	2	0	0	(0)	0	0	(0)
Customer Services	34	35	1	1	0	0	0	(0)
Chief Operations Officer	**187**	**192**	**6**	**2**	**2**	**(0)**	**5**	**(2)**
General Counsel	14	14	1	0	0	(0)	0	0
Human Resources	3	3	0	(0)	(0)	0	0	0
General Counsel & HR	**17**	**17**	**1**	**0**	**0**	**(0)**	**0**	**0**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	4	4	0	(0)	-	0	0	0
Information Technology	23	25	2	1	(0)	0	0	0
Supply Chain	2	2	(0)	(0)	(0)	(0)	0	0
Treasurer	4	5	0	(0)	-	(0)	(0)	1
Chief Financial Officer	**34**	**36**	**2**	**1**	**(0)**	**0**	**0**	**1**
Corporate	**64**	**63**	**(2)**	**(2)**	**(1)**	**1**	**(0)**	**1**
O&M Total YTD	**301**	**308**	**7**	**1**	**0**	**1**	**5**	**0**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	205	206	0	2	(1)	(0)	1	(1)
Project Engineering	1	1	0	0	-	(0)	(0)	0
Transmission	30	30	(0)	(0)	(0)	(0)	(0)	1
Energy Supply and Analysis	9	9	0	0	-	(0)	0	0
Generation Services	16	15	(0)	(0)	(0)	(1)	(0)	2
Electric Distribution	72	73	1	(0)	(3)	3	0	1
Gas Distribution	34	34	0	(0)	0	(0)	0	0
Safety and Security	5	5	(0)	(0)	(0)	(0)	0	(0)
Customer Services	86	87	0	0	(0)	0	(0)	0
Chief Operations Officer	**457**	**459**	**2**	**2**	**(4)**	**1**	**1**	**2**
General Counsel	35	35	0	0	(0)	0	(0)	0
Human Resources	7	7	0	(0)	-	0	0	0
General Counsel & HR	**42**	**42**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Audit Services	2	2	(0)	0	-	(0)	0	(0)
Controller	10	10	(0)	(0)	-	0	(0)	0
Information Technology	60	60	0	1	(0)	(0)	0	(1)
Supply Chain	4	4	(0)	(0)	(0)	0	(0)	(0)
Treasurer	11	11	0	(0)	-	(0)	(0)	1
Chief Financial Officer	**86**	**86**	**0**	**(0)**	**(0)**	**(0)**	**0**	**0**
Corporate	**141**	**144**	**3**	**(0)**	**(0)**	**0**	**(0)**	**3**
O&M Total Full Year	**726**	**731**	**5**	**1**	**(4)**	**2**	**1**	**5**

Note: Schedules may not sum due to rounding.

Financing Activities — May 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.8	$ (0.0)	$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	0.0	923.8	923.8	(0.0)
Ave Bal	**$ 923.8**	**$ 923.8**	**$ (0.0)**	**$ 923.8**	**$ 923.8**	**$ (0.0)**
Interest Exp	**$ 5.0**	**$ 5.8**	**$ 0.8**	**$ 13.1**	**$ 13.9**	**$ 0.8**
Rate	**1.29%**	**1.48%**	**0.20%**	**1.40%**	**1.48%**	**0.08%**
FMB/Sr Nts						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 75.0**	**$ 73.0**	**$ (2.0)**	**$ 177.3**	**$ 175.3**	**$ (2.0)**
Rate	**4.22%**	**4.11%**	**-0.11%**	**4.14%**	**4.10%**	**-0.05%**
Short-term Debt						
Beg Bal	$ 318.9	$ 260.9	$ (58.0)	$ 451.8	$ 347.7	$ (104.1)
End Bal	287.0	317.2	30.2	497.3	347.7	(149.6)
Ave Bal	**$ 302.9**	**$ 289.1**	**$ (13.9)**	**$ 474.5**	**$ 347.7**	**$ (126.9)**
Interest Exp	**$ 1.6**	**$ 2.0**	**$ 0.4**	**$ 5.2**	**$ 4.8**	**$ (0.4)**
Rate	**1.22%**	**1.64%**	**0.42%**	**1.08%**	**1.35%**	**0.27%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (45.4)	$ 0.9	$ (42.2)	$ (39.6)	$ 2.6
End Bal	(44.7)	(44.7)	0.0	(40.7)	(39.6)	1.1
Ave Bal	**$ (45.5)**	**$ (45.1)**	**$ 0.5**	**$ (41.5)**	**$ (39.6)**	**$ 1.9**
Total End Bal	**$ 5,376.1**	**$ 5,406.4**	**$ 30.2**	**$ 5,590.4**	**$ 5,441.9**	**$ (148.5)**
Total Average Bal	**$ 5,391.3**	**$ 5,377.8**	**$ (13.4)**	**$ 5,566.9**	**$ 5,441.9**	**$ (125.0)**
Total Expense Excl I/C [(1)]	**$ 87.7**	**$ 90.4**	**$ 2.7**	**$ 213.9**	**$ 217.2**	**$ 3.3**
Rate	**3.82%**	**3.95%**	**0.13%**	**3.75%**	**3.90%**	**0.15%**

(1) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[(2)]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 166		$ 134
LG&E	500	87		413
KU	598	34	$ 198	366
TOTAL	$ 1,398	$ 287	$ 198	$ 913

(2) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	17%	17%	27%	26%	26%	24%
CFO pre-WC + Interest / Interest	5.7	5.6	8.3	8.0	7.7	7.4
CFO pre-WC - Dividends / Debt	16%	15%	27%	24%	18%	16%
Debt to Capitalization[2]	48%	48%	38%	39%	39%	39%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — May 2016

($ Millions)

	5/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 14	$ 15	$ (1)	
Accounts Receivable (Trade)	336	359	(23)	
Inventory	283	255	28	Higher actual due to lower than expected usage and higher than budgeted inventory levels.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	23	58	(35)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	50	45	6	
Total Current Assets	707	731	(25)	
Property, Plant, and Equipment	11,512	11,617	(106)	
Intangible Assets	112	105	7	
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	754	738	16	
Goodwill	997	997	-	
Other Long-term Assets	76	79	(3)	
Total Assets	**$ 14,159**	**$ 14,268**	**$ (110)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 244	$ 262	$ (18)	
Dividends Payable to Affiliated Companies	85	-	85	
Customer Deposits	54	52	2	
Derivative Liability	6	5	1	
Accrued Taxes	27	98	(71)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. $27m was reclassed between current and deferred taxes and $6m was moved from tax receivable to tax payable in May 2016.
Regulatory Liabilities Current	29	31	(2)	
Other Current Liabilities	178	179	(1)	
Total Current Liabilities	622	627	(5)	
Debt - Affiliated Company	566	428	138	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016.
Debt [(1)]	4,810	4,978	(168)	
Total Debt	5,376	5,406	(30)	
Deferred Tax Liabilities	1,559	1,523	37	
Investment Tax Credit	126	126	0	
Accum Provision for Pension & Related Benefits	271	267	4	
Asset Retirement Obligation	469	494	(25)	
Regulatory Liabilities Non Current	914	893	21	
Derivative Liability	46	42	4	
Other Liabilities	208	205	3	
Total Deferred Credits and Other Liabilities	3,594	3,551	43	
Equity	4,567	4,684	(117)	
Total Liabilities and Equity	**$ 14,159**	**$ 14,268**	**$ (110)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

May 2016

($ Millions)

	5/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 6	$ 5	$ 1	
Accounts Receivable (Trade)	142	154	(11)	
Inventory	120	100	20	Higher actual due to lower than expected usage and higher than budgeted inventory levels.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	10	22	(12)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	40	32	8	
Total Current Assets	318	313	6	
Property, Plant, and Equipment	4,880	4,947	(67)	
Intangible Assets	6	2	4	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	429	419	10	
Goodwill	-	-	-	
Other Long-term Assets	17	18	(2)	
Total Assets	**$ 5,650**	**$ 5,700**	**$ (50)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 176	$ 180	$ (4)	
Dividends Payable to Affiliated Companies	36	36	0	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	16	50	(34)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. In May 2016, $12m was reclassed from current to deferred.
Regulatory Liabilities Current	8	13	(5)	
Other Current Liabilities	75	65	10	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Total Current Liabilities	343	375	(32)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,728	1,787	(59)	
Total Debt	1,728	1,787	(59)	
Deferred Tax Liabilities	878	860	18	
Investment Tax Credit	34	34	(0)	
Accum Provision for Pension & Related Benefits	43	42	2	
Asset Retirement Obligation	134	152	(18)	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Regulatory Liabilities Non Current	366	356	10	
Derivative Liability	46	42	4	
Other Liabilities	92	91	1	
Total Deferred Credits and Other Liabilities	1,593	1,577	16	
Equity	1,986	1,961	25	
Total Liabilities and Equity	**$ 5,650**	**$ 5,700**	**$ (50)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

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Balance Sheet - KU

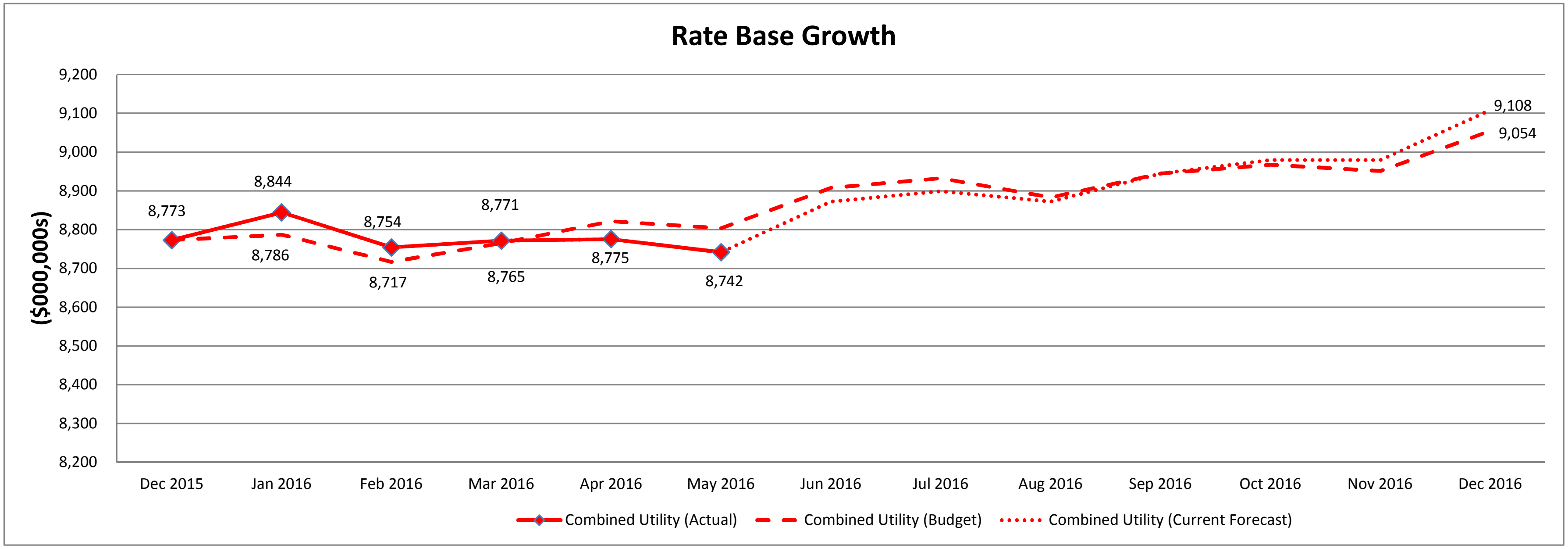
May 2016

($ Millions)

	5/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 7	$ 5	$ 2	
Accounts Receivable (Trade)	193	205	(12)	
Inventory	163	155	8	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	13	36	(23)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	23	23	(1)	
Total Current Assets	399	424	(25)	
Property, Plant, and Equipment	6,625	6,663	(39)	
Intangible Assets	13	10	3	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	319	313	6	
Goodwill	-	-	-	
Other Long-term Assets	51	51	(0)	
Total Assets	**$ 7,407**	**$ 7,462**	**$ (55)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 110	$ 126	$ (16)	Primarily due to decrease in project engineering accruals and timing of other payables.
Dividends Payable to Affiliated Companies	49	51	(2)	
Customer Deposits	28	26	1	
Derivative Liability	-	-	-	
Accrued Taxes	14	53	(39)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. In May 2016, $19m was reclassed from current to deferred tax liability and $6m was reclasssed from receivable to payable.
Regulatory Liabilities Current	21	17	3	
Other Current Liabilities	67	71	(4)	
Total Current Liabilities	288	345	(56)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,357	2,391	(34)	
Total Debt	2,357	2,391	(34)	
Deferred Tax Liabilities	1,110	1,087	23	
Investment Tax Credit	92	92	0	
Accum Provision for Pension & Related Benefits	38	38	1	
Asset Retirement Obligation	336	342	(7)	
Regulatory Liabilities Non Current	455	444	11	
Derivative Liability	-	-	-	
Other Liabilities	60	59	1	
Total Deferred Credits and Other Liabilities	2,091	2,063	29	
Equity	2,670	2,664	6	
Total Liabilities and Equity	**$ 7,407**	**$ 7,462**	**$ (55)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.



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Performance Report

June 2016

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Kentucky Regulated Dashboard — June 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.56	1.17	0.97	1.06	1.38	1.22
Employee lost-time incidents	1	0	2	2	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,034	3,072	16,410	17,281	34,093	34,964
Utility EFOR	13.1%	5.7%	6.4%	5.7%	N/A	5.7%
Utility EAF	85.4%	82.2%	82.4%	82.2%	N/A	82.3%
Steam Fleet Commercial Availability	90.8%	92.8%	93.2%	92.8%	N/A	92.8%
Combined SAIFI	0.15	0.12	0.55	0.53	N/A	1.03
Combined SAIDI (minutes)	14.70	12.83	50.70	48.37	N/A	94.09
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	998	909	5,175	5,334	10,688	10,847
Commercial	717	710	3,784	3,780	7,797	7,793
Industrial	820	926	4,651	4,963	9,779	10,089
Municipals	172	168	914	929	1,871	1,886
Other	252	256	1,355	1,381	2,771	2,798
Off-System Sales	13	7	75	281	114	322
Total	2,972	2,976	15,954	16,668	33,020	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.63%			
Commercial			1.13%			
Industrial			-4.22%			
Municipal			0.58%			
Other			0.01%			
Total			-1.83%			

	Current Month		YTD		Full Year	
Margins ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$166	$162	$902	$915	$1,845	$1,870
Gas Margins	9	9	95	98	171	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$0	$0	$14	$7	$16	$9
ECR	21	28	117	213	337	404
Generation	15	14	60	71	125	117
Transmission	8	6	36	43	89	90
Electric Distribution	13	15	76	81	170	169
Gas Distribution	8	9	38	41	89	86
Customer Services	1	2	8	10	21	20
IT and Other	4	5	27	30	61	59
Total	$70	$80	$375	$495	$908	$955
O&M ($ millions)[3]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$36	$38	$222	$230	$447	$459
General Counsel & HR	4	4	19	19	38	39
Finance, IT, & Supply Chain	7	8	42	45	87	90
Burdens & Other Charges	10	11	74	74	145	144
Total	$56	$60	$358	$368	$717	$732
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,487	3,583	3,487	3,583	3,566	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	3	0	12	N/A	16
NERC Possible Violations[4]	0	3	1	5	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[5]	9.6%	9.8%	9.8%

Variance Explanations

• Current month higher EFOR primarily due to generator bearing vibration and rotor winding issues on Trimble County Unit 2.

• YTD lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $15 million and $3 million lower gas margins. This was partially offset by $2 million lower cost of production.

• YTD lower O&M primarily due to timing of plant maintenance, storm restoration, vegetation management and consulting services along with labor and burden savings.

• YTD capital expenditures were lower, primarily due to the timing of ECR spending on Environmental Air projects at Mill Creek, permitting delays related to CCR projects at Trimble County and various other generation projects.

Major Developments

• Republican Governor Matt Bevin appointed Michael J. Schmitt, a Paintsville attorney, to serve as Chairman of the KPSC. Schmitt has represented a number of clients in coal, oil and gas litigation over a period of 45 years. Schmitt replaces James W. Gardner, whose reappointment was not confirmed by the Senate in the 2016 General Assembly. Schmitt assumes the remainder of Gardner's term, which will expire July 1, 2019. Bevin also named Robert J. Cicero as Vice Chair. Cicero was appointed to Commissioner in April 2016. Both appointments are subject to Senate confirmation.

• There was significant storm activity which passed through LKE's service territories during June. The events affected about 45,000 customers, and produced 175 downed lines and 12 broken poles. Restoration efforts were performed without injury and completed within 24 hours.

• LG&E and KU won two awards from the Kentuckiana chapter of the American Heart Association. The Company won a Gold Award and the Fit-Friendly Worksite Community Innovation Award for the expanding wellness participation at Cane Run Generating Station.

Significant Future Events

• An Order from the KPSC regarding the ECR filing is expected around the end of July.

(1) Full year forecast amount shown represents target.

(2) Due to timing, full year forecasted amount will not tie to the amount reported in the Performance and Key Events Report.

(3) Net of cost recovery mechanisms.

(4) The possible violation issues are believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (Month) - LKE Consolidated — June 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 256	$ 263	$ (7)	Due to lower FAC revenue from lower fuel costs (see below) and industrial (primarily [redacted] revenues partially offset by higher residential revenue.
Gas Revenues	12	13	(1)	
Total Revenues	268	276	(7)	
Cost of Sales:				
Fuel Electric Costs	73	80	7	Primarily due to lower commodity costs.
Gas Supply Expenses	3	4	1	
Purchased Power	4	5	1	
Other Electric Cost	13	16	3	
Total Cost of Sales	93	104	11	
Gross Margin:				
Electric Margin	166	162	4	
Gas Margin	9	9	(0)	
Total Gross Margin	175	171	4	
Operating Expenses:				
O&M	56	60	4	
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	90	95	5	
Other income (expense)	(1)	(1)	0	
EBIT	85	76	9	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	67	58	9	
Income Tax Expense	26	22	(4)	
Net Income (loss) from ongoing operations	**41**	**36**	**$ 5**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 41	$ 36	$ 5	
KY Regulated Financing Costs	(3)	(2)	(0)	
KY Regulated Net Income	$ 39	$ 33	$ 5	
Earnings Per Share - Ongoing	$ 0.06	$ 0.05	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — June 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,383	$ 1,474	$ (91)	Due to lower volumes driven by unfavorable weather, FAC revenue from lower fuel costs (see below) and industrial volumes.
Gas Revenues	166	194	(28)	See Gas Supply Expenses explanation below.
Total Revenues	1,549	1,669	(120)	
Cost of Sales:				
Fuel Electric Costs	382	446	64	Primarily due to decreased generation as a result of mild weather and to lower commodity costs.
Gas Supply Expenses	72	96	25	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	28	28	0	
Other Electric Cost	72	85	14	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	553	656	103	
Gross Margin:				
Electric Margin	902	915	(13)	Lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $15 million. This was partially offset by $2 million lower cost of production.
Gas Margin	95	98	(3)	
Total Gross Margin	996	1,013	(17)	
Operating Expenses:				
O&M	358	368	10	Lower O&M primarily due to timing of plant maintenance, storm restoration, vegetation management and consulting services along with labor and burden savings.
Depreciation & Amortization	174	178	5	
Taxes, Other than Income	28	28	0	
Total Operating Expenses	560	574	15	
Other income (expense)	(5)	(4)	(0)	
EBIT	432	434	(2)	
Interest Expense	105	109	3	
Income from Ongoing Operations before income taxes	327	326	1	
Income Tax Expense	123	124	1	
Net Income (loss) from ongoing operations	**203**	**202**	**$ 2**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 203	$ 201	$ 2	
KY Regulated Financing Costs	(15)	$ (15)	(0)	
KY Regulated Net Income	$ 188	$ 186	$ 2	
Earnings Per Share - Ongoing	$ 0.28	$ 0.27	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

June 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 544	$ 568	$ (24)	Primarily due to lower off system sales and FAC revenue which were offset by lower related fuel costs below.
Gas Revenues	166	194	(28)	See Gas Supply Expenses explanation below.
Total Revenues	710	763	(52)	
Cost of Sales:				
Fuel Electric Costs	149	167	18	Primarily due to decreased generation as a result of mild weather, lower commodity costs and lower off system sales.
Gas Supply Expenses	72	96	25	Due to lower gas usage (mild weather) and prices
Purchased Power	25	29	3	
Other Electric Cost	27	34	6	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	273	325	52	
Gross Margin:				
Electric Margin	342	339	3	
Gas Margin	95	98	(3)	
Total Gross Margin	437	437	(0)	
Operating Expenses:				
O&M	160	166	6	Lower O&M primarily due to timing of plant maintenance and labor and burden savings.
Depreciation & Amortization	71	73	2	
Taxes, Other than Income	14	14	(0)	
Total Operating Expenses	245	252	7	
Other income (expense)	(3)	(2)	(1)	
EBIT	190	183	6	
Interest Expense	35	35	1	
Income from Ongoing Operations before income taxes	155	148	7	
Income Tax Expense	59	57	(3)	
Net Income (loss) from ongoing operations	**96**	**91**	**$ 4**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU | **June 2016**

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 860	$ 941	$ (80)	Due to lower volumes driven by unfavorable weather and by the loss of [redacted]) as a customer.
Gas Revenues	-	-	-	
Total Revenues	860	941	(80)	
Cost of Sales:				
Fuel Electric Costs	233	283	50	Primarily due to decreased generation as a result of mild weather and to lower commodity costs.
Gas Supply Expenses	-	-	-	
Purchased Power	23	30	6	Lower purchased power due to mild weather.
Other Electric Cost	44	52	8	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	301	365	64	
Gross Margin:				
Electric Margin	559	576	(16)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	559	576	(16)	
Operating Expenses:				
O&M	184	190	6	Lower O&M primarily due to lower storm restoration, vegetation management and consulting services along with labor and burden savings.
Depreciation & Amortization	103	106	2	
Taxes, Other than Income	14	14	0	
Total Operating Expenses	301	310	9	
Other income (expense)	(2)	(2)	1	
EBIT	257	263	(7)	
Interest Expense	47	49	2	
Income from Ongoing Operations before income taxes	209	215	(5)	
Income Tax Expense	80	82	2	Lower income taxes primarily due to lower pre-tax income.
Net Income (loss) from ongoing operations	**130**	**133**	**$ (3)**	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Budget - LKE Consolidated				June 2016
($ Millions)				
	Full Year			
	Q2 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,901	$ 3,011	$ (110)	Due to lower volumes driven by unfavorable weather, along with lower fuel costs as shown below. In addition, an updated load forecast with lower volumes was included for the remainder of the year.
Gas Revenues	301	330	(29)	See Gas Supply Expenses explanation below.
Total Revenues	3,203	3,342	(139)	
Cost of Sales:				
Fuel Electric Costs	837	901	65	Primarily due to decreased generation as a result of mild weather and to lower commodity costs.
Gas Supply Expenses	130	155	25	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	57	58	0	
Other Electric Cost	162	182	20	Due to lower ECR expense (using less PAC and NALCO), mild weather and scrubber reactant expense.
Total Cost of Sales	1,187	1,296	110	
Gross Margin:				
Electric Margin	1,845	1,870	(25)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	171	175	(5)	See Gas Supply Expenses explanation above.
Total Gross Margin	2,016	2,045	(30)	
Operating Expenses:				
O&M	717	731	14	Due to lower labor and burden costs, maintenance & outage savings, lower storm restoration & vegetation management, A&G expenses and consulting support.
Depreciation & Amortization	349	359	9	Due to increased auto-retirements not captured in the budget, along with revised in-service dates and final spend on completed projects.
Taxes, Other than Income	56	56	0	
Total Operating Expenses	1,122	1,146	24	
Other income (expense)	(8)	(7)	(1)	
EBIT	886	892	(6)	
Interest Expense	213	217	4.12	
Income from Ongoing Operations before income taxes	673	675	(2)	
Income Tax Expense	255	257	2	
Net Income (loss) from ongoing operations	**417**	**417**	**$ 0**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 417	$ 417	$ 0	
KY Regulated Financing Costs	(30)	$ (30)	(0)	
KY Regulated Net Income	$ 387	$ 387	$ 0	
Earnings Per Share - Ongoing	$ 0.57	$ 0.57	$ (0.00)	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD
($ Millions)

June 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	88	84	4
Demand	49	50	(1)
Base Service Charge	14	14	0
Rate Mechanisms	16	17	(1)
Other Rev/Cost of Sales	(1)	(1)	(0)
Other Margin Items	(0)	(2)	2
	166	162	4

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	40	38	2
Demand	16	16	0
Base Service Charge	6	6	(0)
Rate Mechanisms	8	9	(1)
Other Rev/Cost of Sales	(0)	(0)	0
Other Margin Items	(1)	(2)	1
	69	67	3

KU Electric Margin

	Actual	Budget	Variance
Base Energy	48	46	2
Demand	33	33	(1)
Base Service Charge	8	8	0
Rate Mechanisms	7	8	(0)
Other Rev/Cost of Sales	(1)	(0)	(0)
Other Margin Items	1	0	0
	97	95	1

