Kentucky Utilities Company
Case No. 2016-00370
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, 14, and 23.

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

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

Section 14(4)
KU 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: 182365
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,

KENTUCKY UTILITIES COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is August 17, 1912 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 28th day of October, 2016, in the 225th year of the Commonwealth.

COMMONWEALTH OF KENTUCKY
OFFICE OF SECRETARY OF STATE

Alison Lundergan Grimes
Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
182365/0028494

Commonwealth of Virginia

State Corporation Commission

CERTIFICATE OF GOOD STANDING

I Certify the Following from the Records of the Commission:

That KENTUCKY UTILITIES COMPANY is duly incorporated under the law of the Commonwealth of Virginia;

That the date of its incorporation is November 26, 1991;

That the period of its duration is perpetual; and

That the corporation is in existence and in good standing in the Commonwealth of Virginia as of the date set forth below.

Nothing more is hereby certified.

Signed and Sealed at Richmond on this Date:
October 28, 2016

Joel H. Peck, Clerk of the Commission

CISECOM
Document Control Number: 1610285330

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
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 KU is Kentucky Utilities Company. It has never done business in Kentucky under an assumed name and has never filed a Certificate of Assumed Name as may be required by KRS 365.015. KU does business in Virginia under the name Old Dominion Power Company. Please see the attached certificate regarding the use by KU of the name Old Dominion Power Company in Virginia. KU has never done business in Tennessee under an assumed name.

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Wise, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By [signature]
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

[signature]
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Wise on the 26 day of November, 1991, and admitted to record as the law directs.

[signature]
Clerk

This is to certify that this is a true and correct reproduction or abstract of the official record filed with the Circuit Court for the City or County of Wise County/ City of Norton, Virginia.

C. Gary Rakes, Clerk

Date Issued 11-26-91

[signature]
[redacted] or Deputy

(SEAL)

VOID IF ALTERED OR DOES NOT BEAR IMPRESSED SEAL OF COURT

VS3A - 9/03

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Scott, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By [signature]
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

NOTARY PUBLIC STATE AT LARGE, KY.

[signature]
Notary Public

COMMONWEALTH OF VIRGINIA:

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Scott on the 2nd day of December, 1991, and admitted to record as the law directs, at 8:00 A.M.

[signature]
Clerk

A TRUE COPY TESTE:
CIRCUIT COURT CLERK'S OFFICE
SCOTT COUNTY, VIRGINIA
[signature] CLERK

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Dickenson, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Dickenson on the 26th day of November, 1991, and admitted to record as the law directs.

Lula Large, Deputy
Clerk

A COPY TESTE:

Lula Large DEPUTY CLERK

Book 2 page 363

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Lee, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By [signature]
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of Janunry, 1993.

NOTARY PUBLIC STATE AT LARGE

[signature]
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Lee on the 26th day of November, 1991, and admitted to record as the law directs.
1:28 pm

Charles Calton, Clerk
Clerk
By: Karen C. Jones DC.

A COPY TESTE:
CHARLES CALTON, CLERK
Karen C. Jones
Deputy Clerk

CERTIFICATE OF FICTITIOUS NAME

This is to certify that Kentucky Utilities Company, a Virginia public service corporation, is the owner of the business to be conducted or transacted in the County of Russell, Virginia, trading under the name of:

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

I, George S. Brooks II, a Notary Public in and for the aforesaid state, do hereby certify that John T. Newton, whose name is signed to the above certificate this day appeared before me and acknowledged the same.

Given under my hand this 22nd day of November, 1991.

My Commission expires on the 19th day of January, 1993.

George S. Brooks II
Notary Public

The foregoing Certificate of Assumed Name was presented in the Office of the Clerk of the Circuit Court of the County of Russell on the 26th day of November, 1991, and admitted to record as the law directs.

Perry Blevins
Clerk

A COPY TESTE
Joseph H. Gilmer, Clerk
Perry Blevins

Commonwealth of Virginia

State Corporation Commission

I Certify the Following from the Records of the Commission:

The foregoing is a true copy of an assumed or fictitious name certificate on file in the Clerk's Office of the Commission certifying that KENTUCKY UTILITIES COMPANY conducts business under the assumed or fictitious name of Old Dominion Power Company.