LKE Base Energy Price/Vol Variance

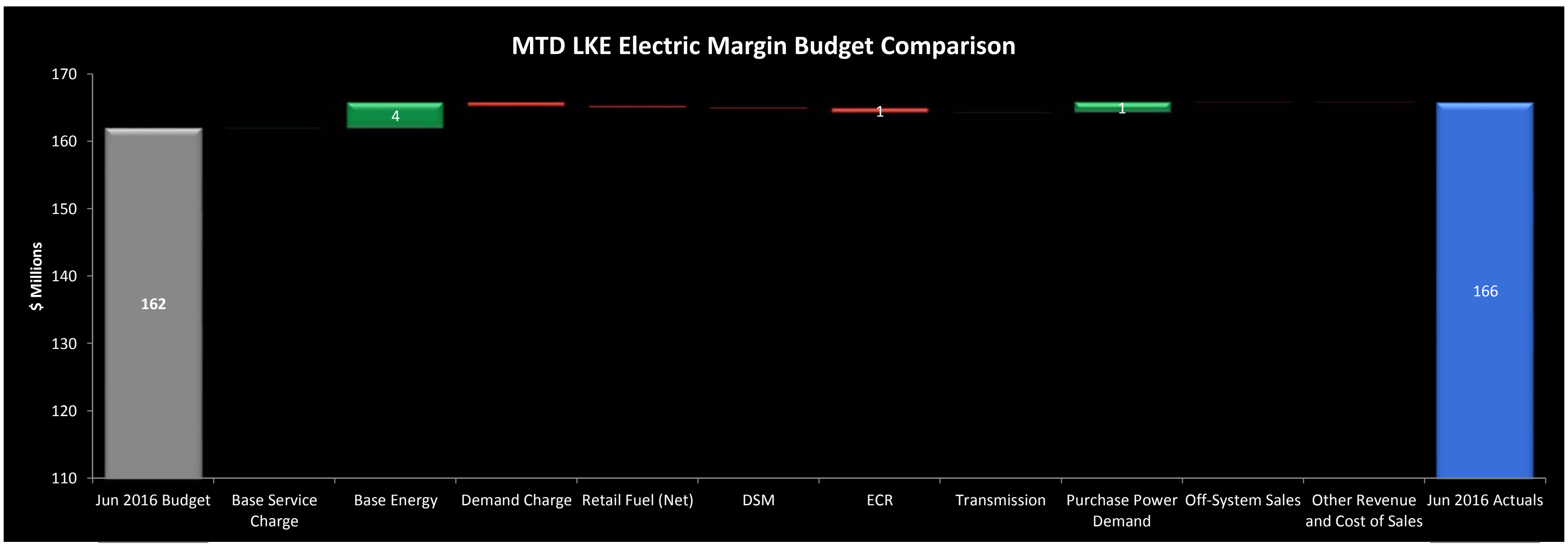
	Volume	Price	Total Variance
Residential	5	1	5
Commercial	0	(1)	(0)
Industrial	(1)	0	(1)
Public Authority	(0)	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	0	(0)	(0)
Other	0	0	0
	4	(0)	4

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	2	0	3
Commercial	0	(1)	(0)
Industrial	(0)	0	(0)
Public Authority	0	(0)	(0)
Street Lights	0	(0)	(0)
Municipals	0	0	0
Other	0	0	0
	2	(0)	2

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	2	0	3
Commercial	(0)	0	(0)
Industrial	(0)	0	(0)
Public Authority	(0)	0	(0)
Street Lights	(0)	0	(0)
Municipals	0	(0)	(0)
Other	0	0	0
	1	0	2



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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($ Millions)

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	468	481	(13)
Demand	268	271	(3)
Base Service Charge	82	82	(0)
Rate Mechanisms	94	95	(1)
Other Rev/Cost of Sales	(1)	(4)	2
Other Margin Items	(10)	(10)	1
	902	915	(13)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	183	184	(1)
Demand	88	86	2
Base Service Charge	33	34	(0)
Rate Mechanisms	48	48	0
Other Rev/Cost of Sales	(0)	(1)	1
Other Margin Items	(10)	(11)	1
	342	339	3

KU Electric Margin

	Actual	Budget	Variance
Base Energy	285	297	(12)
Demand	181	185	(5)
Base Service Charge	49	49	0
Rate Mechanisms	46	47	(1)
Other Rev/Cost of Sales	(1)	(3)	1
Other Margin Items	0	0	(0)
	559	576	(16)

LKE Base Energy Price/Vol Variance

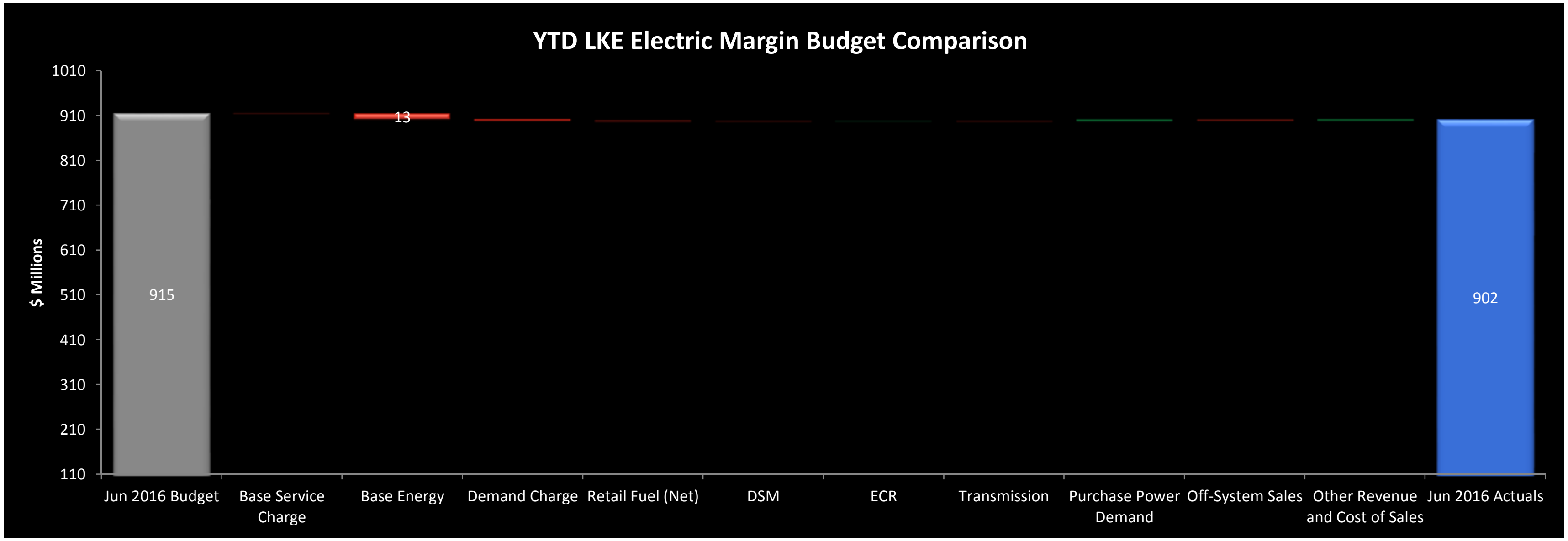
	Volume	Price	Total Variance
Residential	(9)	3	(6)
Commercial	0	(4)	(4)
Industrial	(3)	1	(1)
Public Authority	(0)	0	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(13)	(0)	(13)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(1)	1	0
Commercial	2	(2)	(1)
Industrial	(1)	1	(1)
Public Authority	0	1	1
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(1)	0	(1)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(7)	2	(6)
Commercial	(2)	(2)	(4)
Industrial	(1)	1	(1)
Public Authority	(0)	(0)	(1)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(12)	(0)	(12)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

Gas Gross Margin — June 2016

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**0**	**$ 31**	**$ 31**		**0**
Gas Supply Costs								
Gas Supply Costs	(2)	(3)	$ 0		(66)	(90)	$ 24	
GSC Revenue	2	3	$ (0)		67	90	$ (23)	
Net Gas Supply Costs				**0**				**0**
Retail Gas (a)	**3**	**3**		**(0)**	**52**	**58**		**(7)**
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**-**
DSM	**-**	**-**		**-**	**-**	**-**		**-**
GLT	**1**	**1**		**0**	**7**	**7**		**0**
WNA	**(0)**	**-**		**(0)**	**3**	**-**		**3**
Other Margin	**0**	**0**		**(0)**	**1**	**1**		**0**
Gas Margin Variance				**$ 0**				**$ (3)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 1	361,934	$ 2.86	$ 1	374,129	$ 2.87	($0.0)	($0.0)	($0.0)
Commercial	1	261,515	1.95	1	266,285	2.10	($0.0)	($0.0)	($0.0)
Industrial	0	78,092	1.68	0	85,366	2.07	($0.0)	($0.0)	($0.0)
Public Authority	0	27,533	1.76	0	46,726	1.93	($0.0)	($0.0)	($0.0)
Transportation	0	1,072,321	0.44	0	794,722	0.54	$0.0	$0.1	($0.1)
Interdepartmental	0	26,813	11.79	0	181,041	1.69	$0.0	($0.3)	$0.3
Ultimate Consumer	$ 3	1,828,208	$ 1.38	$ 3	1,748,269	$ 1.51	($0.1)	($0.2)	$0.1

YTD

	Actual Revenue $mil	Actual Volume (Mcf)	Actual Price ($/Mcf)	Budget Revenue $mil	Budget Volume (Mcf)	Budget Price ($/Mcf)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 32	11,299,833	$ 2.87	$ 38	13,253,677	$ 2.87	($6)	$ (6)	$ (0)
Commercial	11	5,187,680	2.10	12	5,613,454	2.14	($1)	$ (1)	$ (0)
Industrial	1	625,531	2.04	2	762,817	2.13	($0)	$ (0)	$ (0)
Public Authority	2	730,226	2.06	2	877,997	2.10	($0)	$ (0)	$ (0)
Transportation	4	7,297,978	0.51	3	6,299,831	0.49	$1	$0	$0
Interdepartmental	2	168,725	10.91	2	520,963	3.47	$0	($1)	$1
Ultimate Consumer	$ 52	25,309,973	$ 2.04	$ 58	27,328,740	$ 2.14	($7)	($8)	$1

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	16	2	1	(1)	1	1	(0)
Project Engineering	0	0	0	0	0	(0)	(0)	0
Transmission	4	3	(1)	(0)	(0)	0	0	(0)
Energy Supply and Analysis	1	1	0	(0)	-	0	0	0
Generation Services	1	1	0	(0)	(0)	0	(0)	0
Electric Distribution	7	7	(0)	(0)	(0)	(0)	0	0
Gas Distribution	3	3	(0)	0	(0)	(0)	0	0
Safety and Technical Training	1	0	(0)	(0)	(0)	(0)	(0)	0
Customer Services	6	7	1	0	0	0	0	1
Chief Operations Officer	**36**	**38**	**2**	**(0)**	**(1)**	**2**	**1**	**0**
General Counsel	3	3	(0)	(0)	(0)	0	(0)	0
Human Resources	1	1	0	0	-	0	0	0
General Counsel & HR	**4**	**4**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**0**
Audit Services	0	0	0	(0)	-	(0)	0	0
Controller	1	1	0	(0)	-	0	0	0
Information Technology	5	5	1	0	0	0	0	0
Supply Chain	0	0	(0)	(0)	(0)	(0)	0	(0)
Treasurer	1	1	0	(0)	-	(0)	(0)	0
State Regulation and Rates	0	0	0	0	-	0	(0)	0
Chief Financial Officer	**7**	**8**	**1**	**0**	**0**	**0**	**0**	**0**
Corporate	**10**	**11**	**1**	**1**	**(0)**	**0**	**(0)**	**0**
O&M Total MTD	**56**	**60**	**4**	**1**	**(1)**	**2**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	101	105	4	2	(1)	2	6	(3)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	15	15	(0)	(0)	(0)	0	0	0
Energy Supply and Analysis	4	5	0	0	-	(0)	0	0
Generation Services	7	7	0	0	(0)	(0)	(0)	0
Electric Distribution	35	37	2	(1)	3	(1)	0	1
Gas Distribution	17	16	(1)	0	(1)	(0)	(0)	(0)
Safety and Technical Training	2	3	0	0	(0)	0	0	(0)
Customer Services	40	42	2	1	0	0	0	1
Chief Operations Officer	**222**	**230**	**8**	**2**	**1**	**1**	**6**	**(1)**
General Counsel	15	16	0	0	0	(0)	0	0
Human Resources	3	4	0	(0)	(0)	0	0	0
General Counsel & HR	**19**	**19**	**1**	**0**	**0**	**(0)**	**0**	**0**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	5	5	0	(0)	-	0	0	0
Information Technology	28	30	2	1	(0)	1	0	0
Supply Chain	2	2	(0)	(0)	(0)	(0)	0	0
Treasurer	5	6	0	(0)	-	(0)	(0)	1
State Regulation and Rates	2	2	(0)	(0)	-	0	(0)	0
Chief Financial Officer	**42**	**45**	**3**	**1**	**(0)**	**0**	**0**	**2**
Corporate	**74**	**74**	**(0)**	**(1)**	**(1)**	**1**	**(0)**	**1**
O&M Total YTD	**358**	**368**	**11**	**2**	**(1)**	**3**	**6**	**2**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	201	206	4	2	(2)	2	3	(1)
Project Engineering	0	1	0	0	-	(0)	(0)	0
Transmission	30	30	1	0	(1)	0	0	0
Energy Supply and Analysis	9	9	0	0	-	(0)	0	0
Generation Services	15	15	0	0	(0)	(0)	(0)	1
Electric Distribution	70	73	3	(0)	(2)	4	0	1
Gas Distribution	33	34	1	0	0	0	0	0
Safety and Technical Training	5	5	0	(0)	(0)	0	0	(0)
Customer Services	84	87	2	2	(0)	0	(0)	0
Chief Operations Officer	**447**	**459**	**12**	**5**	**(5)**	**7**	**3**	**2**
General Counsel	31	32	1	0	(0)	0	0	0
Human Resources	7	7	0	0	(0)	0	0	0
General Counsel & HR	**38**	**39**	**1**	**0**	**(0)**	**0**	**0**	**0**
Audit Services	2	2	0	0	-	(0)	0	0
Controller	10	10	0	(0)	-	0	0	0
Information Technology	58	60	2	2	(0)	0	0	0
Supply Chain	4	4	(0)	(0)	(0)	0	(0)	(0)
Treasurer	11	11	0	(0)	-	(0)	(0)	1
State Regulation and Rates	3	3	0	0	-	0	(0)	0
Chief Financial Officer	**87**	**90**	**2**	**1**	**(0)**	**(0)**	**0**	**2**
Corporate	**145**	**144**	**(1)**	**1**	**(1)**	**1**	**(0)**	**(1)**
O&M Total Full Year	**717**	**731**	**14**	**6**	**(6)**	**8**	**3**	**2**

Note: Schedules may not sum due to rounding.

Financing Activities — June 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.8	$ (0.0)	$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	(0.0)	923.8	923.8	(0.0)
Ave Bal	**$ 923.8**	**$ 923.8**	**$ (0.0)**	**$ 923.8**	**$ 923.8**	**$ (0.0)**
Interest Exp	**$ 6.1**	**$ 6.9**	**$ 0.9**	**$ 12.5**	**$ 13.9**	**$ 1.4**
Rate	**1.30%**	**1.49%**	**0.19%**	**1.33%**	**1.48%**	**0.14%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 88.6**	**$ 88.6**	**$ 0.0**	**$ 175.3**	**$ 175.3**	**$ -**
Rate	**4.16%**	**4.16%**	**0.00%**	**4.10%**	**4.10%**	**0.00%**
Short-term Debt						
Beg Bal	$ 318.9	$ 317.2	$ (1.7)	$ 451.8	$ 347.7	$ (104.1)
End Bal	315.9	282.0	(33.9)	488.8	347.7	(141.1)
Ave Bal	**$ 317.4**	**$ 299.6**	**$ (17.8)**	**$ 470.3**	**$ 347.7**	**$ (122.6)**
Interest Exp	**$ 1.9**	**$ 2.4**	**$ 0.5**	**$ 5.0**	**$ 4.8**	**$ (0.3)**
Rate	**1.18%**	**1.59%**	**0.41%**	**1.05%**	**1.35%**	**0.29%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (44.7)	$ 1.6	$ (42.2)	$ (39.6)	$ 2.6
End Bal	(44.4)	(44.0)	0.4	(40.9)	(39.6)	1.3
Ave Bal	**$ (45.4)**	**$ (44.3)**	**$ 1.0**	**$ (41.6)**	**$ (39.6)**	**$ 2.0**
Total End Bal	**$ 5,405.4**	**$ 5,371.9**	**$ (33.5)**	**$ 5,581.8**	**$ 5,441.9**	**$ (139.9)**
Total Average Bal	**$ 5,405.9**	**$ 5,389.1**	**$ (16.8)**	**$ 5,562.6**	**$ 5,441.9**	**$ (120.7)**
Total Expense Excl I/C [1]	**$ 105.4**	**$ 108.5**	**$ 3.1**	**$ 213.1**	**$ 217.2**	**$ 4.1**
Rate	**3.83%**	**3.95%**	**0.12%**	**3.74%**	**3.90%**	**0.16%**

[1] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[2]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 176		$ 124
LG&E	500	110		390
KU	598	29	$ 198	371
TOTAL	$ 1,398	$ 315	$ 198	$ 885

[2] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	17%	17%	26%	25%	26%	25%
CFO pre-WC + Interest / Interest	5.6	5.5	7.8	7.8	7.6	7.5
CFO pre-WC - Dividends / Debt	16%	16%	25%	25%	19%	18%
Debt to Capitalization[2]	47%	47%	38%	39%	38%	39%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — June 2016

($ Millions)

	6/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 16	$ 14	$ 2	
Accounts Receivable (Trade)	367	381	(14)	
Inventory	279	257	22	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	22	61	(39)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	41	42	(1)	
Total Current Assets	725	756	(31)	
Property, Plant, and Equipment	11,541	11,654	(113)	
Intangible Assets	110	103	7	
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	767	740	27	
Goodwill	997	997	-	
Other Long-term Assets	79	80	(0)	
Total Assets	**$ 14,220**	**$ 14,331**	**$ (111)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 241	$ 268	$ (27)	Primarily due to decrease in project engineering accruals and timing of other payables.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	54	52	2	
Derivative Liability	6	5	1	
Accrued Taxes	33	76	(42)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	25	31	(6)	
Other Current Liabilities	211	194	17	
Total Current Liabilities	570	624	(54)	
Debt - Affiliated Company	576	400	176	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016 and quarterly pay off of any cash needed for operations on non quarter months. The forecast does not assume any pay off of the short term debt with affiliate.
Debt [(1)]	4,829	4,972	(143)	
Total Debt	5,405	5,372	34	
Deferred Tax Liabilities	1,580	1,581	(2)	
Investment Tax Credit	133	126	7	
Accum Provision for Pension & Related Benefits	276	268	8	
Asset Retirement Obligation	463	496	(33)	
Regulatory Liabilities Non Current	916	885	30	
Derivative Liability	50	42	8	
Other Liabilities	181	195	(14)	
Total Deferred Credits and Other Liabilities	3,598	3,594	4	
Equity	4,647	4,741	(94)	
Total Liabilities and Equity	**$ 14,220**	**$ 14,331**	**$ (111)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E — June 2016

($ Millions)

	6/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	159	164	(5)	
Inventory	122	105	17	Higher actual due to lower than expected usage and higher than budgeted inventory levels.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	8	24	(15)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	40	32	8	
Total Current Assets	337	330	7	
Property, Plant, and Equipment	4,903	4,974	(71)	
Intangible Assets	6	2	4	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	437	419	18	
Goodwill	-	-	-	
Other Long-term Assets	22	18	3	
Total Assets	**$ 5,705**	**$ 5,744**	**$ (39)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 178	$ 185	$ (7)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	20	40	(21)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	7	13	(6)	
Other Current Liabilities	83	69	14	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Total Current Liabilities	320	337	(17)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,752	1,781	(29)	
Total Debt	1,752	1,781	(29)	
Deferred Tax Liabilities	888	892	(4)	
Investment Tax Credit	37	34	3	
Accum Provision for Pension & Related Benefits	49	41	8	
Asset Retirement Obligation	136	152	(16)	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Regulatory Liabilities Non Current	367	353	14	
Derivative Liability	50	42	8	
Other Liabilities	85	89	(4)	
Total Deferred Credits and Other Liabilities	1,611	1,603	8	
Equity	2,022	2,023	(1)	
Total Liabilities and Equity	**$ 5,705**	**$ 5,744**	**$ (39)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

Balance Sheet - KU June 2016

($ Millions)

	6/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	207	216	(9)	
Inventory	157	152	5	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	13	37	(24)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	20	22	(3)	
Total Current Assets	405	433	(28)	
Property, Plant, and Equipment	6,631	6,673	(42)	
Intangible Assets	13	10	3	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	324	316	7	
Goodwill	-	-	-	
Other Long-term Assets	55	52	3	
Total Assets	**$ 7,428**	**$ 7,485**	**$ (56)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 126	$ 127	$ (2)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	28	26	1	
Derivative Liability	-	-	-	
Accrued Taxes	17	34	(17)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	17	17	(0)	
Other Current Liabilities	86	78	8	
Total Current Liabilities	273	283	(10)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,352	2,390	(38)	
Total Debt	2,352	2,390	(38)	
Deferred Tax Liabilities	1,120	1,127	(7)	
Investment Tax Credit	96	92	4	
Accum Provision for Pension & Related Benefits	39	38	1	
Asset Retirement Obligation	327	344	(17)	
Regulatory Liabilities Non Current	458	442	16	
Derivative Liability	-	-	-	
Other Liabilities	47	55	(8)	
Total Deferred Credits and Other Liabilities	2,087	2,098	(11)	
Equity	2,716	2,714	2	
Total Liabilities and Equity	**$ 7,428**	**$ 7,485**	**$ (56)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

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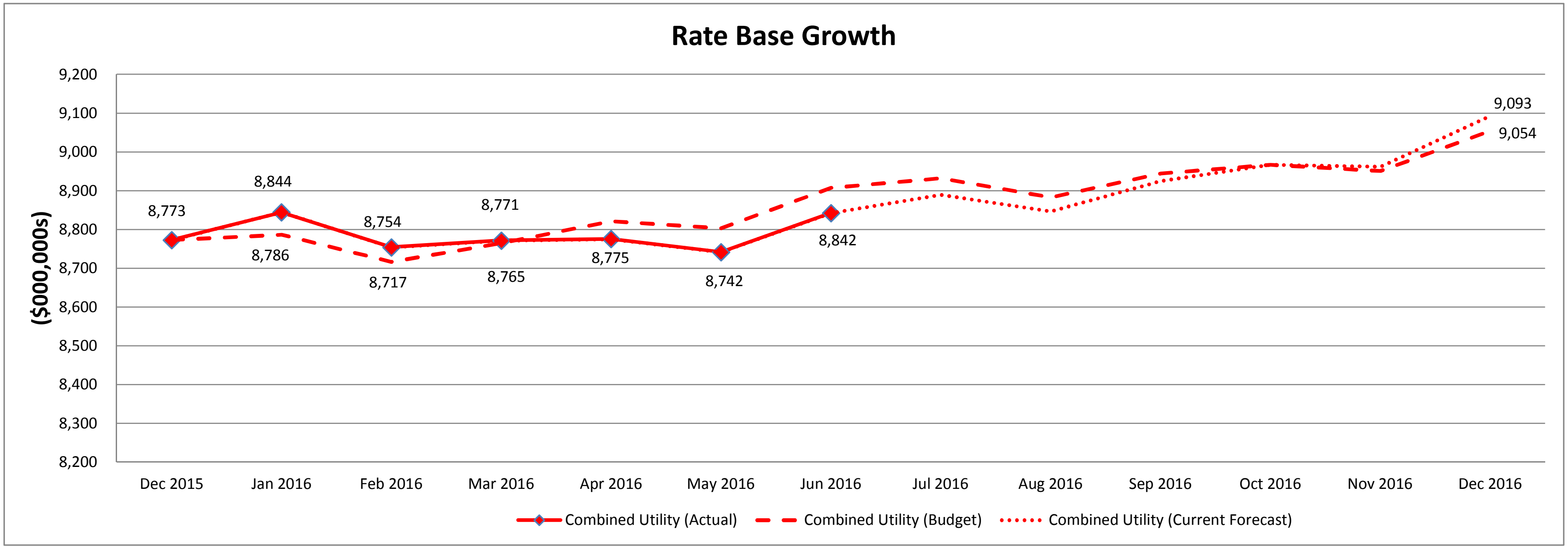

Attachment to Filing Requirement
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Blake

KU and LG&E Combined
Reconciliation of Allowed Return to
Net Income Last Rate Case Regulatory Return
and ROE from Ongoing Operations

Allowed Return (1)		10.0%	
Adjustments (net tax):			
Change in capitalization - non mechanism	0.2%		Lower capital spending
Change in ROE from average mechanism rate base growth	0.0%		Mechanisms have a real-time return
Change in weighted cost of debt	0.1%		Lower interest rates
Change in margins	-1.1%		Lower sales
Change in allowed expenses	0.5%		Lower depreciation expense
		-0.4%	
Actual Regulated ROE		9.6%	

(1) Based on the most recent base rate filings with test years ending 6/30/16 KPSC, 12/31/14 FERC, 12/31/14 VA.

Performance Report

July 2016

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Kentucky Regulated Dashboard — July 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.34	0.68	0.87	1.00	1.38	1.22
Employee lost-time incidents	0	4	2	6	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,257	3,303	19,666	20,584	34,046	34,964
Utility EFOR	10.4%	5.7%	7.1%	5.7%	N/A	5.7%
Utility EAF	88.3%	83.9%	83.2%	83.9%	N/A	82.3%
Steam Fleet Commercial Availability	91.8%	92.8%	93.0%	92.8%	N/A	92.8%
Combined SAIFI	0.14	0.11	0.69	0.64	N/A	1.03
Combined SAIDI (minutes)	15.91	11.73	66.56	60.10	N/A	94.09
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	1,137	1,112	6,312	6,446	10,651	10,847
Commercial	780	738	4,564	4,518	7,859	7,793
Industrial	778	897	5,429	5,860	9,440	10,089
Municipals	183	183	1,097	1,112	1,868	1,886
Other	258	255	1,613	1,636	2,762	2,798
Off-System Sales	27	4	102	285	136	322
Total	3,163	3,189	19,117	19,857	32,716	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.51%			
Commercial			1.24%			
Industrial			-4.76%			
Municipal			0.27%			
Other			-0.22%			
Total			-1.96%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$174	$176	$1,076	$1,091	$1,842	$1,870
Gas Margins	9	9	104	107	170	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$56	$90	$431	$585	$884	$955
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$53	$58	$411	$426	$716	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,477	3,590	3,477	3,590	3,566	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	3	3	3	15	N/A	16
NERC Possible Violations[3]	0	0	1	5	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[4]	9.7%	9.8%	9.8%

Variance Explanations

• Current month higher EFOR primarily due to generator rotor winding and ID fan vibration issues on Trimble County Unit 2 and circulating water pipe and cooling tower failure on Ghent Unit 4.

• YTD lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $16 million and $4 million lower gas margins. This was partially offset by $2 million lower production costs and purchased power.

• MTD & YTD lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management and consulting services.

• MTD capital expenditures were lower, primarily due to lower than budgeted ECR spending on CCR projects.

• YTD capital expenditures were lower, primarily due to lower level of ECR spending on Environmental Air projects at Mill Creek, permitting delays related to CCR projects at Trimble County and timing related to Transmission projects.

Major Developments

• The KPSC issued an Order in the 2016 ECR proceeding which provides for full recovery of and on all projects in the filing through the ECR mechanism. The Order is consistent with the unanimous settlement agreement with the exception of authorizing a 9.8 percent rather than 10 percent ROE. Recovery of costs under this compliance plan will commence with bills rendered on and after August 31, 2016.

• KU won a J.D. Power award for customer satisfaction, ranking first among the mid-sized utilities in the Midwest region of the 2016 Electric Utility Residential Study, while LG&E finished close behind in fourth place. Both KU and LG&E improved their positions significantly. These results reflect our employees' continued focus on the customer experience.

• LKE filed an application with the KPSC to seek approval of a community solar program called "Solar Share". Environmental impact studies are underway at the proposed site near Simpsonville, Kentucky, and Solar Energy Solutions has completed an initial design of a 500 kW solar array (expandable to 4 MW).

• Talina Rose Mathews was recently appointed Executive Director of the KPSC. Mathews most recently served as Director of Member Services and Advocacy at the Organization of MISO States Inc. She brings a strong background in energy policy and previously held positions within various state agencies and at the KPSC.

• The Kentucky Division of Waste Management issued the draft permit for the Trimble County landfill. There is a 30 day comment period until September 12, and a public hearing has been scheduled for August 30. A final permit is expected later this year.

• Business First, the weekly business journal for Greater Louisville, recently announced LG&E and KU as the winner of the Healthiest Employer Award among businesses with 1,500-4,999 employees. LKE's robust wellness program includes initiatives such as the "Healthy for Life" program, health coaching, flu shots, and health fairs. The Company received the award in 2014 and was named a finalist in 2015.

(1) Full year forecast amount shown represents target.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues are believed to be minimal risk.
(4) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — July 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 274	$ 286	$ (12)	Due to lower FAC revenue from lower fuel costs (see below) and industrial (primarily [redacted] revenues.
Gas Revenues	13	12	0	
Total Revenues	286	298	(12)	
Cost of Sales:				
Fuel Electric Costs	79	86	7	Primarily due to lower commodity costs.
Gas Supply Expenses	4	3	(1)	
Purchased Power	5	6	1	
Other Electric Cost	16	18	2	
Total Cost of Sales	103	113	10	
Gross Margin:				
Electric Margin	174	176	(1)	
Gas Margin	9	9	(0)	
Total Gross Margin	183	185	(2)	
Operating Expenses:				
O&M	53	58	5	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management and consulting services.
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	87	93	6	
Other income (expense)	(1)	(0)	(0)	
EBIT	96	92	4	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	78	74	4	
Income Tax Expense	28	29	0	
Net Income (loss) from ongoing operations	**50**	**46**	**$ 4**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 50	$ 46	$ 4	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 47	$ 43	$ 4	
Earnings Per Share - Ongoing	$ 0.07	$ 0.06	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

July 2016

($ Millions)

	YTD Actual	YTD Budget	YTD Variance	Comments
Revenues:				
Electric Revenues	$ 1,656	$ 1,760	$ (103)	Due to lower volumes driven by unfavorable weather, FAC revenue from lower fuel costs (see below), and lower industrial volumes.
Gas Revenues	179	207	(28)	See Gas Supply Expenses explanation below.
Total Revenues	1,835	1,966	(131)	
Cost of Sales:				
Fuel Electric Costs	461	532	71	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	75	100	24	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	32	34	2	
Other Electric Cost	87	103	16	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	656	769	113	
Gross Margin:				
Electric Margin	1,076	1,091	(15)	Lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $16 million partially offset by $2 million lower production costs and purchased power.
Gas Margin	104	107	(4)	
Total Gross Margin	1,180	1,198	(18)	
Operating Expenses:				
O&M	411	426	15	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management and consulting services.
Depreciation & Amortization	203	208	5	Lower depreciation primarily due to revised auto-retirements functionality as well as other project completion and spending updates.
Taxes, Other than Income	33	33	0	
Total Operating Expenses	646	667	20	
Other income (expense)	(5)	(5)	(1)	
EBIT	528	526	2	
Interest Expense	123	127	3	
Income from Ongoing Operations before income taxes	405	400	5	
Income Tax Expense	152	153	1	
Net Income (loss) from ongoing operations	**253**	**247**	**$ 6**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 253	$ 247	$ 6	
KY Regulated Financing Costs	(18)	$ (17)	(0)	
KY Regulated Net Income	$ 235	$ 230	$ 6	
Earnings Per Share - Ongoing	$ 0.34	$ 0.34	$ 0.01	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E

July 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 658	$ 687	$ (29)	Due to lower volumes driven by unfavorable weather, lower FAC revenue from lower fuel costs (see below), and lower industrial volumes.
Gas Revenues	179	207	(28)	See Gas Supply Expenses explanation below.
Total Revenues	837	893	(57)	
Cost of Sales:				
Fuel Electric Costs	180	199	19	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	75	100	24	Due to lower gas usage (mild weather) and prices
Purchased Power	29	35	6	
Other Electric Cost	33	41	8	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	318	375	57	
Gross Margin:				
Electric Margin	415	412	4	
Gas Margin	104	107	(4)	
Total Gross Margin	519	519	0	
Operating Expenses:				
O&M	183	192	9	Lower O&M primarily due to timing of plant maintenance and labor and burden savings.
Depreciation & Amortization	82	85	2	
Taxes, Other than Income	16	16	(0)	
Total Operating Expenses	282	293	11	
Other income (expense)	(3)	(2)	(1)	
EBIT	234	224	10	
Interest Expense	41	41	1	
Income from Ongoing Operations before income taxes	194	183	11	
Income Tax Expense	74	70	(4)	
Net Income (loss) from ongoing operations	**119**	**113**	**$ 7**	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - KU

July 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,023	$ 1,112	$ (89)	Due to lower volumes driven by unfavorable weather and by the loss of [redacted]) as a customer.
Gas Revenues	-	-	-	
Total Revenues	1,023	1,112	(89)	
Cost of Sales:				
Fuel Electric Costs	282	337	55	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	-	-	-	
Purchased Power	26	33	7	Lower purchased power due to mild weather.
Other Electric Cost	54	62	8	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	362	433	71	
Gross Margin:				
Electric Margin	661	679	(18)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	661	679	(18)	
Operating Expenses:				
O&M	212	220	8	Lower O&M primarily due to lower storm restoration, vegetation management and consulting services along with labor and burden savings.
Depreciation & Amortization	120	123	3	
Taxes, Other than Income	16	17	0	
Total Operating Expenses	349	360	11	
Other income (expense)	(2)	(3)	0	
EBIT	310	316	(7)	
Interest Expense	55	57	2	
Income from Ongoing Operations before income taxes	254	260	(5)	
Income Tax Expense	97	99	2	
Net Income (loss) from ongoing operations	**157**	**161**	**$ (3)**	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD
($ Millions)

July 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	97	96	1
Demand	50	51	(2)
Base Service Charge	14	14	(0)
Rate Mechanisms	15	17	(2)
Other Rev/Cost of Sales	(1)	(1)	0
Other Margin Items	(1)	(2)	1
	174	176	(1)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	43	43	(0)
Demand	17	17	(0)
Base Service Charge	6	6	(0)
Rate Mechanisms	8	9	(0)
Other Rev/Cost of Sales	(0)	(0)	0
Other Margin Items	(1)	(2)	1
	73	72	0

KU Electric Margin

	Actual	Budget	Variance
Base Energy	54	53	1
Demand	33	35	(1)
Base Service Charge	8	8	0
Rate Mechanisms	7	8	(1)
Other Rev/Cost of Sales	(1)	(0)	(0)
Other Margin Items	0	0	0
	102	104	(2)

LKE Base Energy Price/Vol Variance

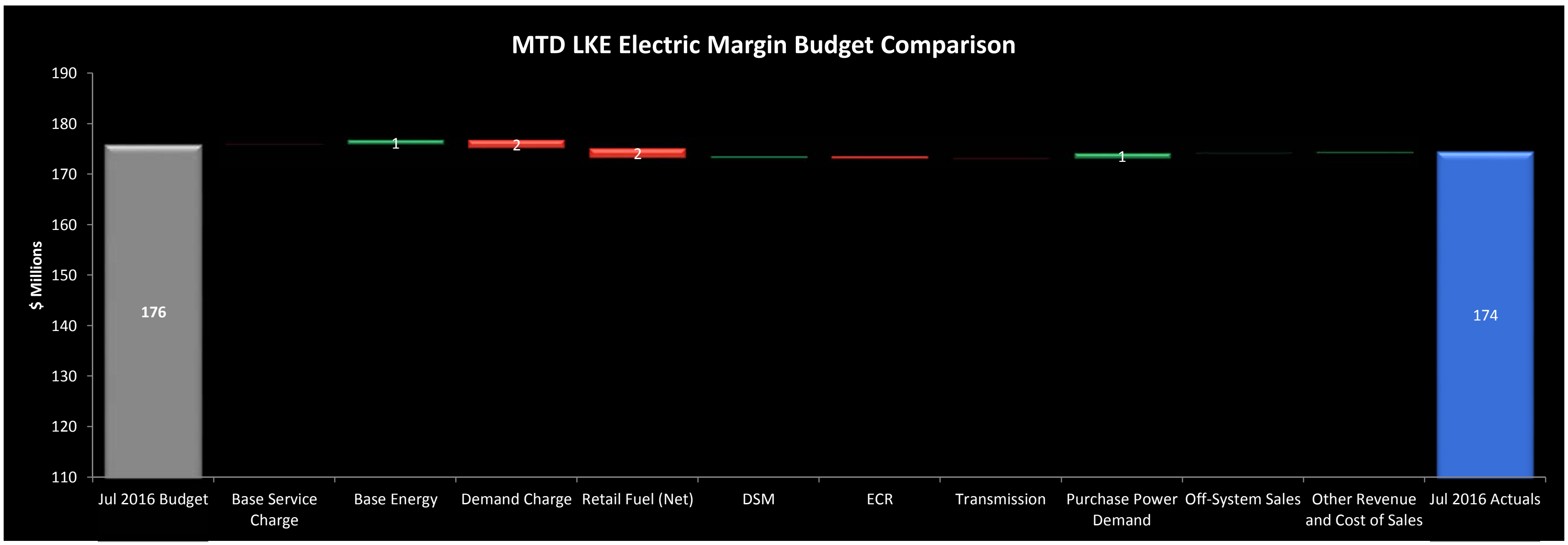
	Volume	Price	Total Variance
Residential	1	1	2
Commercial	1	(1)	0
Industrial	(1)	0	(1)
Public Authority	0	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	2	(1)	1

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	0	0	0
Commercial	1	(1)	0
Industrial	(1)	0	(0)
Public Authority	0	(0)	(0)
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	0	(1)	(0)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	1	0	2
Commercial	1	(0)	0
Industrial	(0)	0	(0)
Public Authority	(0)	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	1	(0)	1



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Electric Gross Margin Analysis - YTD **July 2016**
($ Millions)

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	565	577	(12)
Demand	318	323	(4)
Base Service Charge	96	96	(0)
Rate Mechanisms	109	111	(2)
Other Rev/Cost of Sales	(2)	(4)	2
Other Margin Items	(10)	(12)	2
	1076	1091	(15)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	227	227	(1)
Demand	105	103	2
Base Service Charge	39	39	(0)
Rate Mechanisms	56	56	(0)
Other Rev/Cost of Sales	(0)	(1)	1
Other Margin Items	(11)	(13)	2
	415	412	4

KU Electric Margin

	Actual	Budget	Variance
Base Energy	339	350	(11)
Demand	214	220	(6)
Base Service Charge	57	57	0
Rate Mechanisms	53	55	(2)
Other Rev/Cost of Sales	(2)	(3)	1
Other Margin Items	1	1	(0)
	661	679	(18)

LKE Base Energy Price/Vol Variance

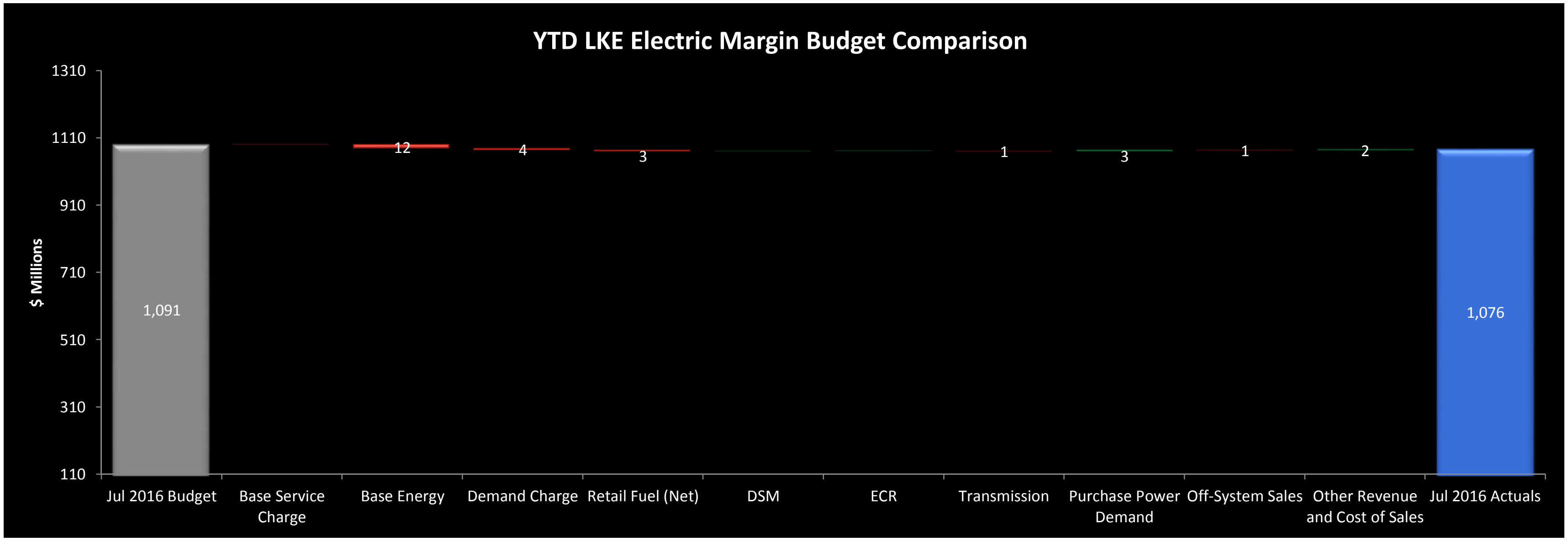
	Volume	Price	Total Variance
Residential	(7)	4	(4)
Commercial	1	(5)	(4)
Industrial	(4)	1	(2)
Public Authority	(0)	(0)	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(11)	(1)	(12)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(1)	2	0
Commercial	2	(3)	(1)
Industrial	(2)	1	(1)
Public Authority	0	0	1
Street Lights	0	0	0
Municipals	0	0	0
Other	0	0	0
	(0)	(0)	(1)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(6)	2	(4)
Commercial	(1)	(3)	(4)
Industrial	(2)	1	(1)
Public Authority	(0)	(1)	(1)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(11)	(1)	(11)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin

July 2016

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 36**	**$ 36**		**$ 0**
Gas Supply Costs								
Gas Supply Costs	(3)	(2)	$ (1)		$ (69)	$ (92)	$ 23	
GSC Revenue	3	2	$ 1		$ 70	$ 92	$ (23)	
Net Gas Supply Costs				**0**				**$ 0**
Retail Gas (a)	**2**	**2**		**(0)**	**$ 54**	**$ 61**		**$ (7)**
Wholesale Gas (a)	**-**	**-**		**-**	**$ -**	**$ -**		**$ -**
DSM	**0**	**0**		**(0)**	**$ 0**	**$ 1**		**$ (1)**
GLT	**1**	**1**		**0**	**$ 8**	**$ 8**		**$ 0**
WNA	**(0)**	**-**		**(0)**	**$ 3**	**$ -**		**$ 3**
Other Margin	**0**	**0**		**(0)**	**$ 1**	**$ 1**		**$ (0)**
Gas Margin Variance				**$ (0)**				**$ (4)**

(a) Retail and wholesale gas sales - excludes GSC

MTD	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	334,088	$ 2.87	$ 1	333,329	$ 2.87	$0.0	$0.0	$0.0
Commercial	0	239,150	1.99	1	250,852	2.10	($0.1)	($0.0)	($0.0)
Industrial	0	65,568	1.77	0	87,163	2.08	($0.1)	($0.0)	($0.0)
Public Authority	0	22,610	1.76	0	45,195	1.91	($0.0)	($0.0)	($0.0)
Transportation	0	1,021,458	0.45	0	802,220	0.53	$0.0	$0.1	($0.1)
Interdepartmental	0	23,735	13.28	0	200,092	1.54	$0.0	($0.3)	$0.3
Ultimate Consumer	$ 2	1,706,609	$ 1.39	$ 2	1,718,850	$ 1.44	($0.1)	($0.3)	$0.1

YTD	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 33	11,633,921	$ 2.87	$ 39	13,587,006	$ 2.87	($6)	$ (6)	$ (0)
Commercial	11	5,426,830	2.10	13	5,864,306	2.14	($1)	$ (1)	$ (0)
Industrial	1	691,099	2.02	2	849,980	2.12	($0)	$ (0)	$ (0)
Public Authority	2	752,836	2.06	2	923,192	2.09	($0)	$ (0)	$ (0)
Transportation	4	8,319,436	0.51	3	7,102,051	0.49	$1	$1	$0
Interdepartmental	2	192,460	11.20	2	721,055	2.94	$0	($2)	$2
Ultimate Consumer	$ 54	27,016,582	$ 2.00	$ 61	29,047,590	$ 2.09	($7)	($8)	$1

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O&M — July 2016

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	14	0	0	(0)	0	0	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	3	1	0	0	(0)	0	0
Energy Supply and Analysis	1	1	0	0	-	0	0	0
Generation Services	1	1	0	0	(0)	0	(0)	0
Electric Distribution	6	7	1	(0)	1	0	0	(0)
Gas Distribution	3	3	0	0	(0)	0	0	(0)
Safety and Technical Training	0	0	(0)	(0)	(0)	(0)	0	0
Customer Services	7	7	1	0	(0)	0	0	1
Chief Operations Officer	**33**	**36**	**3**	**0**	**1**	**1**	**1**	**0**
General Counsel	2	2	0	(0)	(0)	0	(0)	(0)
Human Resources	0	1	0	0	(0)	0	(0)	0
General Counsel & HR	**2**	**3**	**0**	**0**	**(0)**	**0**	**(0)**	**(0)**
Audit Services	0	0	0	0	-	(0)	(0)	0
Controller	1	1	(0)	(0)	-	(0)	0	0
Information Technology	4	5	1	0	0	0	0	0
Supply Chain	0	0	0	(0)	(0)	0	0	0
Treasurer	1	1	(0)	(0)	-	(0)	0	(0)
State Regulation and Rates	0	0	0	0	-	0	0	0
Chief Financial Officer	**7**	**7**	**0**	**0**	**0**	**0**	**0**	**0**
Corporate	**11**	**12**	**1**	**1**	**(0)**	**0**	**(0)**	**0**
O&M Total MTD	**53**	**58**	**5**	**1**	**1**	**2**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	115	119	4	2	(2)	2	6	(4)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	17	18	1	0	(0)	(0)	0	1
Energy Supply and Analysis	5	5	0	0	-	(0)	0	0
Generation Services	8	8	1	0	(0)	0	(0)	0
Electric Distribution	41	43	3	(1)	4	(0)	0	1
Gas Distribution	20	19	(0)	0	(1)	0	0	(0)
Safety and Technical Training	3	3	0	0	(0)	0	0	0
Customer Services	47	49	3	1	0	0	0	1
Chief Operations Officer	**255**	**266**	**11**	**2**	**1**	**2**	**6**	**(1)**
General Counsel	17	18	1	0	0	(0)	0	0
Human Resources	4	4	0	0	(0)	0	0	0
General Counsel & HR	**21**	**22**	**1**	**0**	**0**	**(0)**	**0**	**0**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	6	6	0	(0)	-	0	0	0
Information Technology	32	35	3	2	(0)	1	0	0
Supply Chain	2	2	(0)	(0)	(0)	0	0	0
Treasurer	6	7	0	(0)	-	(0)	(0)	1
State Regulation and Rates	2	2	(0)	0	-	0	(0)	0
Chief Financial Officer	**49**	**52**	**3**	**1**	**(0)**	**0**	**0**	**2**
Corporate	**85**	**86**	**1**	**0**	**(2)**	**2**	**(0)**	**1**
O&M Total YTD	**411**	**426**	**16**	**3**	**(0)**	**5**	**6**	**2**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	201	206	4	3	(3)	2	3	(2)
Project Engineering	0	1	0	0	-	(0)	(0)	0
Transmission	30	30	1	0	(0)	(0)	0	1
Energy Supply and Analysis	9	9	0	0	-	(0)	0	0
Generation Services	15	15	0	0	(0)	(0)	(0)	1
Electric Distribution	69	73	3	(1)	0	3	0	1
Gas Distribution	33	34	1	0	(0)	0	0	0
Safety and Technical Training	5	5	0	(0)	(0)	0	0	(0)
Customer Services	84	87	3	2	(0)	0	0	1
Chief Operations Officer	**446**	**459**	**12**	**4**	**(3)**	**6**	**4**	**2**
General Counsel	31	32	1	0	(0)	1	0	0
Human Resources	7	7	0	0	(0)	0	0	0
General Counsel & HR	**38**	**39**	**1**	**0**	**(0)**	**1**	**0**	**0**
Audit Services	2	2	0	0	-	(0)	0	0
Controller	10	10	0	(0)	-	0	0	0
Information Technology	58	60	2	2	0	0	0	0
Supply Chain	4	4	(0)	(0)	(0)	0	0	(0)
Treasurer	11	11	0	(0)	-	(0)	(0)	1
State Regulation and Rates	3	3	0	0	-	0	(0)	0
Chief Financial Officer	**87**	**90**	**2**	**1**	**0**	**(0)**	**0**	**1**
Corporate	**145**	**144**	**(1)**	**0**	**(1)**	**1**	**(0)**	**(1)**
O&M Total Full Year	**716**	**731**	**15**	**5**	**(4)**	**7**	**4**	**3**

Note: Schedules may not sum due to rounding.