Nothing more is hereby certified.

STATE CORPORATION COMMISSION VIRGINIA SIC SEMPER TYRANNIS 1903

Signed and Sealed at Richmond on this Date:
November 1, 2016

Joel H. Peck

Joel H. Peck, Clerk of the Commission

CIS0505

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company

One Quality Street
Lexington, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In seventy-seven counties in the Commonwealth of Kentucky
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
Lexington, 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
Lexington, 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
Lexington, 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. Three phase service under this rate schedule is restricted to those customers being billed on this rate schedule as of July 1, 2004. **T**

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.05015	$0.03508	$0.08523	**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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 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:	$0.05266	**T/R**
On-Peak Hours:	$0.27646	**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
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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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.

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. 2016-00370 dated xxxx

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:	$ 0.03508	**T/R**
Plus a Demand Charge per kW:		**T**
Base Hours:	$ 3.44	**T/R**
Peak Hours:	$ 7.87	**T/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

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.
2016-00370 dated xxxx

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.

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. **T**

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.05015	$0.03508	$0.08523	**R**

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

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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. 13, 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**
	$0.07137	$0.03548	$0.10685	**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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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.

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. 2016-00370 dated xxxx

Standard Rate **AES**
ALL ELECTRIC SCHOOL

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate is available for secondary and primary service to:
(1) a complex of school buildings on a central campus; **T**
(2) an individual school building; or **T**
(3) an addition to an existing school building.

School buildings, as referred to herein, shall be defined as buildings used as classrooms, laboratories, gymnasiums, libraries, cafeterias, school related offices or for other bona fide school purposes by duly constituted school authorities of Kentucky. Served electrically by Kentucky Utilities Company, such energy requirements include, but are not limited to, lighting, heating, cooling, and water heating. School buildings not receiving every energy requirement electrically shall be separately metered from the above defined service and served under the applicable rate. Other fuels may be used as incidental to and for instructional laboratory and other miscellaneous purposes without affecting the availability of this rate.

At those locations where the school owns its distribution system and makes the service connections to the various buildings and/or load centers, Company shall be given the option of providing service by use of the existing Customer-owned distribution system, or of constructing its own facilities in accordance with the Company's Overhead Construction Standards. In any event, Company's investment in the facilities it provides may be limited to an amount not exceeding twice the estimated annual revenue from Customer’s service. Should Company’s investment in the facilities required to provide service to Customer exceed twice the revenue anticipated from the service to Customer and at Customer’s option, Customer may make a contribution for the difference in the investment required in facilities necessary to provide service and twice the anticipated revenue, so as to receive service under this schedule.

This Rate Schedule is not available to privately operated kindergartens or daycare centers and is restricted to those customers who were qualified for and being served on Rate AES as of July 1, 2011. Because this rate schedule is closed to new customers, 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.

RATE

Basic Service Charge per meter per month:		$ 85.00 single-phase service		**T/I**
		$140.00 three-phase service		**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.04996	$0.03523	$0.08519	**R**

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. 2016-00370 dated xxxx

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.

Standard Rate **PS**
POWER SERVICE

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 PSC 13, Fourth Revision of Original Sheet No. 20, Large Power Service, or Fourth Revision of Original Sheet No. 30, Mine Power Service, 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:	$ 0.03572	$ 0.03472	**T/I**
Plus a Demand Charge per kW:			**T**
Summer Rate:			
(Five Billing Periods of May through September)	$20.71	$ 20.78	**I**
Winter Rate:			
(All other months)	$18.43	$ 18.54	**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 expected load 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Standard Rate **PS**
POWER SERVICE

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 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).

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

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

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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. 2014-00371 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	
Plus an Energy Charge per kWh:	$ 0.03531	**T/I**
Plus a Maximum Load Charge per kW:		**T**
Peak Demand Period:	$ 7.81	**T/I**
Intermediate Demand Period:	$ 6.11	**T/I**
Base Demand Period:	$ 3.24	**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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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, at 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 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:	$ 0.03433	**T/I**
Plus a Maximum Load Charge per kVA:		**T**
Peak Demand Period:	$ 6.83	**T/I**
Intermediate Demand Period:	$ 5.34	**T/I**
Base Demand Period:	$ 2.92	**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 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 **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

Standard Rate **TODP**
TIME-OF-DAY PRIMARY SERVICE

DETERMINATION OF MAXIMUM LOAD T

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.