Financing Activities — July 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.8	$ (0.0)	$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	0.0	923.8	923.8	(0.0)
Ave Bal	**$ 923.8**	**$ 923.8**	**$ (0.0)**	**$ 923.8**	**$ 923.8**	**$ (0.0)**
Interest Exp	**$ 7.2**	**$ 8.1**	**$ 0.9**	**$ 12.5**	**$ 13.9**	**$ 1.4**
Rate	**1.31%**	**1.48%**	**0.17%**	**1.33%**	**1.48%**	**0.14%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 103.4**	**$ 103.4**	**$ 0.0**	**$ 175.3**	**$ 175.3**	**$ -**
Rate	**4.15%**	**4.15%**	**0.00%**	**4.10%**	**4.10%**	**0.00%**
Short-term Debt						
Beg Bal	$ 318.9	$ 282.0	$ (36.9)	$ 451.8	$ 347.7	$ (104.1)
End Bal	293.1	256.8	(36.4)	488.8	347.7	(141.1)
Ave Bal	**$ 306.0**	**$ 269.4**	**$ (36.6)**	**$ 470.3**	**$ 347.7**	**$ (122.6)**
Interest Exp	**$ 2.2**	**$ 2.8**	**$ 0.5**	**$ 5.0**	**$ 4.8**	**$ (0.3)**
Rate	**1.24%**	**1.75%**	**0.50%**	**1.05%**	**1.35%**	**0.29%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (44.0)	$ 2.4	$ (42.2)	$ (39.6)	$ 2.6
End Bal	(44.1)	(43.2)	0.8	(40.9)	(39.6)	1.3
Ave Bal	**$ (45.2)**	**$ (43.6)**	**$ 1.6**	**$ (41.6)**	**$ (39.6)**	**$ 2.0**
Total End Bal	**$ 5,382.9**	**$ 5,347.4**	**$ (35.5)**	**$ 5,581.8**	**$ 5,441.9**	**$ (139.9)**
Total Average Bal	**$ 5,394.7**	**$ 5,359.6**	**$ (35.1)**	**$ 5,562.6**	**$ 5,441.9**	**$ (120.7)**
Total Expense Excl I/C [(1)]	**$ 123.2**	**$ 126.6**	**$ 3.4**	**$ 213.1**	**$ 217.2**	**$ 4.1**
Rate	**3.83%**	**3.96%**	**0.13%**	**3.74%**	**3.90%**	**0.16%**

[(1)] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[(2)]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 143		$ 157
LG&E	500	128		372
KU	598	22	$ 198	378
TOTAL	$ 1,398	$ 293	$ 198	$ 907

[(2)] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	17%	17%	25%	25%	25%	25%
CFO pre-WC + Interest / Interest	5.4	5.5	7.5	7.8	7.4	7.5
CFO pre-WC - Dividends / Debt	15%	16%	25%	25%	18%	18%
Debt to Capitalization[2]	47%	47%	38%	39%	38%	39%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

July 2016

($ Millions)

	7/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 17	$ 16	$ 1	
Accounts Receivable (Trade)	422	397	25	
Inventory	280	260	21	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	20	64	(44)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	46	46	(1)	
Total Current Assets	786	783	3	
Property, Plant, and Equipment	11,560	11,702	(142)	
Intangible Assets	108	99	9	
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	772	742	31	
Goodwill	997	997	-	
Other Long-term Assets	79	81	(1)	
Total Assets	**$ 14,303**	**$ 14,405**	**$ (102)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 249	$ 274	$ (25)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	54	52	2	
Derivative Liability	6	5	1	
Accrued Taxes	68	109	(41)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	23	30	(7)	
Other Current Liabilities	220	210	10	
Total Current Liabilities	620	680	(60)	
Debt - Affiliated Company	543	400	143	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016 and quarterly pay off of any cash needed for operations on non quarter months. The forecast does not assume any pay off of the short term debt with affiliate.
Debt [(1)]	4,840	4,947	(108)	
Total Debt	5,383	5,347	36	
Deferred Tax Liabilities	1,578	1,582	(4)	
Investment Tax Credit	133	126	7	
Accum Provision for Pension & Related Benefits	279	268	10	
Asset Retirement Obligation	465	498	(33)	
Regulatory Liabilities Non Current	915	878	37	
Derivative Liability	50	42	8	
Other Liabilities	183	195	(13)	
Total Deferred Credits and Other Liabilities	3,603	3,590	14	
Equity	4,697	4,787	(90)	
Total Liabilities and Equity	**$ 14,303**	**$ 14,405**	**$ (102)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.

Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E — July 2016

($ Millions)

	7/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 6	$ 5	$ 1	
Accounts Receivable (Trade)	181	170	11	
Inventory	126	112	15	Higher actual due to lower than expected usage and higher than budgeted inventory levels.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	7	25	(18)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	48	35	13	Due to higher accounts receivable from affiliate related to charges for Trimble County CCR transport and generator field project, inventory and fuel.
Total Current Assets	369	347	22	
Property, Plant, and Equipment	4,920	5,006	(86)	
Intangible Assets	6	1	5	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	439	419	20	
Goodwill	-	-	-	
Other Long-term Assets	21	19	3	
Total Assets	**$ 5,756**	**$ 5,791**	**$ (36)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 166	$ 189	$ (23)	Lower balance due to decrease in intercompany purchased power, decrease in charges allocated from LKS and lower gas purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	37	56	$ (19)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	7	13	(6)	
Other Current Liabilities	83	74	9	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Total Current Liabilities	326	362	(36)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,770	1,785	(15)	
Total Debt	1,770	1,785	(15)	
Deferred Tax Liabilities	888	892	(4)	
Investment Tax Credit	37	34	3	
Accum Provision for Pension & Related Benefits	49	41	9	
Asset Retirement Obligation	136	153	(17)	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Regulatory Liabilities Non Current	368	350	18	
Derivative Liability	50	42	8	
Other Liabilities	86	89	(3)	
Total Deferred Credits and Other Liabilities	1,614	1,600	14	
Equity	2,046	2,044	1	
Total Liabilities and Equity	**$ 5,756**	**$ 5,791**	**$ (36)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU

July 2016

($ Millions)

	7/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 11	$ 5	$ 6	
Accounts Receivable (Trade)	240	226	14	
Inventory	154	148	6	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	13	39	(26)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	22	23	(1)	
Total Current Assets	440	441	(1)	
Property, Plant, and Equipment	6,633	6,689	(57)	
Intangible Assets	13	9	4	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	328	319	9	
Goodwill	-	-	-	
Other Long-term Assets	56	53	3	
Total Assets	**$ 7,469**	**$ 7,512**	**$ (42)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 117	$ 128	$ (11)	
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	28	26	2	
Derivative Liability	-	-	-	
Accrued Taxes	37	53	(17)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	16	17	(1)	
Other Current Liabilities	91	86	5	
Total Current Liabilities	289	310	(21)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,345	2,362	(17)	
Total Debt	2,345	2,362	(17)	
Deferred Tax Liabilities	1,120	1,127	(8)	
Investment Tax Credit	96	92	4	
Accum Provision for Pension & Related Benefits	40	38	2	
Asset Retirement Obligation	330	345	(16)	
Regulatory Liabilities Non Current	459	440	19	
Derivative Liability	-	-	-	
Other Liabilities	47	56	(8)	
Total Deferred Credits and Other Liabilities	2,092	2,098	(6)	
Equity	2,744	2,741	2	
Total Liabilities and Equity	**$ 7,469**	**$ 7,512**	**$ (42)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

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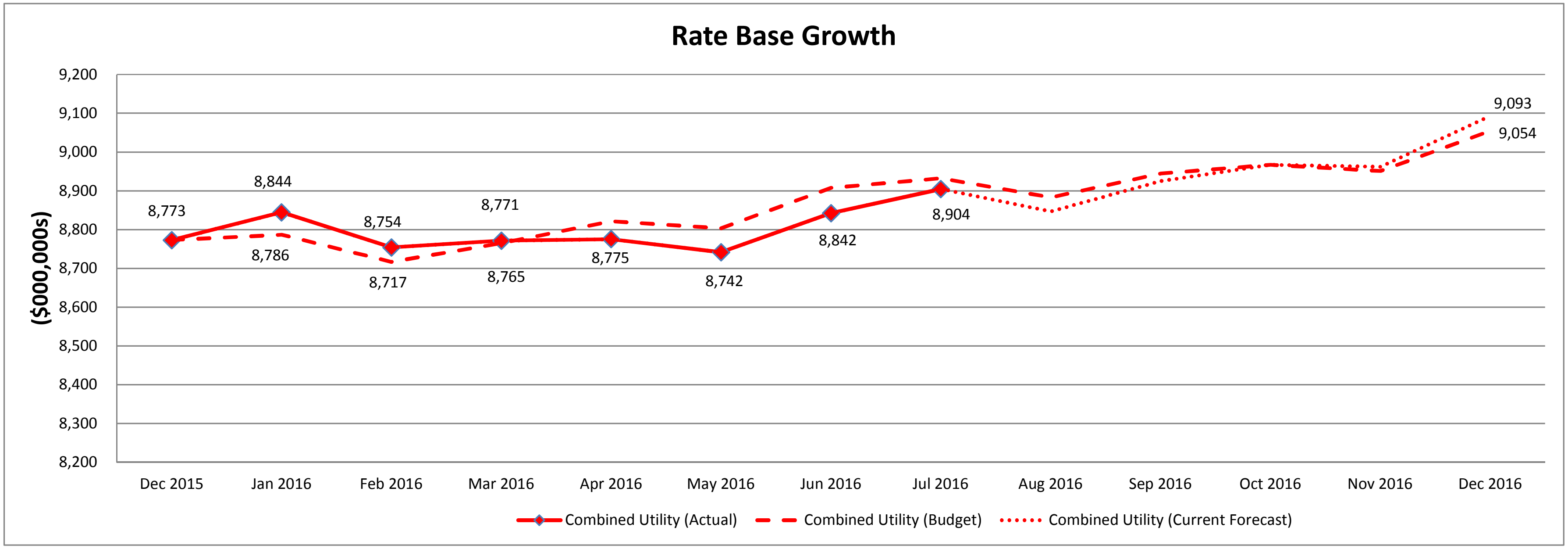
Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,773
8,844
8,754
8,771
8,786
8,717
8,765
8,775
8,742
8,842
8,904
9,093
9,054
Dec 2015
Jan 2016
Feb 2016
Mar 2016
Apr 2016
May 2016
Jun 2016
Jul 2016
Aug 2016
Sep 2016
Oct 2016
Nov 2016
Dec 2016
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

Performance Report

August 2016

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Kentucky Regulated Dashboard

August 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	2.59	2.24	1.08	1.15	1.38	1.22
Employee lost-time incidents	0	1	2	7	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,402	3,398	23,068	23,981	34,050	34,964
Utility EFOR	2.5%	5.7%	6.5%	5.7%	N/A	5.7%
Utility EAF	96.1%	84.9%	84.3%	84.9%	N/A	82.3%
Steam Fleet Commercial Availability	98.3%	92.8%	93.7%	92.8%	N/A	92.8%
Combined SAIFI	0.08	0.09	0.77	0.73	N/A	1.03
Combined SAIDI (minutes)	8.95	8.00	75.46	68.09	N/A	94.09
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	1,134	1,143	7,446	7,589	10,687	10,847
Commercial	823	760	5,387	5,278	7,924	7,793
Industrial	875	923	6,304	6,783	9,439	10,089
Municipals	190	184	1,287	1,296	1,876	1,886
Other	285	258	1,898	1,894	2,793	2,798
Off-System Sales	22	2	124	287	156	322
Total	3,329	3,270	22,446	23,127	32,875	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.35%			
Commercial			1.56%			
Industrial			-4.47%			
Municipal			0.15%			
Other			0.29%			
Total			-1.71%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$180	$180	$1,256	$1,271	$1,842	$1,870
Gas Margins	9	9	113	116	170	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$56	$83	$487	$667	$872	$955
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$57	$61	$468	$488	$716	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,490	3,589	3,490	3,589	3,563	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	3	15	N/A	16
NERC Possible Violations[3]	0	1	1	6	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[4]	9.8%	9.8%	9.8%

Variance Explanations

• YTD lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $18 million, $4 million lower gas margins and $2 million lower retail rate mechanism revenue. This was partially offset by $5 million lower production costs and other margin components.

• Current month lower O&M primarily due to lower labor and burden costs along with savings in outside services.

• YTD lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management and outside services.

• Current month capital expenditures were lower, primarily due to lower than budgeted ECR spending on CCR projects.

• YTD capital expenditures were lower, primarily due to lower level of ECR spending on Environmental Air projects at Mill Creek, permitting delays related to CCR projects at Trimble County and timing related to Transmission projects.

Major Developments

• LG&E won another J.D. Power award for customer satisfaction, ranking first among the mid-sized utilities in the Midwest region of the 2016 Gas Utility Residential Study. This latest award follows KU's top ranking in the 2016 Electric Utility Residential Customer Satisfaction Study released in July.

• KU recently priced a refinancing for $96 million of pollution control bonds for three years at an interest rate of 1.05 percent. There was strong demand for the bonds from investors.

• LG&E and Louisville Metro entered into a 5 year gas franchise agreement that is renewable for up to a total of 20 years. Through the negotiation process, the parties agreed that the issue of cost recovery could be litigated, and in the interim, no payments will be paid. If LG&E's position and current practice that the franchise fee should be recovered as a line item on customer bills prevail, the fee will revert to zero. If Louisville Metro's position that the franchise fee should be socialized in base rates among all LG&E customers ultimately prevails, any amounts owing will be prospective only. LG&E has filed with the KPSC a motion for a Declaratory Order confirming its current practice to recover all franchise fees as a line item on the bill applicable to those in the accessing authorities jurisdiction.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms.

(3) The possible violation issues are believed to be minimal risk.

(4) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

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Income Statement: Actual vs. Budget (Month) - LKE Consolidated — August 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 280	$ 292	$ (12)	Due to lower residential and industrial (primarily [redacted]) revenues.
Gas Revenues	13	13	(0)	
Total Revenues	292	305	(12)	
Cost of Sales:				
Fuel Electric Costs	80	89	9	Primarily due to lower commodity costs.
Gas Supply Expenses	3	4	0	
Purchased Power	5	6	1	
Other Electric Cost	15	17	2	
Total Cost of Sales	104	115	11	
Gross Margin:				
Electric Margin	180	180	(1)	
Gas Margin	9	9	(0)	
Total Gross Margin	189	189	(1)	
Operating Expenses:				
O&M	57	62	5	Lower O&M primarily due to lower labor and burden costs along with savings in outside services
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	91	96	5	
Other income (expense)	(0)	(0)	0	
EBIT	98	93	5	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	80	75	5	
Income Tax Expense	29	29	(1)	
Net Income (loss) from ongoing operations	**50**	**46**	**$ 4**	
Non Operating Income	-	-	-	
Discontinued Operations	(0)	(0)	(0)	
Net Income (loss)	$ 50	$ 46	$ 4	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 48	$ 44	$ 4	
Earnings Per Share - Ongoing	$ 0.07	$ 0.06	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

August 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,936	$ 2,052	$ (115)	Due to lower volumes driven by unfavorable weather, FAC revenue from lower fuel costs (see below), and lower industrial volumes.
Gas Revenues	191	219	(28)	See Gas Supply Expenses explanation below.
Total Revenues	2,128	2,271	(143)	
Cost of Sales:				
Fuel Electric Costs	541	621	80	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	79	103	24	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	37	39	2	
Other Electric Cost	103	120	18	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	759	884	124	
Gross Margin:				
Electric Margin	1,256	1,271	(15)	Lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $18 million and $2 million lower retail rate mechanism revenue. This was partially offset by $5 million lower production costs and other margin components.
Gas Margin	113	116	(4)	
Total Gross Margin	1,368	1,387	(19)	
Operating Expenses:				
O&M	468	487	20	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management and outside services.
Depreciation & Amortization	232	238	6	Lower depreciation primarily due to project completion and spending updates as well as higher level of retirements this year.
Taxes, Other than Income	38	38	(0)	
Total Operating Expenses	737	763	26	
Other income (expense)	(5)	(5)	(0)	
EBIT	626	619	6	
Interest Expense	141	145	4	
Income from Ongoing Operations before income taxes	485	475	10	
Income Tax Expense	181	182	0	
Net Income (loss) from ongoing operations	**303**	**293**	**$ 10**	
Non Operating Income	-	-	-	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 303	$ 293	$ 10	
KY Regulated Financing Costs	(20)	$ (20)	(0)	
KY Regulated Net Income	$ 283	$ 273	$ 10	
Earnings Per Share - Ongoing	$ 0.42	$ 0.40	$ 0.01	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E

August 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 774	$ 807	$ (33)	Due to lower volumes driven by unfavorable weather, lower FAC revenue from lower fuel costs (see below), and lower industrial volumes.
Gas Revenues	191	219	(28)	See Gas Supply Expenses explanation below.
Total Revenues	965	1,027	(61)	
Cost of Sales:				
Fuel Electric Costs	210	232	22	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	79	103	24	Due to lower gas usage (mild weather) and prices
Purchased Power	34	41	7	
Other Electric Cost	40	48	8	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	363	425	62	
Gross Margin:				
Electric Margin	490	486	4	
Gas Margin	113	116	(4)	
Total Gross Margin	602	602	0	
Operating Expenses:				
O&M	208	219	11	Lower O&M primarily due to timing of plant maintenance and outages, vegetation management, storm restoration and labor and burden savings.
Depreciation & Amortization	94	97	3	
Taxes, Other than Income	19	19	(0)	
Total Operating Expenses	321	335	14	
Other income (expense)	(3)	(2)	(1)	
EBIT	278	265	13	
Interest Expense	47	47	1	
Income from Ongoing Operations before income taxes	232	218	14	
Income Tax Expense	89	84	(5)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**143**	**134**	**$ 9**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

August 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,189	$ 1,287	$ (99)	Due to lower volumes driven by unfavorable weather and by the loss of [redacted]) as a customer.
Gas Revenues	-	-	-	
Total Revenues	1,189	1,287	(99)	
Cost of Sales:				
Fuel Electric Costs	332	393	61	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	-	-	-	
Purchased Power	28	37	9	Lower purchased power due to mild weather.
Other Electric Cost	63	72	10	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	423	502	79	
Gross Margin:				
Electric Margin	766	786	(20)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	766	786	(20)	
Operating Expenses:				
O&M	243	252	10	Lower O&M primarily due to timing of plant maintenance, lower storm restoration, vegetation management and consulting services along with labor and burden savings.
Depreciation & Amortization	138	141	3	
Taxes, Other than Income	19	19	0	
Total Operating Expenses	399	412	13	
Other income (expense)	(2)	(3)	1	
EBIT	365	370	(6)	
Interest Expense	63	65	2	
Income from Ongoing Operations before income taxes	301	305	(4)	
Income Tax Expense	115	117	1	
Net Income (loss) from ongoing operations	**186**	**189**	**$ (2)**	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD **August 2016**
($ Millions)

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	100	99	1
Demand	50	53	(3)
Base Service Charge	14	14	(0)
Rate Mechanisms	17	17	0
Other Rev/Cost of Sales	(0)	(1)	1
Other Margin Items	(1)	(2)	0
	180	180	(1)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	45	44	0
Demand	17	17	(0)
Base Service Charge	6	6	(0)
Rate Mechanisms	9	9	0
Other Rev/Cost of Sales	0	(0)	0
Other Margin Items	(2)	(2)	0
	74	74	1

KU Electric Margin

	Actual	Budget	Variance
Base Energy	55	55	1
Demand	33	36	(2)
Base Service Charge	8	8	0
Rate Mechanisms	8	8	0
Other Rev/Cost of Sales	(0)	(1)	0
Other Margin Items	0	0	0
	105	106	(1)

LKE Base Energy Price/Vol Variance

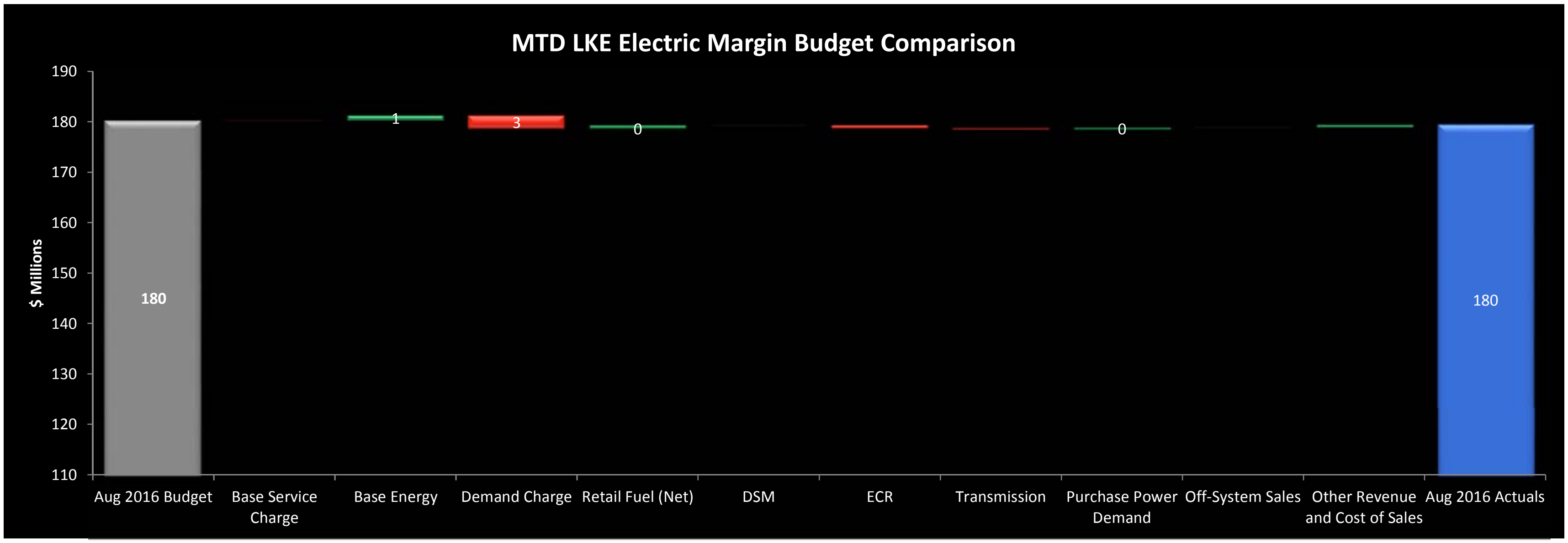
	Volume	Price	Total Variance
Residential	(1)	1	0
Commercial	2	(1)	1
Industrial	(0)	0	(0)
Public Authority	1	(0)	0
Street Lights	(0)	0	0
Municipals	0	(0)	(0)
Other	0	0	0
	2	(1)	1

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(1)	0	(0)
Commercial	1	(1)	1
Industrial	(0)	0	(0)
Public Authority	0	(0)	0
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	1	(0)	0

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	0	0	0
Commercial	1	(0)	0
Industrial	(0)	0	(0)
Public Authority	0	(0)	0
Street Lights	(0)	0	0
Municipals	0	(0)	(0)
Other	0	0	0
	1	(0)	1



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

Electric Gross Margin Analysis - YTD

($ Millions)

August 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	665	676	(11)
Demand	369	375	(7)
Base Service Charge	110	110	(0)
Rate Mechanisms	126	129	(2)
Other Rev/Cost of Sales	(2)	(5)	3
Other Margin Items	(12)	(14)	2
	1256	1271	(15)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	271	271	(0)
Demand	122	120	1
Base Service Charge	45	45	(0)
Rate Mechanisms	65	65	(0)
Other Rev/Cost of Sales	(0)	(2)	1
Other Margin Items	(13)	(15)	2
	490	485	4

KU Electric Margin

	Actual	Budget	Variance
Base Energy	394	405	(11)
Demand	247	255	(8)
Base Service Charge	65	65	0
Rate Mechanisms	61	63	(2)
Other Rev/Cost of Sales	(2)	(4)	1
Other Margin Items	1	1	(0)
	766	786	(20)