T

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 ninety (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, 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. 2016-00370 dated xxxx

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:	$	0.03363	**T/I**
Plus a Maximum Load Charge per kVA:			**T**
Peak Demand Period:	$	6.72	**T/I**
Intermediate Demand Period:	$	5.26	**T/I**
Base Demand Period:	$	2.12	**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 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

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

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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 ninety (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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00221 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 Rate FLS schedule of Louisville Gas and Electric 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	$1,500.00	**R/I**
Plus an Energy Charge per kWh:	$ 0.03433	$ 0.03344	**T/R**
Plus a Maximum Load Charge per kVA:			**T**
Peak Demand Period:	$ 6.27	$ 3.51	**T/I**
Intermediate Demand Period:	$ 4.76	$ 2.47	**T/I**
Base Demand Period:	$ 2.60	$ 1.65	**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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

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

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

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 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 years with successive one 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 KU and LG&E. 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.

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	Monthly Charge Ornamental	
High Pressure Sodium						
462/472	Cobra Head	5,800	0.083	$ 9.86	$15.65	I
463/473	Cobra Head	9,500	0.117	10.79	16.44	I
464/474	Cobra Head	22,000*	0.242	16.08	23.40	I
465/475	Cobra Head	50,000*	0.471	25.61	32.84	I
487	Directional	9,500	0.117	$10.44		I
488	Directional	22,000*	0.242	15.42		
489	Directional	50,000*	0.471	21.95		
428	Open Bottom	9,500	0.117	$ 8.87		
Metal Halide						D
451	Directional	32,000*	0.350	$22.80		T
						D
Light Emitting Diode (LED)						N
390	Cobra Head	8,179	0.080	$15.21		N
391	Cobra Head	14,166*	0.134	18.42		N
392	Cobra Head	23,214*	0.228	28.09		N

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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. 2016-00370 dated xxxx

Kentucky Utilities Company

Standard Rate **LS**
Lighting Service

RATE (continued) **N**

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only
LED (continued)				
393	Open Bottom	5,007	0.050	$10.13

OVERHEAD SERVICE (continued)

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.

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 Fixture Only	Monthly Charge Decorative Smooth	Monthly Charge Historic Fluted
High Pressure Sodium						
467	Colonial	5,800	0.083		$14.57	
468	Colonial	9,500	0.117		14.95	
401/411	Acorn	5,800	0.083		$19.88	$28.36
420/430	Acorn	9,500	0.117		20.41	29.04
414	Victorian	5,800	0.083			$36.70
415	Victorian	9,500	0.117			37.46
492/476	Contemporary	5,800	0.083	$17.12	$22.39	
497/477	Contemporary	9,500	0.117	17.00	27.71	
498/478	Contemporary	22,000*	0.242	19.84	35.68	
499/479	Contemporary	50,000*	0.471	24.15	42.55	
300	Dark Sky	4,000	0.060		$26.46	
301	Dark Sky	9,500	0.117		28.18	

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
Metal Halide						T T T T D
491/495	Contemporary	32,000*	0.350	$24.68	$41.06	T/I D
Light Emitting Diode (LED)						N
396	Cobra Head	8,179	0.080		$36.27	
397	Cobra Head	14,166*	0.134		39.47	
398	Cobra Head	23,214*	0.228		49.15	
399	Colonial, 4-Sided	5,665	0.068		$38.32	

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

T

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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 comprising 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.