LKE Base Energy Price/Vol Variance

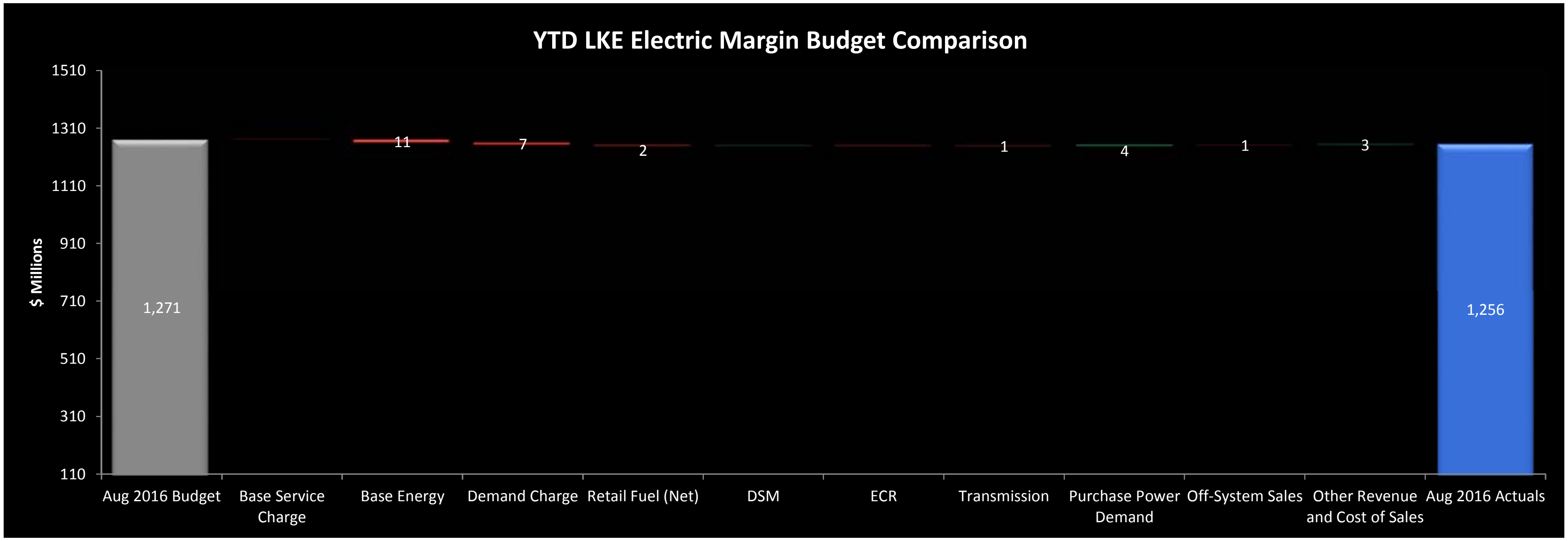
	Volume	Price	Total Variance
Residential	(8)	4	(3)
Commercial	3	(6)	(3)
Industrial	(4)	2	(2)
Public Authority	0	(0)	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(9)	(1)	(11)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(2)	2	0
Commercial	4	(3)	0
Industrial	(2)	1	(1)
Public Authority	0	0	1
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	0	(1)	(0)

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(6)	2	(4)
Commercial	(0)	(3)	(3)
Industrial	(2)	1	(1)
Public Authority	(0)	(1)	(1)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(10)	(1)	(11)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

Gas Gross Margin — August 2016

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 42**	**$ 42**		**$ 0**
Gas Supply Costs								
Gas Supply Costs	(3)	(2)	$ (0)		$ (72)	$ (95)	$ 23	
GSC Revenue	3	2	$ 0		$ 72	$ 95	$ (23)	
Net Gas Supply Costs				**0**				**$ 0**
Retail Gas (a)	**2**	**3**		**(0)**	**$ 57**	**$ 63**		**$ (7)**
Wholesale Gas (a)	**-**	**-**		**-**	**$ -**	**$ -**		**$ -**
DSM	**0**	**0**		**(0)**	**$ 0**	**$ 1**		**$ (1)**
GLT	**1**	**1**		**0**	**$ 10**	**$ 9**		**$ 0**
WNA	**0**	**-**		**0**	**$ 3**	**$ -**		**$ 3**
Other Margin	**0**	**0**		**(0)**	**$ 1**	**$ 1**		**$ (0)**
Gas Margin Variance				**$ (0)**				**$ (4)**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	344,201	$ 2.87	$ 1	354,424	$ 2.87	($0.0)	($0.0)	($0.0)
Commercial	0	246,662	2.00	1	255,518	2.10	($0.0)	($0.0)	($0.0)
Industrial	0	68,933	1.72	0	90,768	2.08	($0.1)	($0.0)	($0.0)
Public Authority	0	26,645	1.91	0	45,998	1.91	($0.0)	($0.0)	$0.0
Transportation	0	944,333	0.51	0	832,139	0.52	$0.1	$0.1	($0.0)
Interdepartmental	0	23,880	12.91	0	190,824	1.61	$0.0	($0.3)	$0.3
Ultimate Consumer	$ 2	1,654,654	$ 1.48	$ 3	1,769,671	$ 1.45	($0.1)	($0.3)	$0.2

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 34	11,978,122	$ 2.87	$ 40	13,941,429	$ 2.87	($6)	$ (6)	$ (0)
Commercial	12	5,673,492	2.09	13	6,119,824	2.14	($1)	$ (1)	$ (0)
Industrial	2	760,032	1.99	2	940,749	2.12	($0)	$ (0)	$ (0)
Public Authority	2	779,481	2.05	2	969,190	2.08	($0)	$ (0)	$ (0)
Transportation	5	9,263,769	0.51	4	7,934,190	0.49	$1	$1	$0
Interdepartmental	2	216,340	11.39	2	911,879	2.66	$0	($2)	$2
Ultimate Consumer	$ 57	28,671,236	$ 1.97	$ 63	30,817,262	$ 2.06	($7)	($9)	$2

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	15	1	1	(1)	1	0	(0)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	3	0	0	0	(0)	0	0
Energy Supply and Analysis	1	1	0	0	-	0	0	(0)
Generation Services	1	1	(0)	0	(0)	(0)	(0)	0
Electric Distribution	6	7	1	0	0	0	(0)	0
Gas Distribution	3	3	0	0	(0)	0	0	0
Safety and Technical Training	0	0	(0)	(0)	(0)	(0)	(0)	0
Customer Services	8	8	(0)	0	0	0	0	(0)
Chief Operations Officer	**36**	**38**	**2**	**1**	**(0)**	**1**	**0**	**(0)**
General Counsel	2	3	1	0	0	0	(0)	0
Human Resources	1	1	0	0	(0)	0	0	0
General Counsel & HR	**3**	**4**	**1**	**0**	**0**	**0**	**(0)**	**0**
Audit Services	0	0	0	0	-	(0)	0	(0)
Controller	1	1	0	0	-	0	0	(0)
Information Technology	5	5	0	1	(0)	0	(0)	(0)
Supply Chain	0	0	0	0	(0)	0	0	(0)
Treasurer	1	1	0	0	-	0	(0)	(0)
State Regulation and Rates	0	0	0	0	-	0	(0)	0
Chief Financial Officer	**8**	**8**	**0**	**1**	**(0)**	**0**	**(0)**	**(1)**
Corporate	**11**	**12**	**1**	**1**	**(0)**	**0**	**(0)**	**1**
O&M Total MTD	**57**	**61**	**4**	**3**	**(1)**	**2**	**0**	**0**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	129	134	5	3	(2)	3	6	(4)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	19	20	1	0	(0)	(0)	0	1
Energy Supply and Analysis	6	6	0	0	-	(0)	0	0
Generation Services	9	10	0	0	(0)	(0)	(0)	1
Electric Distribution	47	50	3	(1)	4	(0)	0	1
Gas Distribution	22	23	0	0	(1)	1	0	(0)
Safety and Technical Training	3	3	0	0	(0)	0	0	0
Customer Services	55	57	3	1	0	0	0	1
Chief Operations Officer	**291**	**304**	**13**	**3**	**1**	**4**	**7**	**(1)**
General Counsel	20	21	1	0	0	(0)	0	1
Human Resources	4	5	1	0	(0)	0	0	0
General Counsel & HR	**24**	**26**	**2**	**0**	**0**	**0**	**0**	**1**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	6	7	0	(0)	-	0	0	0
Information Technology	37	40	3	2	(0)	1	0	0
Supply Chain	3	3	(0)	(0)	(0)	0	0	0
Treasurer	7	7	0	(0)	-	(0)	(0)	1
State Regulation and Rates	2	2	(0)	0	-	0	(0)	0
Chief Financial Officer	**57**	**60**	**3**	**2**	**(0)**	**1**	**(0)**	**1**
Corporate	**96**	**98**	**2**	**1**	**(2)**	**2**	**(0)**	**1**
O&M Total YTD	**468**	**488**	**20**	**6**	**(1)**	**6**	**7**	**2**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	201	206	4	3	(3)	2	3	(2)
Project Engineering	0	1	0	0	-	(0)	(0)	0
Transmission	30	30	1	0	(0)	(0)	0	1
Energy Supply and Analysis	9	9	0	0	-	(0)	0	0
Generation Services	15	15	0	0	(0)	(0)	(0)	1
Electric Distribution	69	73	3	(1)	0	3	0	1
Gas Distribution	33	34	1	0	(0)	0	0	0
Safety and Technical Training	5	5	0	(0)	(0)	0	0	(0)
Customer Services	84	87	3	2	(0)	0	0	1
Chief Operations Officer	**446**	**459**	**12**	**4**	**(3)**	**6**	**4**	**2**
General Counsel	31	32	1	0	(0)	1	0	0
Human Resources	7	7	0	0	(0)	0	0	0
General Counsel & HR	**38**	**39**	**1**	**0**	**(0)**	**1**	**0**	**0**
Audit Services	2	2	0	0	-	(0)	0	0
Controller	10	10	0	(0)	-	0	0	0
Information Technology	58	60	2	2	0	0	0	0
Supply Chain	4	4	(0)	(0)	(0)	0	0	(0)
Treasurer	11	11	0	(0)	-	(0)	(0)	1
State Regulation and Rates	3	3	0	0	-	0	(0)	0
Chief Financial Officer	**87**	**90**	**2**	**1**	**0**	**(0)**	**0**	**1**
Corporate	**145**	**144**	**(1)**	**0**	**(1)**	**1**	**(0)**	**(1)**
O&M Total Full Year	**716**	**731**	**15**	**5**	**(4)**	**7**	**4**	**3**

Note: Schedules may not sum due to rounding.

Financing Activities — August 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.8	$ (0.0)	$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	(0.0)	923.8	923.8	(0.0)
Ave Bal	**$ 923.8**	**$ 923.8**	**$ (0.0)**	**$ 923.8**	**$ 923.8**	**$ (0.0)**
Interest Exp	**$ 8.3**	**$ 9.3**	**$ 0.9**	**$ 12.5**	**$ 13.9**	**$ 1.4**
Rate	**1.33%**	**1.48%**	**0.15%**	**1.33%**	**1.48%**	**0.14%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 118.2**	**$ 118.2**	**$ (0.0)**	**$ 175.3**	**$ 175.3**	**$ -**
Rate	**4.14%**	**4.14%**	**0.00%**	**4.10%**	**4.10%**	**0.00%**
Short-term Debt						
Beg Bal	$ 318.9	$ 256.8	$ (62.1)	$ 451.8	$ 347.7	$ (104.1)
End Bal	225.5	216.4	(9.2)	488.8	347.7	(141.1)
Ave Bal	**$ 272.2**	**$ 236.6**	**$ (35.7)**	**$ 470.3**	**$ 347.7**	**$ (122.6)**
Interest Exp	**$ 2.6**	**$ 3.1**	**$ 0.6**	**$ 5.0**	**$ 4.8**	**$ (0.3)**
Rate	**1.39%**	**1.95%**	**0.56%**	**1.05%**	**1.35%**	**0.29%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (43.2)	$ 3.1	$ (42.2)	$ (39.6)	$ 2.6
End Bal	(44.4)	(42.5)	1.9	(40.9)	(39.6)	1.3
Ave Bal	**$ (45.4)**	**$ (42.9)**	**$ 2.5**	**$ (41.6)**	**$ (39.6)**	**$ 2.0**
Total End Bal	**$ 5,314.9**	**$ 5,307.7**	**$ (7.2)**	**$ 5,581.8**	**$ 5,441.9**	**$ (139.9)**
Total Average Bal	**$ 5,360.7**	**$ 5,327.5**	**$ (33.2)**	**$ 5,562.6**	**$ 5,441.9**	**$ (120.7)**
Total Expense Excl I/C [1]	**$ 141.1**	**$ 144.7**	**$ 3.6**	**$ 213.1**	**$ 217.2**	**$ 4.1**
Rate	**3.85%**	**3.97%**	**0.12%**	**3.74%**	**3.90%**	**0.16%**

[1] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[2]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 152		$ 148
LG&E	500	74		426
KU	598	-	$ 198	400
TOTAL	$ 1,398	$ 226	$ 198	$ 974

[2] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	18%	18%	25%	26%	26%	26%
CFO pre-WC + Interest / Interest	5.6	5.4	7.5	7.6	7.4	7.4
CFO pre-WC - Dividends / Debt	17%	17%	25%	26%	19%	19%
Debt to Capitalization[2]	47%	46%	38%	38%	38%	38%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	19%	27%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.7	5.6	7.8	7.7	7.7	7.1
CFO pre-WC - Dividends / Debt	11%	12%	20%	20%	19%	19%
Debt to Capitalization[2]	45%	44%	37%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

August 2016

($ Millions)

	8/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 18	$ 20	$ (3)	
Accounts Receivable (Trade)	424	404	19	
Inventory	282	261	21	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	18	66	(48)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	44	44	(0)	
Total Current Assets	785	796	(11)	
Property, Plant, and Equipment	11,575	11,744	(169)	
Intangible Assets	106	95	10	Amortization related to software classified as intangibles in budget versus PP&E in actuals.
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	776	744	32	
Goodwill	997	997	-	
Other Long-term Assets	78	82	(3)	
Total Assets	**$ 14,318**	**$ 14,458**	**$ (140)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 232	$ 275	$ (43)	Due to decrease in accruals and lower coal purchases, partially offset by an increase in natural gas purchases.
Dividends Payable to Affiliated Companies	110	-	110	
Customer Deposits	54	52	3	
Derivative Liability	6	5	1	
Accrued Taxes	106	143	(37)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	27	30	(3)	
Other Current Liabilities	233	226	7	
Total Current Liabilities	768	731	37	
Debt - Affiliated Company	552	400	152	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016 and quarterly pay off of any cash needed for operations on non quarter months. The forecast does not assume any pay off of the short term debt with affiliate.
Debt [(1)]	4,763	4,908	(144)	
Total Debt	5,315	5,308	7	
Deferred Tax Liabilities	1,575	1,582	(6)	
Investment Tax Credit	133	126	7	
Accum Provision for Pension & Related Benefits	281	269	12	
Asset Retirement Obligation	465	500	(35)	
Regulatory Liabilities Non Current	914	872	42	
Derivative Liability	49	42	7	
Other Liabilities	181	196	(15)	
Total Deferred Credits and Other Liabilities	3,597	3,586	12	
Equity	4,637	4,834	(197)	
Total Liabilities and Equity	**$ 14,318**	**$ 14,458**	**$ (140)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

August 2016

($ Millions)

	8/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 7	$ 5	$ 2	
Accounts Receivable (Trade)	181	172	9	
Inventory	129	119	11	Higher actual due to lower than expected usage and higher than budgeted inventory levels.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	5	25	(20)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	40	34	6	
Total Current Assets	363	356	8	
Property, Plant, and Equipment	4,933	5,035	(103)	
Intangible Assets	6	0	6	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	439	418	21	
Goodwill	-	-	-	
Other Long-term Assets	21	19	3	
Total Assets	**$ 5,763**	**$ 5,829**	**$ (66)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 153	$ 189	$ (35)	Due to decrease in accruals, contract retainage and lower coal purchases, partially offset by an increase in natural gas purchases.
Dividends Payable to Affiliated Companies	26	24	2	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	55	72	$ (17)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	7	13	(6)	
Other Current Liabilities	86	78	8	
Total Current Liabilities	359	406	(47)	
Debt - Affiliated Company	33	-	33	
Debt [(1)]	1,716	1,783	(67)	
Total Debt	1,749	1,783	(34)	
Deferred Tax Liabilities	887	892	(5)	
Investment Tax Credit	37	34	3	
Accum Provision for Pension & Related Benefits	50	40	10	Primarily due to true-up of funded status.
Asset Retirement Obligation	134	153	(19)	Primarily due to reclassification of ARO liability from non-current to current liabilities.
Regulatory Liabilities Non Current	369	347	21	
Derivative Liability	49	42	7	
Other Liabilities	85	89	(4)	
Total Deferred Credits and Other Liabilities	1,612	1,598	14	
Equity	2,043	2,042	1	
Total Liabilities and Equity	**$ 5,763**	**$ 5,829**	**$ (66)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

Balance Sheet - KU

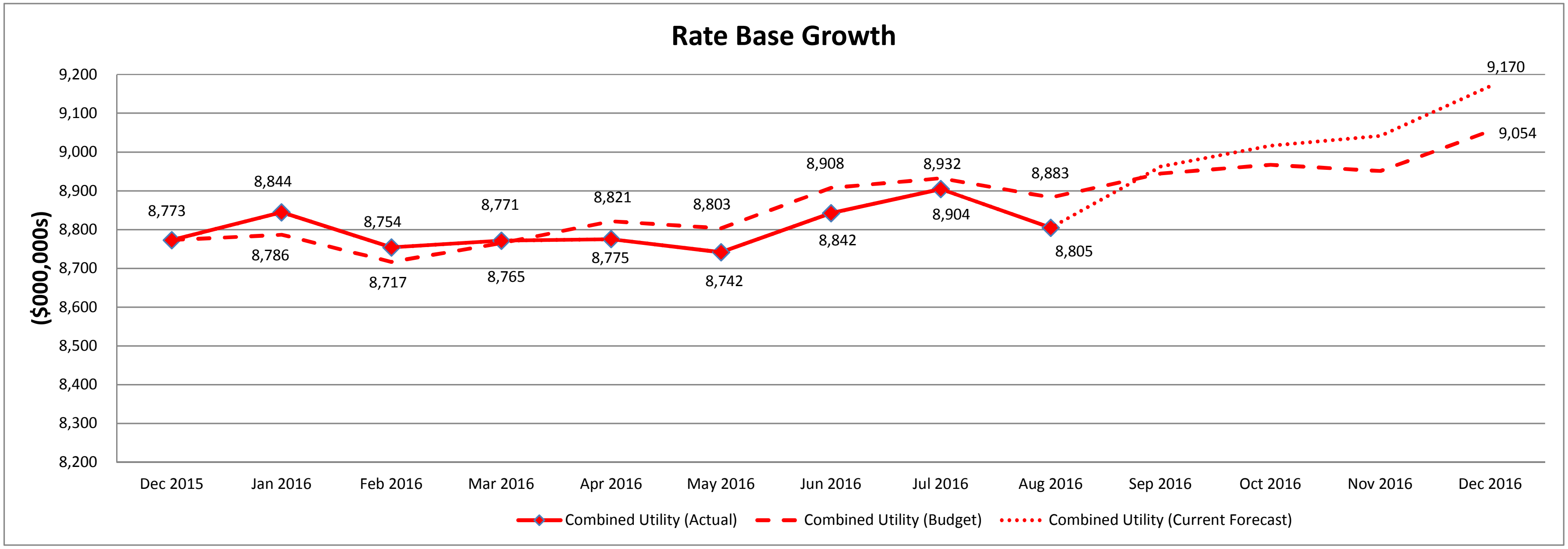
August 2016

($ Millions)

	8/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 10	$ 9	$ 1	
Accounts Receivable (Trade)	241	231	11	
Inventory	153	143	10	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	13	40	(27)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	55	22	33	Primarily due to increase in notes receivable from affiliate company for funds provided in money pool.
Total Current Assets	472	445	27	
Property, Plant, and Equipment	6,634	6,701	(66)	
Intangible Assets	13	8	5	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	333	322	11	
Goodwill	-	-	-	
Other Long-term Assets	55	54	1	
Total Assets	**$ 7,507**	**$ 7,529**	**$ (23)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 116	$ 128	$ (12)	Due to decrease in accruals and lower coal purchases, partially offset by an increase in contract retainage due to reclassification from non-current to current and increase in natural gas purchases.
Dividends Payable to Affiliated Companies	84	36	48	Larger dividend declared to maintain balanced capital structure.
Customer Deposits	28	26	2	
Derivative Liability	-	-	-	
Accrued Taxes	59	73	(14)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1.
Regulatory Liabilities Current	19	17	3	
Other Current Liabilities	98	93	4	
Total Current Liabilities	404	373	31	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,324	2,324	0	
Total Debt	2,324	2,324	0	
Deferred Tax Liabilities	1,118	1,127	(10)	
Investment Tax Credit	96	92	4	
Accum Provision for Pension & Related Benefits	41	38	3	
Asset Retirement Obligation	330	347	(16)	
Regulatory Liabilities Non Current	459	438	21	
Derivative Liability	-	-	-	
Other Liabilities	46	56	(9)	
Total Deferred Credits and Other Liabilities	2,090	2,098	(8)	
Equity	2,688	2,734	(46)	
Total Liabilities and Equity	**$ 7,507**	**$ 7,529**	**$ (23)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.



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Performance Report

September 2016

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Kentucky Regulated Dashboard — September 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.39	1.17	1.13	1.11	1.38	1.22
Employee lost-time incidents	0	0	3	7	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,892	2,789	25,960	26,771	34,153	34,964
Utility EFOR	4.5%	5.7%	6.2%	5.7%	N/A	5.7%
Utility EAF	92.8%	85.4%	85.7%	85.4%	N/A	82.3%
Steam Fleet Commercial Availability	95.9%	92.8%	93.9%	92.8%	N/A	92.8%
Combined SAIFI	0.06	0.08	0.83	0.81	N/A	1.03
Combined SAIDI (minutes)	5.58	6.55	81.04	74.64	N/A	94.09
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	858	882	8,304	8,471	10,756	10,847
Commercial	724	640	6,111	5,918	8,001	7,793
Industrial	761	793	7,065	7,576	9,442	10,089
Municipals	161	155	1,448	1,451	1,877	1,886
Other	267	220	2,165	2,114	2,841	2,798
Off-System Sales	25	8	149	295	173	322
Total	2,796	2,698	25,242	25,825	33,090	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.63%			
Commercial			2.20%			
Industrial			-5.31%			
Municipal			0.31%			
Other			0.14%			
Total			-1.91%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$155	$158	$1,411	$1,429	$1,849	$1,870
Gas Margins	9	9	122	126	170	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$60	$80	$547	$748	$872	$955
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$54	$61	$522	$549	$708	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,484	3,596	3,484	3,596	3,567	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	3	15	N/A	16
NERC Possible Violations[3]	4	1	5	7	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[4]	9.8%	10.0%	9.8%

Variance Explanations

• YTD lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $19 million, $4 million lower gas margins and $4 million lower retail rate mechanism revenue. This was partially offset by $5 million lower production costs and other margin components.

• Current month lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance and outage expenses and outside services.

• YTD lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management, uncollectible accounts and outside services.

• Current month capital expenditures were lower, primarily due to lower than budgeted ECR spending on CCR projects.

• YTD capital expenditures were lower, primarily due to lower level of ECR spending on Environmental Air projects at Mill Creek, permitting delays related to CCR projects at Trimble County and timing related to the Cane Run Ash Pond closure and Blackstart projects.

Major Developments

• LKE was recognized as one of the Healthiest 100 Workplaces in the U.S. at the Corporate Wellness Conference in Washington D.C. The winners were honored for their commitment to employee health and exceptional corporate wellness programs. There were over 5,000 applicants and LKE [53rd] and Great River Energy [16th], a cooperative in Minnesota, were the only utilities to receive the award. This prestigious award follows several other wellness awards received earlier this year – a Healthiest Employer Award from *Business First* [a weekly business journal for Greater Louisville], and two awards from both the American Heart Association, and the Worksite Wellness Council of Louisville.

• LKE was also named a top utility in economic development by *Site Selection* magazine. As of September 30, 2016, LKE's efforts have assisted nearly 80 companies create approximately 5,310 jobs and invest over $1 billion in facility location or expansion projects in its service territories.

• LG&E recently priced $125 million of pollution control bonds at a variable rate of 0.90 percent with weekly reset. There was strong demand for the bonds from investors.

• LKE received the operating permit for Brown station's dry landfill allowing CCR material to be placed in the Phase 1 location.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms.

(3) The possible violation issues are believed to be minimal risk.

(4) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated

September 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 244	$ 249	$ (5)	Due to lower FAC revenues based on the lower fuel costs shown below along with lower residential and industrial revenues, including the loss of [redacted]) as a customer.
Gas Revenues	14	13	0	
Total Revenues	258	262	(4)	
Cost of Sales:				
Fuel Electric Costs	69	70	2	Primarily due to lower commodity costs.
Gas Supply Expenses	4	4	(0)	
Purchased Power	5	5	(0)	
Other Electric Cost	16	16	0	
Total Cost of Sales	93	94	1	
Gross Margin:				
Electric Margin	155	158	(3)	
Gas Margin	9	9	(0)	
Total Gross Margin	164	168	(3)	
Operating Expenses:				
O&M	54	61	7	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management, uncollectible accounts and outside services.
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	88	96	8	
Other income (expense)	(4)	(0)	(3)	
EBIT	73	72	2	
Interest Expense	18	18	(0)	
Income from Ongoing Operations before income taxes	55	53	1	
Income Tax Expense	21	20	(1)	
Net Income (loss) from ongoing operations	**34**	**33**	**$ 0**	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 34	$ 33	$ 0	
KY Regulated Financing Costs	(3)	(2)	(0)	
KY Regulated Net Income	$ 31	$ 31	$ 0	
Earnings Per Share - Ongoing	$ 0.05	$ 0.05	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

September 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,180	$ 2,300	$ (120)	Due to lower volumes driven by unfavorable weather, FAC revenue from lower fuel costs (see below), and industrial volumes.
Gas Revenues	205	233	(28)	See Gas Supply Expenses explanation below.
Total Revenues	2,385	2,533	(148)	
Cost of Sales:				
Fuel Electric Costs	609	691	82	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	83	107	24	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	42	44	2	
Other Electric Cost	118	136	18	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	853	978	125	
Gross Margin:				
Electric Margin	1,411	1,429	(19)	Lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $19 million and $4 million lower retail rate mechanism revenue. This was partially offset by $5 million lower production costs and other margin components.
Gas Margin	122	126	(4)	
Total Gross Margin	1,533	1,555	(22)	
Operating Expenses:				
O&M	522	548	27	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management, uncollectible accounts and outside services.
Depreciation & Amortization	261	268	7	Lower depreciation primarily due to project completion and spending updates as well as higher level of retirements this year.
Taxes, Other than Income	42	42	(0)	
Total Operating Expenses	825	859	34	
Other income (expense)	(9)	(5)	(4)	
EBIT	699	691	8	
Interest Expense	159	163	3	
Income from Ongoing Operations before income taxes	539	528	11	
Income Tax Expense	202	202	(1)	
Net Income (loss) from ongoing operations	**337**	**326**	**$ 10**	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 337	$ 326	$ 11	
KY Regulated Financing Costs	(23)	$ (22)	(0)	
KY Regulated Net Income	$ 314	$ 304	$ 11	
Earnings Per Share - Ongoing	$ 0.46	$ 0.45	$ 0.01	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E

September 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 875	$ 908	$ (33)	Due to lower volumes driven by unfavorable weather, lower FAC revenue from lower fuel costs (see below), and lower industrial volumes.
Gas Revenues	205	233	(28)	See Gas Supply Expenses explanation below.
Total Revenues	1,080	1,141	(61)	
Cost of Sales:				
Fuel Electric Costs	237	259	22	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	83	107	24	Due to lower gas usage (mild weather) and prices
Purchased Power	39	46	7	
Other Electric Cost	46	55	9	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	405	466	61	
Gross Margin:				
Electric Margin	553	549	4	
Gas Margin	122	126	(4)	
Total Gross Margin	675	675	0	
Operating Expenses:				
O&M	232	247	15	Lower O&M primarily due to timing of plant maintenance and outages, vegetation management, storm restoration and labor and burden savings.
Depreciation & Amortization	106	109	3	
Taxes, Other than Income	21	21	(0)	
Total Operating Expenses	359	377	18	
Other income (expense)	(5)	(2)	(3)	
EBIT	311	296	15	
Interest Expense	53	53	1	
Income from Ongoing Operations before income taxes	258	243	16	
Income Tax Expense	99	93	(6)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**159**	**150**	**$ 10**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

September 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,334	$ 1,438	$ (104)	Due to lower volumes driven by unfavorable weather and by the loss of [redacted]) as a customer.
Gas Revenues	-	-	-	
Total Revenues	1,334	1,438	(104)	
Cost of Sales:				
Fuel Electric Costs	375	437	62	Primarily due to decreased generation as a result of mild weather and lower commodity costs.
Gas Supply Expenses	-	-	-	
Purchased Power	30	40	10	Lower purchased power due to mild weather.
Other Electric Cost	72	81	9	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	476	558	82	
Gross Margin:				
Electric Margin	858	880	(23)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	858	880	(23)	
Operating Expenses:				
O&M	271	285	15	Lower O&M primarily due to timing of plant maintenance, lower storm restoration, vegetation management and outside services along with labor and burden savings.
Depreciation & Amortization	155	159	4	
Taxes, Other than Income	21	21	0	
Total Operating Expenses	447	465	19	
Other income (expense)	(3)	(3)	(0)	
EBIT	407	412	(5)	
Interest Expense	72	73	2	
Income from Ongoing Operations before income taxes	336	339	(3)	
Income Tax Expense	128	129	1	
Net Income (loss) from ongoing operations	**208**	**210**	**$ (2)**	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Budget - LKE Consolidated — September 2016

($ Millions)

	Full Year			
	Q3 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,871	$ 3,011	$ (140)	Due to lower volumes driven by unfavorable weather, along with lower fuel costs as shown below. In addition, an updated load forecast with lower volumes was included for the remainder of the year.
Gas Revenues	300	330	(30)	See Gas Supply Expenses explanation below.
Total Revenues	3,172	3,342	(170)	
Cost of Sales:				
Fuel Electric Costs	805	901	97	Primarily due to decreased generation as a result of mild weather and to lower commodity costs.
Gas Supply Expenses	131	155	25	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	56	58	1	
Other Electric Cost	161	182	21	Due to lower ECR expense (using less PAC and NALCO), mild weather and scrubber reactant expense.
Total Cost of Sales	1,153	1,296	144	
Gross Margin:				
Electric Margin	1,849	1,870	(21)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	170	175	(5)	See Gas Supply Expenses explanation above.
Total Gross Margin	2,019	2,045	(26)	
Operating Expenses:				
O&M	708	731	23	Due to lower labor and burden costs, maintenance & outage savings, lower storm restoration & vegetation management, A&G expenses and outside services.
Depreciation & Amortization	349	359	10	Due to increased auto-retirements not captured in the budget, along with revised in-service dates and final spend on completed projects.
Taxes, Other than Income	57	56	(0)	
Total Operating Expenses	1,114	1,146	32	
Other income (expense)	(11)	(7)	(4)	
EBIT	894	892	2	
Interest Expense	213	217	5	Lower interest due to lower interest rates.
Income from Ongoing Operations before income taxes	681	675	7	
Income Tax Expense	256	257	1	
Net Income (loss) from ongoing operations	**425**	**417**	**$ 8**	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 425	$ 417	$ 8	
KY Regulated Financing Costs	(30)	$ (30)	(0)	
KY Regulated Net Income	$ 395	$ 387	$ 8	
Earnings Per Share - Ongoing	$ 0.57	$ 0.57	$ (0.00)	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD

($ Millions)

September 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	80	79	1
Demand	47	50	(3)
Base Service Charge	14	14	(0)
Rate Mechanisms	16	17	(2)
Other Rev/Cost of Sales	(1)	(1)	(0)
Other Margin Items	(1)	(2)	0
	155	158	(3)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	36	34	1
Demand	16	17	(1)
Base Service Charge	6	6	(0)
Rate Mechanisms	8	9	(1)
Other Rev/Cost of Sales	(0)	(0)	0
Other Margin Items	(2)	(2)	0
	63	63	0

KU Electric Margin

	Actual	Budget	Variance
Base Energy	45	45	(0)
Demand	31	34	(2)
Base Service Charge	8	8	0
Rate Mechanisms	7	8	(1)
Other Rev/Cost of Sales	(0)	(0)	(0)
Other Margin Items	0	0	0
	92	95	(3)

LKE Base Energy Price/Vol Variance

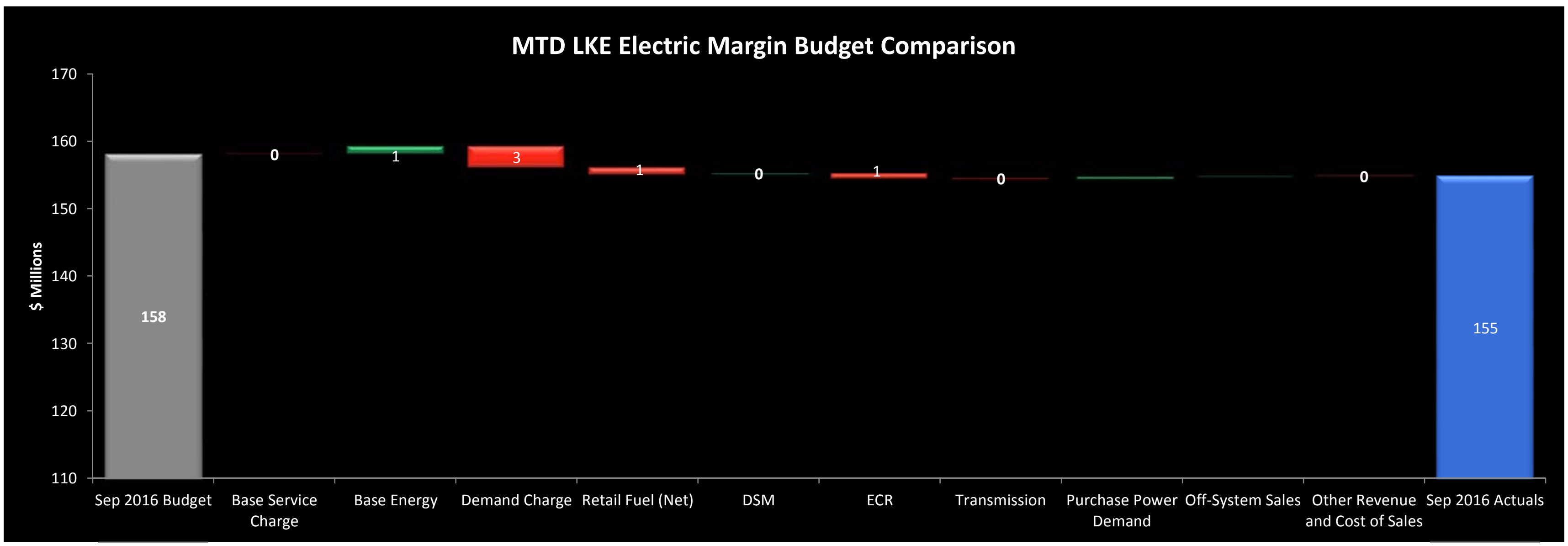
	Volume	Price	Total Variance
Residential	(1)	0	(1)
Commercial	3	(1)	2
Industrial	(0)	0	(0)
Public Authority	1	(0)	1
Street Lights	(0)	0	0
Municipals	0	(0)	(0)
Other	0	0	0
	2	(1)	1

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(0)	0	(0)
Commercial	2	(1)	1
Industrial	(0)	0	(0)
Public Authority	1	(0)	0
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	2	(1)	1

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(1)	0	(1)
Commercial	1	(0)	0
Industrial	(0)	0	0
Public Authority	0	(0)	0
Street Lights	(0)	0	0
Municipals	0	(0)	(0)
Other	0	0	0
	0	(0)	(0)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Electric Gross Margin Analysis - YTD
($ Millions)

September 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	746	755	(10)
Demand	416	426	(10)
Base Service Charge	123	124	(0)
Rate Mechanisms	142	146	(4)
Other Rev/Cost of Sales	(3)	(6)	3
Other Margin Items	(13)	(15)	2
	1411	1429	(19)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	307	306	1
Demand	137	137	1
Base Service Charge	50	51	(0)
Rate Mechanisms	73	74	(1)
Other Rev/Cost of Sales	(0)	(2)	1
Other Margin Items	(14)	(16)	2
	553	549	4

KU Electric Margin

	Actual	Budget	Variance
Base Energy	439	450	(11)
Demand	278	289	(11)
Base Service Charge	73	73	0
Rate Mechanisms	68	72	(3)
Other Rev/Cost of Sales	(3)	(4)	1
Other Margin Items	1	1	0
	858	880	(23)

LKE Base Energy Price/Vol Variance

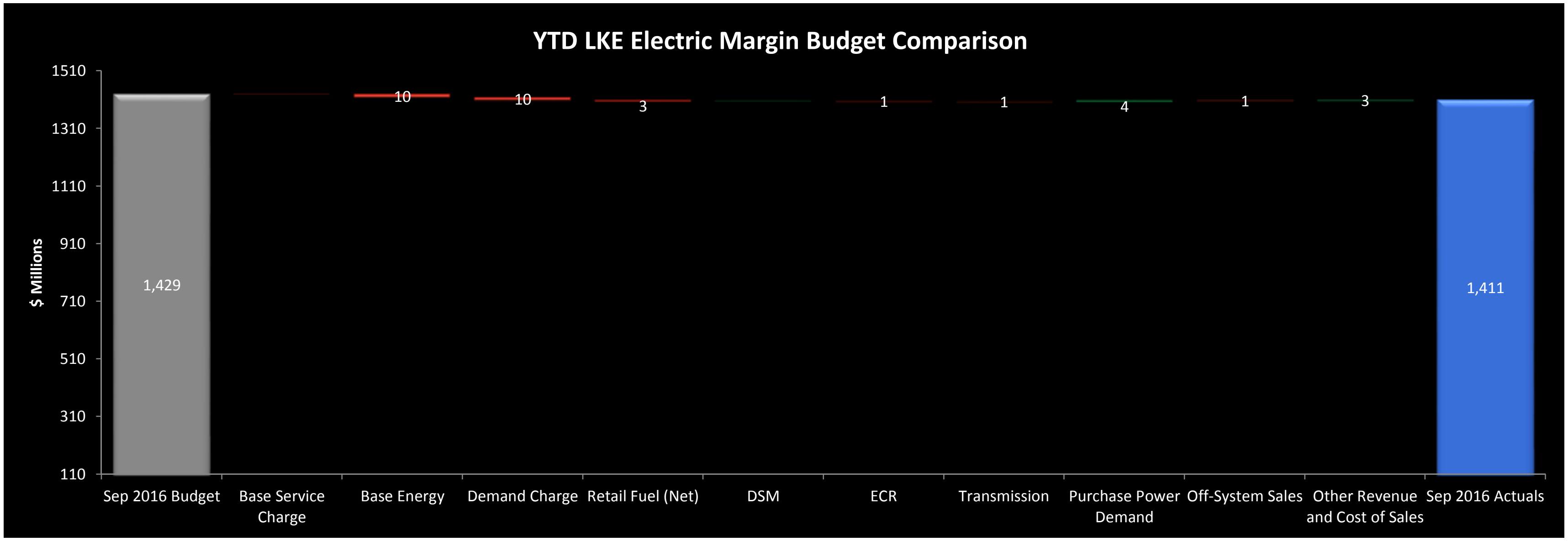
	Volume	Price	Total Variance
Residential	(9)	5	(4)
Commercial	6	(7)	(1)
Industrial	(4)	2	(3)
Public Authority	1	(1)	0
Street Lights	(1)	1	(0)
Municipals	(0)	(2)	(2)
Other	0	0	0
	(7)	(2)	(10)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(2)	2	(0)
Commercial	6	(4)	1
Industrial	(2)	1	(2)
Public Authority	1	0	1
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	2	(1)	1

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(7)	3	(4)
Commercial	0	(3)	(3)
Industrial	(2)	1	(1)
Public Authority	0	(1)	(1)
Street Lights	(2)	1	(0)
Municipals	(0)	(2)	(2)
Other	0	0	0
	(10)	(1)	(11)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin — September 2016

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**(0)**	**$ 47**	**$ 47**		**$ 0**
Gas Supply Costs								
Gas Supply Costs	(3)	(3)	$ (1)		$ (75)	$ (98)	$ 22	
GSC Revenue	4	3	$ 1		$ 76	$ 98	$ (22)	
Net Gas Supply Costs				**0**				**$ 1**
Retail Gas (a)	**3**	**3**		**(0)**	**$ 59**	**$ 66**		**$ (7)**
Wholesale Gas (a)	**0**	**-**		**0**	**$ 0**	**$ -**		**$ 0**
DSM	**0**	**0**		**(0)**	**$ 0**	**$ 1**		**$ (1)**
GLT	**1**	**1**		**0**	**$ 11**	**$ 11**		**$ 0**
WNA	**(0)**	**-**		**(0)**	**$ 3**	**$ -**		**$ 3**
Other Margin	**0**	**0**		**(0)**	**$ 1**	**$ 1**		**$ (0)**
Gas Margin Variance				**$ (0)**				**$ (4)**

(a) Retail and wholesale gas sales - excludes GSC

MTD

	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	364,636	$ 2.87	$ 1	421,592	$ 2.87	($0.2)	($0.2)	($0.0)
Commercial	1	253,274	1.99	1	264,989	2.10	($0.1)	($0.0)	($0.0)
Industrial	0	70,567	1.72	0	91,876	2.09	($0.1)	($0.0)	($0.0)
Public Authority	0	27,130	1.83	0	47,081	1.93	($0.0)	($0.0)	($0.0)
Transportation	0	976,898	0.49	0	846,239	0.53	$0.0	$0.1	($0.0)
Interdepartmental	0	50,965	6.24	0	84,610	3.56	$0.0	($0.1)	$0.1
Ultimate Consumer	$ 3	1,743,470	$ 1.44	$ 3	1,756,388	$ 1.59	($0.3)	($0.3)	$0.0

YTD

	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 35	12,342,758	$ 2.87	$ 41	14,363,021	$ 2.87	($6)	$ (6)	$ (0)
Commercial	12	5,926,766	2.09	14	6,384,813	2.13	($1)	$ (1)	$ (0)
Industrial	2	830,599	1.97	2	1,032,625	2.12	($1)	$ (0)	$ (0)
Public Authority	2	806,611	2.04	2	1,016,271	2.07	($0)	$ (0)	$ (0)
Transportation	5	10,240,667	0.50	4	8,780,430	0.50	$1	$1	$0
Interdepartmental	3	267,305	10.41	3	996,490	2.73	$0	($2)	$2
Ultimate Consumer	$ 59	30,414,706	$ 1.94	$ 66	32,573,650	$ 2.03	($7)	($9)	$2

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	16	2	1	(0)	0	1	1
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	3	0	0	0	0	0	(0)
Energy Supply and Analysis	1	1	0	0	(0)	0	0	0
Generation Services	1	1	0	0	(0)	0	(0)	0
Electric Distribution	6	6	(0)	0	(0)	(0)	0	(0)
Gas Distribution	3	3	0	0	0	(0)	0	0
Safety and Technical Training	0	0	(0)	(0)	(0)	(0)	(0)	0
Customer Services	7	8	1	0	(0)	0	(0)	1
Chief Operations Officer	**34**	**38**	**4**	**2**	**(0)**	**0**	**1**	**2**
General Counsel	3	4	1	0	0	1	0	0
Human Resources	1	1	0	0	-	(0)	0	0
General Counsel & HR	**3**	**4**	**1**	**0**	**0**	**1**	**0**	**0**
Audit Services	0	0	0	0	-	(0)	0	0
Controller	1	1	0	0	-	0	0	0
Information Technology	4	5	1	0	0	0	0	0
Supply Chain	0	0	0	0	-	0	0	0
Treasurer	1	1	0	(0)	-	(0)	(0)	0
State Regulation and Rates	0	0	(0)	0	-	(0)	(0)	0
Chief Financial Officer	**7**	**8**	**1**	**0**	**0**	**0**	**0**	**0**
Corporate	**10**	**11**	**1**	**1**	**(0)**	**0**	**(0)**	**(0)**
O&M Total MTD	**54**	**61**	**7**	**3**	**(0)**	**1**	**1**	**2**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	143	150	8	3	(2)	3	7	(4)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	22	23	2	0	0	0	0	1
Energy Supply and Analysis	6	7	0	0	(0)	0	0	0
Generation Services	10	11	1	0	(0)	(0)	(0)	1
Electric Distribution	53	56	3	(1)	4	(1)	0	1
Gas Distribution	25	25	0	0	(1)	1	0	(0)
Safety and Technical Training	4	4	0	0	(0)	(0)	0	0
Customer Services	62	65	4	1	0	1	0	2
Chief Operations Officer	**325**	**342**	**17**	**5**	**1**	**4**	**8**	**1**
General Counsel	23	25	2	0	0	1	0	1
Human Resources	5	5	1	0	(0)	0	0	0
General Counsel & HR	**27**	**30**	**3**	**0**	**0**	**1**	**0**	**1**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	7	7	0	(0)	-	0	0	0
Information Technology	41	45	4	2	(0)	1	0	0
Supply Chain	3	3	(0)	(0)	(0)	0	0	0
Treasurer	8	8	0	(0)	-	(0)	(0)	1
State Regulation and Rates	3	3	(0)	0	-	0	(0)	0
Chief Financial Officer	**64**	**68**	**4**	**2**	**(0)**	**1**	**0**	**1**
Corporate	**106**	**109**	**3**	**2**	**(2)**	**2**	**(1)**	**1**
O&M Total YTD	**522**	**549**	**27**	**9**	**(1)**	**8**	**8**	**4**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	200	206	6	3	(3)	3	5	(1)
Project Engineering	0	1	0	0	-	(0)	(0)	0
Transmission	30	30	1	0	(0)	(0)	0	1
Energy Supply and Analysis	9	9	0	0	(0)	(0)	0	0
Generation Services	15	15	0	(0)	(0)	0	(0)	1
Electric Distribution	69	73	4	(2)	3	(0)	0	2
Gas Distribution	34	34	(0)	0	(1)	0	(0)	0
Safety and Technical Training	5	5	0	(0)	(0)	0	0	(0)
Customer Services	84	87	3	1	(0)	1	0	2
Chief Operations Officer	**446**	**459**	**13**	**2**	**(1)**	**3**	**5**	**4**
General Counsel	31	32	1	(0)	0	0	0	1
Human Resources	7	7	0	0	(0)	0	0	0
General Counsel & HR	**38**	**39**	**1**	**0**	**0**	**0**	**0**	**1**
Audit Services	2	2	0	0	-	(0)	0	0
Controller	10	10	0	(0)	-	0	0	0
Information Technology	57	60	3	3	(0)	0	0	0
Supply Chain	4	4	(0)	(0)	(0)	0	0	(0)
Treasurer	11	11	0	(0)	-	(0)	(0)	1
State Regulation and Rates	4	3	(0)	(0)	-	0	(0)	0
Chief Financial Officer	**87**	**90**	**3**	**2**	**(0)**	**0**	**0**	**1**
Corporate	**138**	**144**	**6**	**0**	**(1)**	**4**	**(0)**	**3**
O&M Total Full Year	**708**	**731**	**23**	**5**	**(3)**	**8**	**5**	**9**

Note: Schedules may not sum due to rounding.

Financing Activities — September 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.8	$ (0.0)	$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	(0.0)	898.9	923.8	24.9
Ave Bal	**$ 923.8**	**$ 923.8**	**$ (0.0)**	**$ 911.3**	**$ 923.8**	**$ 12.5**
Interest Exp	**$ 9.6**	**$ 10.4**	**$ 0.9**	**$ 12.7**	**$ 13.9**	**$ 1.2**
Rate	**1.36%**	**1.48%**	**0.12%**	**1.37%**	**1.48%**	**0.10%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 132.9**	**$ 132.9**	**$ 0.0**	**$ 175.3**	**$ 175.3**	**$ -**
Rate	**4.15%**	**4.15%**	**0.00%**	**4.10%**	**4.10%**	**0.00%**
Short-term Debt						
Beg Bal	$ 318.9	$ 216.4	$ (102.5)	$ 451.8	$ 347.7	$ (104.1)
End Bal	272.8	295.5	22.7	509.7	347.7	(162.0)
Ave Bal	**$ 295.9**	**$ 255.9**	**$ (39.9)**	**$ 480.8**	**$ 347.7**	**$ (133.1)**
Interest Exp	**$ 2.8**	**$ 3.5**	**$ 0.6**	**$ 5.0**	**$ 4.8**	**$ (0.2)**
Rate	**1.26%**	**1.79%**	**0.53%**	**1.02%**	**1.35%**	**0.33%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (42.5)	$ 3.8	$ (42.2)	$ (39.6)	$ 2.6
End Bal	(44.8)	(41.8)	3.0	(43.2)	(39.6)	3.6
Ave Bal	**$ (45.6)**	**$ (42.1)**	**$ 3.4**	**$ (42.7)**	**$ (39.6)**	**$ 3.1**
Total End Bal	**$ 5,361.8**	**$ 5,387.5**	**$ 25.7**	**$ 5,575.3**	**$ 5,441.9**	**$ (133.5)**
Total Average Bal	**$ 5,384.1**	**$ 5,347.6**	**$ (36.5)**	**$ 5,559.4**	**$ 5,441.9**	**$ (117.5)**
Total Expense Excl I/C [1]	**$ 159.4**	**$ 162.9**	**$ 3.5**	**$ 212.7**	**$ 217.2**	**$ 4.5**
Rate	**3.86%**	**3.97%**	**0.11%**	**3.73%**	**3.90%**	**0.16%**

[1] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[2]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 138		$ 162
LG&E	500	128		372
KU	598	7	$ 198	393
TOTAL	$ 1,398	$ 273	$ 198	$ 927

[2] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	19%	19%	28%	28%	26%	26%
CFO pre-WC + Interest / Interest	5.8	5.7	8.1	8.1	7.5	7.5
CFO pre-WC - Dividends / Debt	16%	19%	28%	28%	17%	26%
Debt to Capitalization[2]	47%	47%	38%	39%	38%	38%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	20%	28%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.8	5.7	7.9	7.8	7.7	7.2
CFO pre-WC - Dividends / Debt	19%	20%	28%	29%	28%	26%
Debt to Capitalization[2]	45%	45%	38%	37%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015 Issuer	Senior Unsecured Moody's	Senior Secured Moody's	Commercial Paper Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — September 2016

($ Millions)

	9/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 11	$ 14	$ (3)	
Accounts Receivable (Trade)	394	374	20	
Inventory	292	272	20	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	18	64	(46)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	42	45	(3)	
Total Current Assets	757	769	(12)	
Property, Plant, and Equipment	11,477	11,784	(307)	
Intangible Assets	103	91	12	Amortization related to software classified as intangibles in budget versus PP&E in actuals.
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	774	746	28	
Goodwill	997	997	-	
Other Long-term Assets	78	83	(4)	
Total Assets	**$ 14,187**	**$ 14,470**	**$ (283)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 225	$ 275	$ (50)	Primarily due to decrease in accruals partially offset by an increase in natural gas purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	55	52	3	
Derivative Liability	6	5	1	
Accrued Taxes	49	102	(53)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. In Q3, NOL addition and utilization were actualized causing accrued taxes to decrease by $16 mil ($-13 mil LGE, $-10 mil KU, +$7 mil LKE Other).
Regulatory Liabilities Current	26	30	(4)	
Other Current Liabilities	238	223	15	
Total Current Liabilities	599	687	(88)	
Debt - Affiliated Company	538	400	138	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016 and quarterly pay off of any cash needed for operations on non quarter months. The forecast does not assume any pay off of the short term debt with affiliate. Prior years federal and state tax settlement generated $10.5 mil in cash at LKE Other.
Debt [1]	4,824	4,988	(164)	
Total Debt	5,362	5,388	(26)	
Deferred Tax Liabilities	1,673	1,641	33	
Investment Tax Credit	132	125	7	
Accum Provision for Pension & Related Benefits	242	269	(26)	Primarily due to additional pension contribution partially offset by roll forward of funded status, both of which are not included in budgeted amounts.
Asset Retirement Obligation	368	502	(134)	Primarily due to ARO revaluation to reflect updates in the estimated cash flows for ash and environmental ponds as a result of further engineering refinements to the design.
Regulatory Liabilities Non Current	911	866	45	
Derivative Liability	48	42	6	
Other Liabilities	180	193	(14)	
Total Deferred Credits and Other Liabilities	3,554	3,638	(84)	
Equity	4,672	4,758	(86)	
Total Liabilities and Equity	**$ 14,187**	**$ 14,470**	**$ (283)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

September 2016

($ Millions)

	9/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 4	$ 5	$ (1)	
Accounts Receivable (Trade)	168	159	9	
Inventory	140	129	12	Higher actual due to lower than expected usage and higher than budgeted inventory levels.
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	6	25	(18)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	46	34	12	Due to higher accounts receivable from affiliate related to charges for Trimble County CCR projects, inventory and fuel.
Total Current Assets	364	352	13	
Property, Plant, and Equipment	4,920	5,060	(140)	
Intangible Assets	6	(1)	7	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	436	418	18	
Goodwill	-	-	-	
Other Long-term Assets	21	19	2	
Total Assets	**$ 5,748**	**$ 5,848**	**$ (101)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 152	$ 187	$ (35)	Primarily due to decrease in accruals partially offset by an increase in natural gas purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	23	53	$ (30)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. Rebalancing NOL Addition in Q3 for the change in summer months income caused a $9 mil decrease in Accrued Taxes.
Regulatory Liabilities Current	6	13	(6)	
Other Current Liabilities	98	73	25	Primarily due to difference in the timing of interest payments assumed in the budget versus actual related to September 2015 bonds issuances and reclassification of ARO liability from long-term to current.
Total Current Liabilities	312	356	(44)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	1,770	1,810	(39)	
Total Debt	1,770	1,810	(39)	
Deferred Tax Liabilities	944	924	20	
Investment Tax Credit	37	34	3	
Accum Provision for Pension & Related Benefits	19	40	(21)	Primarily due to additional pension contribution partially offset by roll forward of funded status, both of which are not included in budgeted amounts.
Asset Retirement Obligation	107	154	(47)	Primarily due to ARO revaluation to reflect updates in the estimated cash flows for ash and environmental ponds as a result of further engineering refinements to the design and reclassification of a portion of ARO liability from long-term to current.
Regulatory Liabilities Non Current	368	345	23	
Derivative Liability	48	42	6	
Other Liabilities	85	88	(4)	
Total Deferred Credits and Other Liabilities	1,606	1,626	(20)	
Equity	2,060	2,057	3	
Total Liabilities and Equity	**$ 5,748**	**$ 5,848**	**$ (101)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

Balance Sheet - KU

September 2016

($ Millions)

	9/30/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 7	$ 5	$ 2	
Accounts Receivable (Trade)	225	213	12	
Inventory	151	143	8	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	12	39	(27)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	21	22	(1)	
Total Current Assets	417	423	(6)	
Property, Plant, and Equipment	6,549	6,716	(168)	
Intangible Assets	13	7	5	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	335	325	10	
Goodwill	-	-	-	
Other Long-term Assets	55	54	1	
Total Assets	**$ 7,368**	**$ 7,526**	**$ (157)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 108	$ 128	$ (20)	Due to decrease in accruals and lower coal purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	28	26	2	
Derivative Liability	-	-	-	
Accrued Taxes	23	47	(24)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. IN Q3, KU had more NOL utilization than budget causing Accrued taxes to decrease by $7 mil.
Regulatory Liabilities Current	19	17	3	
Other Current Liabilities	87	92	(5)	
Total Current Liabilities	266	311	(44)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,331	2,377	(46)	
Total Debt	2,331	2,377	(46)	
Deferred Tax Liabilities	1,166	1,168	(2)	
Investment Tax Credit	96	92	4	
Accum Provision for Pension & Related Benefits	34	38	(5)	
Asset Retirement Obligation	261	348	(87)	Primarily due to ARO revaluation to reflect updates in the estimated cash flows for ash and environmental ponds as a result of further engineering refinements to the design.
Regulatory Liabilities Non Current	459	437	23	
Derivative Liability	-	-	-	
Other Liabilities	46	55	(8)	
Total Deferred Credits and Other Liabilities	2,061	2,137	(76)	
Equity	2,710	2,701	8	
Total Liabilities and Equity	**$ 7,368**	**$ 7,526**	**$ (157)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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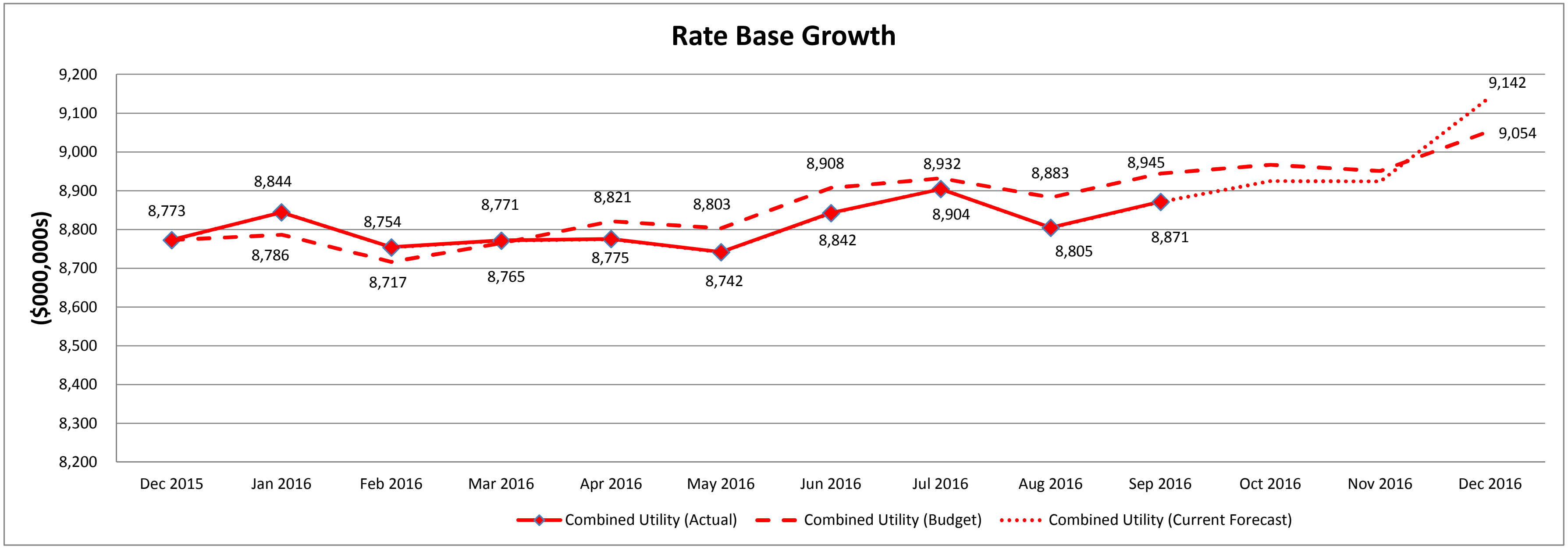
Blake


Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
Dec 2015
Jan 2016
Feb 2016
Mar 2016
Apr 2016
May 2016
Jun 2016
Jul 2016
Aug 2016
Sep 2016
Oct 2016
Nov 2016
Dec 2016
8,773
8,844
8,754
8,771
8,821
8,803
8,908
8,932
8,883
8,945
9,142
9,054
8,786
8,717
8,765
8,775
8,742
8,842
8,904
8,805
8,871
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

KU and LG&E Combined
Reconciliation of Allowed Return to
Net Income Last Rate Case Regulatory Return
and ROE from Ongoing Operations

Allowed Return (1)		10.0%	
Adjustments (net tax):			
Change in capitalization - non mechanism	0.1%		
Change in ROE from average mechanism rate base growth	0.0%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.1%		Lower interest rates
Change in margins	-0.8%		Lower sales
Change in allowed expenses	0.5%		Lower depreciation expense
		-0.2%	
Actual Regulated ROE		9.8%	

(1) Based on the most recent base rate filings with test years ending 6/30/16 KPSC, 12/31/15 FERC, 12/31/14 VA.

Performance Report

October 2016

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Kentucky Regulated Dashboard — October 2016

	Current Month		YTD		Full Year	
Safety[1]	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.74	0.82	1.09	1.07	1.38	1.22
Employee lost-time incidents	0	1	3	8	9	8
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,511	2,549	28,471	29,319	34,115	34,964
Utility EFOR	2.9%	5.7%	5.9%	5.7%	N/A	5.7%
Utility EAF	72.3%	83.6%	84.3%	83.6%	N/A	82.3%
Steam Fleet Commercial Availability	89.8%	92.8%	93.5%	92.8%	N/A	92.8%
Combined SAIFI	0.07	0.09	0.91	0.90	N/A	1.03
Combined SAIDI (minutes)	5.72	7.51	86.76	82.15	N/A	94.09
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	615	679	8,919	9,150	10,735	10,847
Commercial	633	617	6,744	6,535	8,008	7,793
Industrial	776	822	7,841	8,398	9,433	10,089
Municipals	135	139	1,583	1,590	1,874	1,886
Other	236	221	2,401	2,335	2,856	2,798
Off-System Sales	35	2	184	297	207	322
Total	2,430	2,480	27,672	28,305	33,114	33,735
Weather-Normalized Sales Growth			**TTM**			
Residential			-2.39%			
Commercial			2.86%			
Industrial			-5.40%			
Municipal			0.37%			
Other			0.56%			
Total			-1.66%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$136	$142	$1,547	$1,571	$1,849	$1,870
Gas Margins	11	11	133	137	170	175
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$64	$78	$611	$826	$872	$955
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$57	$65	$579	$614	$708	$731
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,498	3,596	3,498	3,596	3,565	3,600
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	3	15	N/A	16
NERC Possible Violations[3]	0	0	5	7	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[4]	9.9%	10.0%	9.8%

Variance Explanations

• Current month lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $4 million and $2 million in lower gas margins and retail rate mechanism revenue.

• YTD lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $24 million, $4 million lower gas margins and $4 million lower retail rate mechanism revenue. This was partially offset by $5 million lower production costs and other margin components.

• Current month lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance and outage expenses and outside services.

• YTD lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management, uncollectible accounts and outside services.

• Current month capital expenditures were lower, primarily due to lower than budgeted ECR spending on CCR projects.

• YTD capital expenditures were lower, primarily due to lower level of ECR spending on Environmental Air projects at Mill Creek, permitting delays related to CCR projects at Trimble County and timing related to the Cane Run Ash Pond closure and Blackstart projects.

Major Developments

• On October 21, LG&E and KU filed "Notices of Intent" with the KPSC, indicating that the Company plans to file a request for base rate increases on November 23. A related press release was issued on November 1 and media coverage has been relatively fair and straight forward. The Company intends to seek increases in annual base rates of $94 million (8.5%) for LG&E Electric, $14 million (4.2%) for LG&E Gas, and $103 million (6.4%) for KU. The filings are based on a forecasted test year of July 1, 2017 through June 30, 2018, and a requested 10.23 percent ROE. If approved by the KPSC, new rates will be effective July 1, 2017.

• LKE received approval from the KPSC for its Solar Share community solar program. The site, near Simpsonville, Kentucky, is expandable to 4 MW, however, will be built in 500 KW sections based on customer interest.

• LKE deployed nearly 300 support personnel to three states to assist with recovery efforts during the aftermath of Hurricane Matthew.

• The Trimble County Landfill Project received Kentucky Division of Water's 401 Water Quality Certification, the first of three key environmental regulatory approvals needed to begin construction of the landfill. Two permits are still being processed by the KY Division of Waste Management and the Corps of Engineers.

• Yum! Brands became the first company in Louisville to partner with LG&E and KU in the deployment of electric vehicle ("EV") charging stations. In efforts to support employees and their lifestyles, Yum has provided an initial deployment of only one installation and are making it available to their employees/customers free of charge. LKE's new EV charging station program is being offered for commercial customers interested in hosting stations at their locations. LG&E and KU plan to install about 20 public charging stations across their service territories.

• Louisville Metro filed an amended complaint with the KPSC regarding the means by which LG&E would collect from customers the proposed gas franchise fee the city would charge LG&E. The KPSC had previously ruled that the city failed to establish a prima facie case in its original complaint. Regardless, the KPSC will ultimately rule on the substance of the matter either through this complaint proceeding or through LG&E's request for a declaratory order to which Louisville Metro has also filed a motion to dismiss.

Significant Future Events

• LG&E and KU will file a request for base rate increases on November 23, 2016.

(1) Full year forecast amount shown represents target.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues are believed to be minimal risk.
(4) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (Month) - LKE Consolidated — October 2016

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 213	$ 227	$ (14)	Due to lower FAC revenues based on the lower fuel costs shown below along with lower residential and industrial revenues, including the loss of [redacted]) as a customer.
Gas Revenues	16	18	(2)	
Total Revenues	229	245	(16)	
Cost of Sales:				
Fuel Electric Costs	58	66	8	Primarily due to lower commodity costs.
Gas Supply Expenses	5	7	2	
Purchased Power	4	5	0	
Other Electric Cost	14	15	1	
Total Cost of Sales	82	92	11	
Gross Margin:				
Electric Margin	136	142	(5)	Lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $4 million.
Gas Margin	11	11	(1)	
Total Gross Margin	147	153	(6)	
Operating Expenses:				
O&M	57	65	8	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance and outage expenses and outside services.
Depreciation & Amortization	29	30	1	
Taxes, Other than Income	5	5	(0)	
Total Operating Expenses	91	100	9	
Other income (expense)	(0)	(0)	(0)	
EBIT	56	52	4	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	38	34	4	
Income Tax Expense	15	13	(2)	
Net Income (loss) from ongoing operations	**24**	**21**	**$ 2**	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 24	$ 21	$ 2	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 21	$ 19	$ 2	
Earnings Per Share - Ongoing	$ 0.03	$ 0.03	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

October 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,393	$ 2,527	$ (134)	Due to lower volumes driven by unfavorable weather, FAC revenue from lower fuel costs (see below), and industrial volumes.
Gas Revenues	221	251	(30)	See Gas Supply Expenses explanation below.
Total Revenues	2,614	2,778	(164)	
Cost of Sales:				
Fuel Electric Costs	668	757	90	Primarily due to lower commodity costs and decreased generation as a result of mild weather.
Gas Supply Expenses	88	114	26	Due to lower gas usage (mild weather) and prices as well as lower net purchases.
Purchased Power	46	49	2	
Other Electric Cost	132	151	19	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	935	1,070	136	
Gross Margin:				
Electric Margin	1,547	1,571	(24)	Lower margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $24 million and $4 million lower retail rate mechanism revenue. This was partially offset by $5 million lower production costs and other margin components.
Gas Margin	133	137	(4)	
Total Gross Margin	1,680	1,708	(28)	
Operating Expenses:				
O&M	579	614	35	Lower O&M primarily due to lower labor and burden costs along with savings in plant maintenance, storm restoration, vegetation management, uncollectible accounts and outside services.
Depreciation & Amortization	290	298	8	Lower depreciation primarily due to project completion and spending updates as well as higher level of retirements this year.
Taxes, Other than Income	47	47	(0)	
Total Operating Expenses	916	959	43	
Other income (expense)	(9)	(6)	(4)	
EBIT	755	743	11	
Interest Expense	177	181	4	
Income from Ongoing Operations before income taxes	577	562	15	
Income Tax Expense	217	215	(2)	
Net Income (loss) from ongoing operations	**360**	**348**	**$ 13**	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 361	$ 348	$ 13	
KY Regulated Financing Costs	(25)	$ (25)	(0)	
KY Regulated Net Income	$ 336	$ 323	$ 13	
Earnings Per Share - Ongoing	$ 0.49	$ 0.47	$ 0.02	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

October 2016

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 961	$ 997	$ (36)	Due to lower volumes driven by unfavorable weather, lower FAC revenue from lower fuel costs (see below), and lower industrial volumes.
Gas Revenues	221	251	(30)	See Gas Supply Expenses explanation below.
Total Revenues	1,182	1,248	(66)	
Cost of Sales:				
Fuel Electric Costs	257	281	25	Primarily due to lower commodity costs and decreased generation as a result of mild weather.
Gas Supply Expenses	88	114	26	Due to lower gas usage (mild weather) and prices
Purchased Power	45	51	6	Lower purchased power due to lower commodity prices.
Other Electric Cost	51	61	10	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	442	507	66	
Gross Margin:				
Electric Margin	608	603	5	
Gas Margin	133	137	(4)	
Total Gross Margin	741	741	0	
Operating Expenses:				
O&M	258	277	19	Lower O&M primarily due to timing of plant maintenance and outages, vegetation management, storm restoration and labor and burden savings.
Depreciation & Amortization	117	121	4	
Taxes, Other than Income	24	23	(0)	
Total Operating Expenses	399	421	22	
Other income (expense)	(5)	(2)	(3)	
EBIT	337	317	19	
Interest Expense	58	59	1	
Income from Ongoing Operations before income taxes	278	258	20	
Income Tax Expense	106	99	(8)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**172**	**159**	**$ 13**	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - KU

October 2016

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,464	$ 1,580	$ (116)	Due to lower volumes driven by unfavorable weather and by the loss of [redacted]) as a customer.
Gas Revenues	-	-	-	
Total Revenues	1,464	1,580	(116)	
Cost of Sales:				
Fuel Electric Costs	413	480	67	Primarily due to lower commodity costs and decreased generation as a result of mild weather.
Gas Supply Expenses	-	-	-	
Purchased Power	31	43	12	Lower purchased power due to lower commodity prices.
Other Electric Cost	81	90	9	Due to lower coal generation and lower ECR consumables expense and scrubber reactant expense.
Total Cost of Sales	525	613	88	
Gross Margin:				
Electric Margin	939	967	(28)	Primarily related to lower Electric Revenues. See explanation above.
Gas Margin	-	-	-	
Total Gross Margin	939	967	(28)	
Operating Expenses:				
O&M	300	319	18	Lower O&M primarily due to timing of plant maintenance, lower storm restoration, vegetation management and outside services along with labor and burden savings.
Depreciation & Amortization	172	177	4	
Taxes, Other than Income	24	24	0	
Total Operating Expenses	496	519	23	
Other income (expense)	(4)	(3)	(0)	
EBIT	439	445	(6)	
Interest Expense	80	81	2	
Income from Ongoing Operations before income taxes	359	364	(4)	
Income Tax Expense	137	139	1	
Net Income (loss) from ongoing operations	**222**	**225**	**$ (3)**	

Note: Schedules may not sum due to rounding.

Electric Gross Margin Analysis - MTD
($ Millions) — **October 2016**

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	64	67	(3)
Demand	44	45	(1)
Base Service Charge	14	14	(0)
Rate Mechanisms	17	17	(0)
Other Rev/Cost of Sales	(0)	(0)	(0)
Other Margin Items	(2)	(2)	(0)
	136	142	(5)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	28	28	0
Demand	15	14	0
Base Service Charge	6	6	(0)
Rate Mechanisms	9	9	0
Other Rev/Cost of Sales	0	0	(0)
Other Margin Items	(2)	(2)	0
	55	55	0

KU Electric Margin

	Actual	Budget	Variance
Base Energy	36	40	(3)
Demand	30	31	(1)
Base Service Charge	8	8	0
Rate Mechanisms	8	8	(0)
Other Rev/Cost of Sales	(0)	(0)	(0)
Other Margin Items	(0)	(0)	(0)
	81	87	(6)

LKE Base Energy Price/Vol Variance

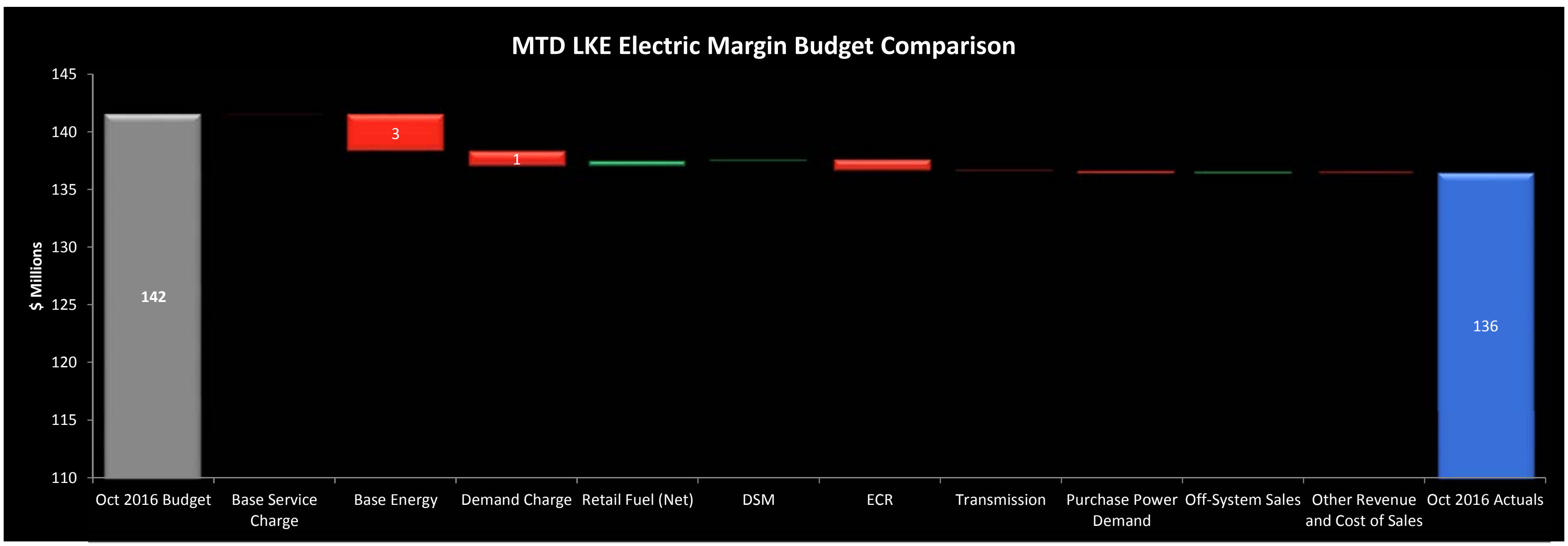
	Volume	Price	Total Variance
Residential	(3)	0	(3)
Commercial	0	(1)	(0)
Industrial	(0)	0	(0)
Public Authority	0	(0)	0
Street Lights	(0)	0	0
Municipals	(0)	(0)	(0)
Other	0	0	0
	(3)	(0)	(3)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(1)	0	(0)
Commercial	1	(1)	0
Industrial	(0)	0	0
Public Authority	0	(0)	0
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	0	(0)	0

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(3)	0	(2)
Commercial	(0)	(0)	(0)
Industrial	(0)	0	(0)
Public Authority	0	(0)	0
Street Lights	(0)	0	0
Municipals	(0)	(0)	(0)
Other	0	0	0
	(3)	0	(3)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Electric Gross Margin Analysis - YTD
($ Millions)

October 2016

LKE Electric Margin

	Actual	Budget	Variance
Base Energy	810	823	(13)
Demand	460	471	(11)
Base Service Charge	137	137	(0)
Rate Mechanisms	158	163	(4)
Other Rev/Cost of Sales	(3)	(6)	3
Other Margin Items	(15)	(17)	2
	1547	1571	(24)

LG&E Electric Margin

	Actual	Budget	Variance
Base Energy	335	333	1
Demand	152	151	1
Base Service Charge	56	56	(1)
Rate Mechanisms	82	83	(1)
Other Rev/Cost of Sales	(0)	(2)	1
Other Margin Items	(16)	(18)	2
	608	603	5

KU Electric Margin

	Actual	Budget	Variance
Base Energy	475	489	(14)
Demand	308	320	(12)
Base Service Charge	81	81	0
Rate Mechanisms	76	80	(4)
Other Rev/Cost of Sales	(3)	(4)	1
Other Margin Items	1	1	(0)
	939	967	(28)

LKE Base Energy Price/Vol Variance

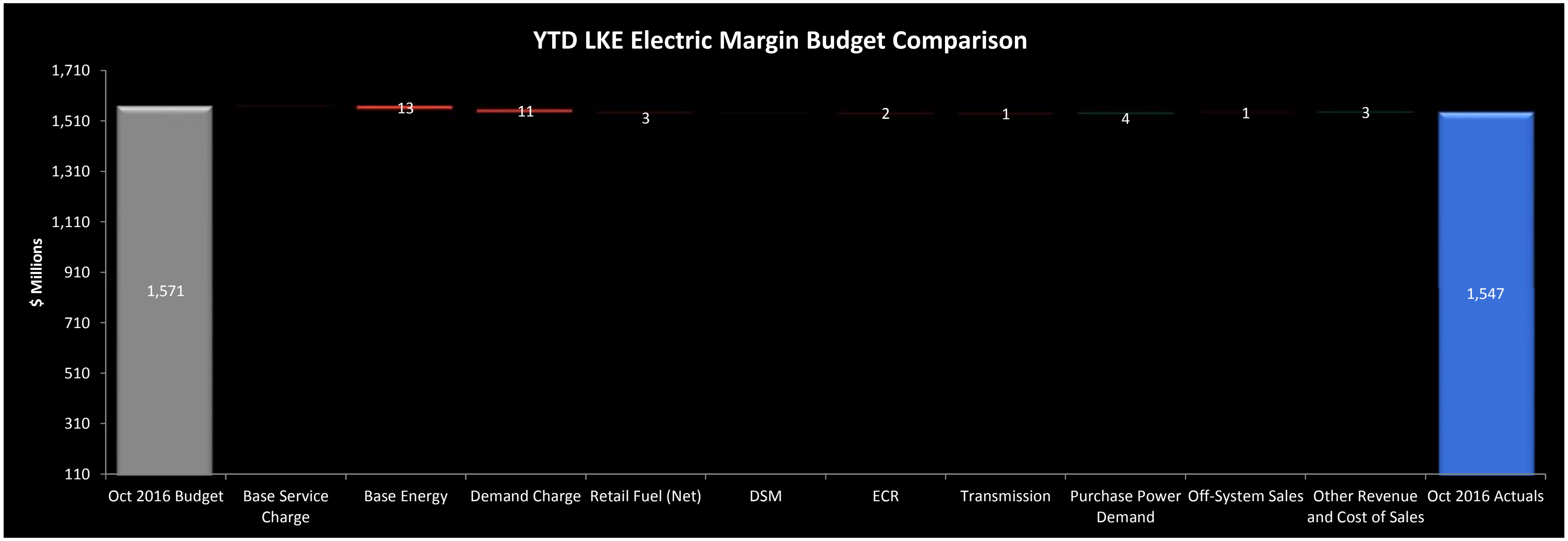
	Volume	Price	Total Variance
Residential	(12)	5	(7)
Commercial	6	(8)	(2)
Industrial	(5)	2	(3)
Public Authority	1	(1)	1
Street Lights	(1)	1	0
Municipals	(0)	(2)	(2)
Other	0	0	0
	(10)	(2)	(13)

LG&E Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(3)	2	(1)
Commercial	6	(5)	2
Industrial	(3)	1	(1)
Public Authority	1	0	1
Street Lights	0	(0)	0
Municipals	0	0	0
Other	0	0	0
	3	(1)	1

KU Base Energy Price/Vol Variance

	Volume	Price	Total Variance
Residential	(10)	3	(7)
Commercial	0	(3)	(3)
Industrial	(2)	1	(1)
Public Authority	0	(1)	(1)
Street Lights	(2)	1	(0)
Municipals	(0)	(2)	(2)
Other	0	0	0
	(13)	(1)	(14)



Note: For additional detailed information, please refer to the monthly Margin results files per Revenue Accounting & Analysis Department.

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Gas Gross Margin — October 2016

($ Millions)

	MTD Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD Margin Variance
Gas Base Service Charge	$ 5	$ 5		(0)	$ 52	$ 52		$ (0)
Gas Supply Costs								
Gas Supply Costs	(4)	(6)	$ 2		$ (79)	$ (103)	$ 24	
GSC Revenue	4	6	$ (2)		$ 80	$ 103	$ (24)	
Net Gas Supply Costs				(0)				$ 1
Retail Gas (a)	3	5		(2)	$ 62	$ 71		$ (9)
Wholesale Gas (a)	-	-		-	$ (0)	$ -		$ (0)
DSM	0	0		(0)	$ 0	$ 1		$ (1)
GLT	1	1		0	$ 13	$ 12		$ 1
WNA	1	-		1	$ 4	$ -		$ 4
Other Margin	0	0		(0)	$ 1	$ 1		$ (0)
Gas Margin Variance				$ (1)				$ (4)

(a) Retail and wholesale gas sales - excludes GSC

MTD	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 2	527,264	$ 2.87	$ 3	894,626	$ 2.87	($1.1)	($1.1)	$0.0
Commercial	1	300,850	2.01	1	404,363	2.10	($0.2)	($0.2)	($0.0)
Industrial	0	84,380	1.82	0	133,004	2.07	($0.1)	($0.1)	($0.0)
Public Authority	0	40,089	1.71	0	72,044	1.91	($0.1)	($0.1)	($0.0)
Transportation	1	1,004,313	0.52	1	1,175,297	0.54	($0.1)	($0.1)	($0.0)
Interdepartmental	0	21,406	14.30	0	203,053	1.51	($0.0)	($0.3)	$0.3
Ultimate Consumer	$ 3	1,978,302	$ 1.60	$ 5	2,882,387	$ 1.65	($1.6)	($1.8)	$0.2

YTD	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 37	12,870,022	$ 2.87	$ 44	15,257,647	$ 2.87	($7)	$ (7)	$ (0)
Commercial	13	6,227,616	2.09	14	6,789,177	2.13	($1)	$ (1)	$ (0)
Industrial	2	914,979	1.95	2	1,165,629	2.11	($1)	$ (1)	$ (0)
Public Authority	2	846,700	2.03	2	1,088,315	2.06	($1)	$ (0)	$ (0)
Transportation	6	11,244,980	0.51	5	9,955,727	0.50	$1	$1	$0
Interdepartmental	3	288,711	10.69	3	1,199,542	2.53	$0	($2)	$2
Ultimate Consumer	$ 62	32,393,008	$ 1.92	$ 71	35,456,037	$ 2.00	($9)	($11)	$2

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	19	21	2	(0)	(0)	0	2	(0)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	3	0	0	0	0	0	0
Energy Supply and Analysis	1	1	0	0	(0)	0	(0)	0
Generation Services	1	2	1	(0)	(0)	1	(0)	0
Electric Distribution	5	6	1	0	1	(0)	(0)	0
Gas Distribution	3	3	0	0	0	0	(0)	0
Safety and Technical Training	1	0	(0)	(0)	(0)	(0)	(0)	0
Customer Services	7	7	1	(0)	0	0	0	1
Chief Operations Officer	**38**	**43**	**5**	**0**	**1**	**1**	**2**	**0**
General Counsel	2	2	0	(0)	0	0	0	0
Human Resources	1	1	0	0	(0)	0	0	0
General Counsel & HR	**2**	**3**	**0**	**0**	**0**	**0**	**0**	**0**
Audit Services	0	0	0	0	-	(0)	0	0
Controller	1	1	(0)	(0)	-	0	0	0
Information Technology	4	5	1	0	(0)	0	0	0
Supply Chain	0	0	(0)	(0)	-	(0)	(0)	(0)
Treasurer	1	1	0	(0)	-	(0)	0	0
State Regulation and Rates	0	0	0	(0)	-	0	0	0
Chief Financial Officer	**7**	**7**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**10**	**12**	**2**	**1**	**(0)**	**0**	**(0)**	**1**
O&M Total MTD	**57**	**65**	**8**	**2**	**1**	**1**	**2**	**2**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	162	171	10	3	(2)	3	10	(4)
Project Engineering	0	1	0	0	-	(0)	(0)	0
Transmission	24	26	2	0	0	0	0	1
Energy Supply and Analysis	7	7	0	0	(0)	0	0	0
Generation Services	12	13	1	0	(0)	1	(0)	1
Electric Distribution	58	62	4	(1)	5	(1)	0	1
Gas Distribution	27	28	1	1	(1)	1	0	0
Safety and Technical Training	4	4	0	(0)	(0)	(0)	0	0
Customer Services	68	73	4	1	0	1	0	2
Chief Operations Officer	**362**	**385**	**23**	**5**	**2**	**4**	**10**	**1**
General Counsel	24	27	2	0	0	1	0	1
Human Resources	5	6	1	0	(0)	0	0	0
General Counsel & HR	**30**	**33**	**3**	**0**	**0**	**1**	**0**	**1**
Audit Services	1	1	0	0	-	(0)	0	0
Controller	8	8	0	(0)	-	0	0	0
Information Technology	46	50	5	3	(0)	1	0	1
Supply Chain	3	3	(0)	(0)	(0)	(0)	0	0
Treasurer	9	9	0	(0)	-	(0)	(0)	1
State Regulation and Rates	3	3	(0)	0	-	0	(0)	0
Chief Financial Officer	**70**	**75**	**5**	**2**	**(0)**	**1**	**0**	**2**
Corporate	**116**	**121**	**5**	**3**	**(2)**	**3**	**(1)**	**2**
O&M Total YTD	**579**	**614**	**35**	**11**	**(0)**	**9**	**10**	**6**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	200	206	6	3	(3)	3	5	(1)
Project Engineering	0	1	0	0	-	(0)	(0)	0
Transmission	30	30	1	0	(0)	(0)	0	1
Energy Supply and Analysis	9	9	0	0	(0)	(0)	0	0
Generation Services	15	15	0	(0)	(0)	0	(0)	1
Electric Distribution	69	73	4	(2)	3	(0)	0	2
Gas Distribution	34	34	(0)	0	(1)	0	(0)	0
Safety and Technical Training	5	5	0	(0)	(0)	0	0	(0)
Customer Services	84	87	3	1	(0)	1	0	2
Chief Operations Officer	**446**	**459**	**13**	**2**	**(1)**	**3**	**5**	**4**
General Counsel	31	32	1	(0)	0	0	0	1
Human Resources	7	7	0	0	(0)	0	0	0
General Counsel & HR	**38**	**39**	**1**	**0**	**0**	**0**	**0**	**1**
Audit Services	2	2	0	0	-	(0)	0	0
Controller	10	10	0	(0)	-	0	0	0
Information Technology	57	60	3	3	(0)	0	0	0
Supply Chain	4	4	(0)	(0)	(0)	0	0	(0)
Treasurer	11	11	0	(0)	-	(0)	(0)	1
State Regulation and Rates	4	3	(0)	(0)	-	0	(0)	0
Chief Financial Officer	**87**	**90**	**3**	**2**	**(0)**	**0**	**0**	**1**
Corporate	**138**	**144**	**6**	**0**	**(1)**	**4**	**(0)**	**3**
O&M Total Full Year	**708**	**731**	**23**	**5**	**(3)**	**8**	**5**	**9**

Note: Schedules may not sum due to rounding.

Financing Activities — October 2016

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 923.9	$ 923.8	$ (0.0)	$ 923.8	$ 923.8	$ (0.0)
End Bal	923.8	923.8	(0.0)	898.9	923.8	24.9
Ave Bal	**$ 923.8**	**$ 923.8**	**$ (0.0)**	**$ 911.3**	**$ 923.8**	**$ 12.5**
Interest Exp	**$ 10.7**	**$ 11.6**	**$ 0.8**	**$ 12.7**	**$ 13.9**	**$ 1.2**
Rate	**1.37%**	**1.48%**	**0.11%**	**1.37%**	**1.48%**	**0.10%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ -	$ 4,210.0	$ 4,210.0	$ -
End Bal	4,210.0	4,210.0	-	4,210.0	4,210.0	-
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ -**	**$ 4,210.0**	**$ 4,210.0**	**$ -**
Interest Exp	**$ 147.7**	**$ 147.7**	**$ (0.0)**	**$ 175.3**	**$ 175.3**	**$ -**
Rate	**4.14%**	**4.14%**	**0.00%**	**4.10%**	**4.10%**	**0.00%**
Short-term Debt						
Beg Bal	$ 318.9	$ 295.5	$ (23.4)	$ 451.8	$ 347.7	$ (104.1)
End Bal	240.8	297.0	56.3	509.7	347.7	(162.0)
Ave Bal	**$ 279.8**	**$ 296.3**	**$ 16.4**	**$ 480.8**	**$ 347.7**	**$ (133.1)**
Interest Exp	**$ 3.2**	**$ 3.9**	**$ 0.7**	**$ 5.0**	**$ 4.8**	**$ (0.2)**
Rate	**1.34%**	**1.55%**	**0.21%**	**1.02%**	**1.35%**	**0.33%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (46.3)	$ (41.8)	$ 4.6	$ (42.2)	$ (39.6)	$ 2.6
End Bal	(44.7)	(41.1)	3.6	(43.2)	(39.6)	3.6
Ave Bal	**$ (45.5)**	**$ (41.4)**	**$ 4.1**	**$ (42.7)**	**$ (39.6)**	**$ 3.1**
Total End Bal	**$ 5,329.9**	**$ 5,389.8**	**$ 59.9**	**$ 5,575.3**	**$ 5,441.9**	**$ (133.5)**
Total Average Bal	**$ 5,368.2**	**$ 5,388.7**	**$ 20.5**	**$ 5,559.4**	**$ 5,441.9**	**$ (117.5)**
Total Expense Excl I/C [1]	**$ 177.1**	**$ 180.9**	**$ 3.8**	**$ 212.7**	**$ 217.2**	**$ 4.5**
Rate	**3.86%**	**3.93%**	**0.07%**	**3.73%**	**3.90%**	**0.16%**

[1] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[2]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 153		$ 147
LG&E	500	88		412
KU	598	-	$ 198	400
TOTAL	$ 1,398	$ 241	$ 198	$ 959

[2] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics(1) Moody's	LKE 2016 Actual YTD	LKE 2016 Budget YTD	LG&E 2016 Actual YTD	LG&E 2016 Budget YTD	KU 2016 Actual YTD	KU 2016 Budget YTD
CFO pre-WC / Debt	19%	19%	28%	27%	26%	26%
CFO pre-WC + Interest / Interest	5.8	5.7	8.2	8.1	7.4	7.4
CFO pre-WC - Dividends / Debt	16%	22%	28%	27%	17%	36%
Debt to Capitalization(2)	47%	47%	38%	39%	38%	38%

Credit Metrics Moody's	LKE 2016 BP 2017	LKE 2016 BP 2018	LG&E 2016 BP 2017	LG&E 2016 BP 2018	KU 2016 BP 2017	KU 2016 BP 2018
CFO pre-WC / Debt	19%	20%	28%	29%	28%	26%
CFO pre-WC + Interest / Interest	5.8	5.7	7.9	7.8	7.7	7.2
CFO pre-WC - Dividends / Debt	27%	27%	35%	38%	36%	32%
Debt to Capitalization(2)	45%	45%	38%	37%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2015	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — October 2016

($ Millions)

	10/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 16	$ 14	$ 1	
Accounts Receivable (Trade)	339	350	(11)	
Inventory	298	290	8	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	21	66	(45)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	40	42	(3)	
Total Current Assets	713	763	(50)	
Property, Plant, and Equipment	11,499	11,819	(320)	
Intangible Assets	101	87	14	Amortization related to software classified as intangibles in budget versus PP&E in actuals.
Other Property and Investments	1	1	(0)	
Regulatory Assets Non Current	771	748	23	
Goodwill	997	997	-	
Other Long-term Assets	79	83	(5)	
Total Assets	**$ 14,161**	**$ 14,499**	**$ (339)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 225	$ 278	$ (52)	Primarily due to decrease in accruals partially offset by an increase in natural gas purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	55	52	3	
Derivative Liability	6	5	1	
Accrued Taxes	48	98	(50)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. In Q3, NOL addition and utilization were actualized causing accrued taxes to decrease by $16 mil ($-13 mil LGE, $-10 mil KU, +$7 mil LKE Other).
Regulatory Liabilities Current	23	29	(6)	
Other Current Liabilities	231	235	(3)	
Total Current Liabilities	588	696	(109)	
Debt - Affiliated Company	553	404	149	Increase in affiliate debt due to payoff of $75m credit facility and other funding needs. Budget assumed pay down of affiliate debt balance in March 2016 and quarterly pay off of any cash needed for operations on non quarter months. The forecast does not assume any pay off of the short term debt with affiliate. Prior years federal and state tax settlement generated $10.5 mil in cash at LKE Other.
Debt [(1)]	4,777	4,986	(208)	
Total Debt	5,330	5,390	(60)	
Deferred Tax Liabilities	1,673	1,641	32	
Investment Tax Credit	132	125	7	
Accum Provision for Pension & Related Benefits	245	269	(24)	
Asset Retirement Obligation	366	504	(138)	Primarily due to ARO revaluation to reflect updates in the estimated cash flows for ash and environmental ponds as a result of further engineering refinements to the design.
Regulatory Liabilities Non Current	906	859	47	
Derivative Liability	44	42	2	
Other Liabilities	181	194	(13)	
Total Deferred Credits and Other Liabilities	3,548	3,634	(86)	
Equity	4,695	4,779	(84)	
Total Liabilities and Equity	**$ 14,161**	**$ 14,499**	**$ (339)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

October 2016

($ Millions)

	10/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 5	$ 5	$ 0	
Accounts Receivable (Trade)	143	149	(5)	
Inventory	153	143	10	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	9	25	(16)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates.
Prepayments and other current assets	42	33	9	
Total Current Assets	353	354	(1)	
Property, Plant, and Equipment	4,935	5,081	(146)	
Intangible Assets	6	(1)	7	
Other Property and Investments	1	1	-	
Regulatory Assets Non Current	431	417	14	
Goodwill	-	-	-	
Other Long-term Assets	20	19	1	
Total Assets	**$ 5,745**	**$ 5,871**	**$ (126)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 153	$ 188	$ (35)	Primarily due to decrease in accruals partially offset by an increase in natural gas purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	26	25	1	
Derivative Liability	6	5	1	
Accrued Taxes	23	53	(29)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. Rebalancing NOL Addition in Q3 for the change in summer months income caused a $9 mil decrease in Accrued Taxes.
Regulatory Liabilities Current	6	13	(7)	
Other Current Liabilities	90	78	13	Primarily due to reclassification of ARO liability from long-term to current.
Total Current Liabilities	305	362	(57)	
Debt - Affiliated Company	38	-	38	Primarily due to increase in notes receivable from affiliate company for funds provided in money pool.
Debt [(1)]	1,730	1,819	(89)	
Total Debt	1,768	1,819	(51)	
Deferred Tax Liabilities	944	924	20	
Investment Tax Credit	37	34	3	
Accum Provision for Pension & Related Benefits	19	39	(20)	Primarily due to additional pension contribution partially offset by roll forward of funded status, both of which are not included in budgeted amounts.
Asset Retirement Obligation	106	154	(48)	Primarily due to ARO revaluation to reflect updates in the estimated cash flows for ash and environmental ponds as a result of further engineering refinements to the design and reclassification of a portion of ARO liability from long-term to current.
Regulatory Liabilities Non Current	365	343	22	
Derivative Liability	44	42	2	
Other Liabilities	86	89	(3)	
Total Deferred Credits and Other Liabilities	1,600	1,624	(24)	
Equity	2,072	2,066	6	
Total Liabilities and Equity	**$ 5,745**	**$ 5,871**	**$ (126)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU

October 2016

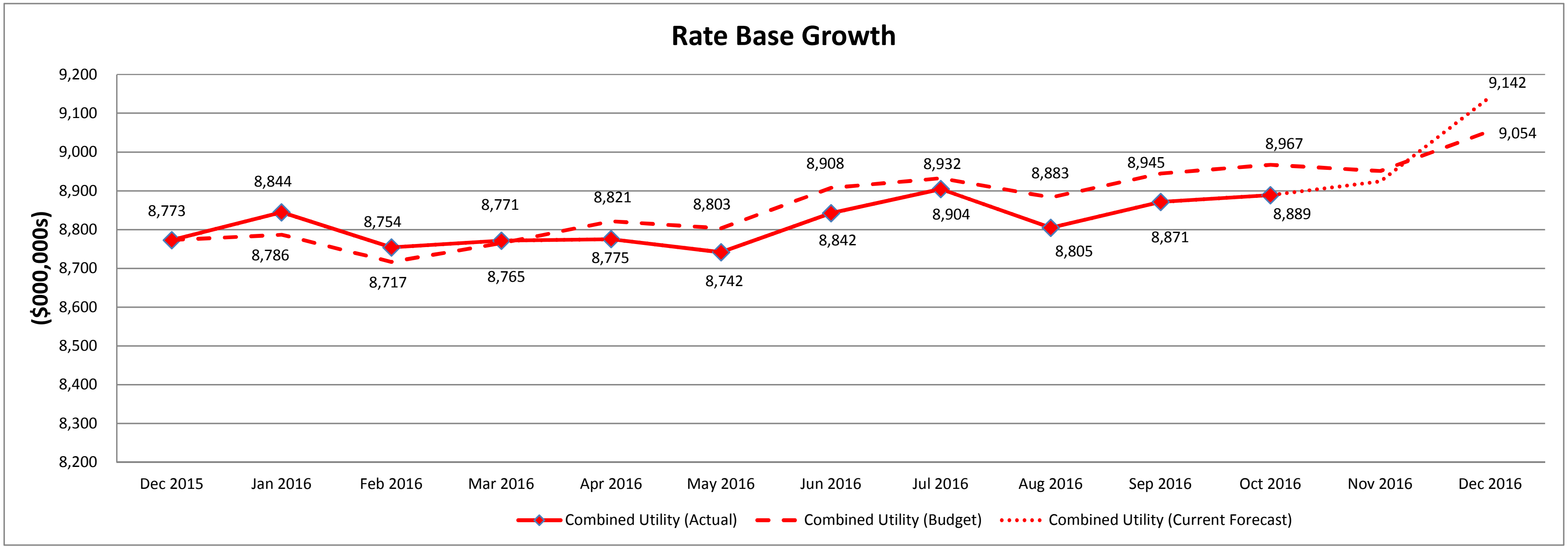
($ Millions)

	10/31/2016	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 10	$ 5	$ 5	
Accounts Receivable (Trade)	195	200	(6)	
Inventory	145	148	(3)	
Deferred Income Taxes	-	-	-	
Regulatory Assets Current	12	41	(29)	Primarily due to a decrease in the balance related to ECR as a result of an ECR roll-in to base rates and decrease in the FAC balance due to lower costs of native fuel expense.
Prepayments and other current assets	58	21	37	Primarily due to increase in notes receivable from affiliate company for funds provided in money pool.
Total Current Assets	419	415	4	
Property, Plant, and Equipment	6,556	6,730	(174)	
Intangible Assets	13	7	6	
Other Property and Investments	0	0	-	
Regulatory Assets Non Current	337	327	9	
Goodwill	-	-	-	
Other Long-term Assets	56	55	1	
Total Assets	**$ 7,382**	**$ 7,535**	**$ (153)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 113	$ 128	$ (15)	Due to decrease in accruals and lower coal purchases.
Dividends Payable to Affiliated Companies	-	-	-	
Customer Deposits	28	26	2	
Derivative Liability	-	-	-	
Accrued Taxes	22	46	(24)	Due to difference in assumption related to expected income tax extension settlement and budget did not reflect delayed timing of property tax payments that occurred in Q1. IN Q3, KU had more NOL utilization than budget causing Accrued taxes to decrease by $7 mil.
Regulatory Liabilities Current	17	16	0	
Other Current Liabilities	91	100	(9)	
Total Current Liabilities	271	317	(45)	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	2,324	2,365	(41)	
Total Debt	2,324	2,365	(41)	
Deferred Tax Liabilities	1,166	1,168	(2)	
Investment Tax Credit	95	91	4	
Accum Provision for Pension & Related Benefits	35	38	(3)	
Asset Retirement Obligation	260	350	(90)	Primarily due to ARO revaluation to reflect updates in the estimated cash flows for ash and environmental ponds as a result of further engineering refinements to the design.
Regulatory Liabilities Non Current	459	434	25	
Derivative Liability	-	-	-	
Other Liabilities	47	55	(8)	
Total Deferred Credits and Other Liabilities	2,062	2,136	(74)	
Equity	2,724	2,717	7	
Total Liabilities and Equity	**$ 7,382**	**$ 7,535**	**$ (153)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake



Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

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