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

OVERHEAD SERVICE **T**
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). Company has, upon request, furnished poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Fixture and Pole	
High Pressure Sodium						
461/471	Cobra Head	4,000	0.060	$10.07	$14.08	I
409	Cobra Head	50,000	0.471	16.27		I
426	Open Bottom	5,800	0.083	8.54		
Metal Halide						
450/454	Directional	12,000*	0.150	$16.13	$20.89	N
455	Directional	32,000*	0.350		27.56	T
452/459	Directional	107,800*	1.080	47.70	52.45	N
Mercury Vapor						
446/456	Cobra Head	7,000	0.207	$11.09	$14.01	I
447/457	Cobra Head	10,000	0.294	13.49	15.82	I
448/458	Cobra Head	20,000	0.453	14.88	17.86	I
404	Open Bottom	7,000	0.207	11.87		

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. 2016-00370 dated xxxx

OVERHEAD SERVICE (continued)

RATE Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	
Incandescent					
421	Tear Drop	1,000	0.102	$ 3.81	
422	Tear Drop	2,500	0.201	5.11	
424	Tear Drop	4,000	0.327	7.63	D
425	Tear Drop	6,000	0.447	10.19	

Where the location of existing poles was not suitable, or where there were no existing poles for mounting of lights, and Customer requested service under these conditions, Company may have furnished the requested facilities at an additional charge determined under the Excess Facilities Rider.

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	Monthly Charge Historic Fluted	
Metal Halide							
460	Directional	12,000	0.150		$35.23		I
469	Directional	32,000	0.350		39.76		I
470	Directional	107,800*	1.080		61.66		T
490/494	Contemporary	12,000*	0.150	$17.45	$31.42		N
493/496	Contemporary	107,800*	1.080	51.32	65.28		N
High Pressure Sodium							
440/410	Acorn	4,000	0.060		$18.13	$26.77	I
466	Colonial	4,000	0.060		$12.95		I
412	Coach	5,800	0.083		$36.70		I
413	Coach	9,500	0.117		37.46		I

UNDERGROUND SERVICE (continued)

RATE

Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Monthly Charge Decorative Smooth**	
					T T
360	Granville	16,000	0.181	$62.30	

Granville units are restricted to installations for the City of London.

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.

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, and the Company shall initiate service corrections within two (2) business days after such notification by Customer.

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. 2016-00370 dated xxxx

Standard Rate **RLS**
Restricted Lighting Service

TERMS AND CONDITIONS (Continued)

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: July 1, 2015

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. 2014-00371 dated June 30, 2015

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
$0.07328 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 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:	$0.09289	**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.

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.

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. 2016-00370 dated xxxx

Standard Rate **TE**
Traffic Energy Service

CONDITIONS OF SERVICE (continued)

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.

T

Standard Rate **PSA**

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

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.

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

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.

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

Pole and Structure Attachment Charges

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

Standard Rate **PSA**
Pole and Structure Attachment Charges T

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.

Standard Rate **PSA**
Pole and Structure Attachment Charges

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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.

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. 2016-00370 dated xxxx

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.

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, 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.

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. 2016-00370 dated xxxx

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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.

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. 2016-00370 dated xxxx

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.

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), AES, 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:	$185.28	$311.03	**T** **I**

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 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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 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. 2015-00355 dated April 11, 2016

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

TERMS AND CONDITIONS (continued) **T**

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.

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. 2016-00370 dated xxxx

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: $2.90 **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

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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. 2016-00370 dated xxxx

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.

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. 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.

D

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.

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.

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:	$3.20 per kVA of Curtailable Billing Demand	**T/R**
Primary Voltage Service:	$3.31 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

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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. 2016-00370 dated xxxx

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.

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 months 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

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 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:

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.

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_{KU} 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:
   $D_1 \leq C_{KU}$; $CAP_i = 0$
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:

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

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

   $D_i > [C_{KU} + C_{QF}]$; $CAP_i = C_{QF}$

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.

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 a 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 block in future billing periods; such credits will not be used to offset net energy consumption in other 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

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.

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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 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

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:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU 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: ______________________________

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:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU 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: ____________

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 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	1.24%

(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	0.48%

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 dated December 20, 2012

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 the Customer's facility in the event that an emergency or unusual occurrence renders the 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	$1.09 per kW/kVA per month	**R**
Primary Distribution	$0.90 per kW/kVA per month	**R**

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-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.

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.

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 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 thirty (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 therefor 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 (1) 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 (1) 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.

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 (1) 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 (1) 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 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; and

TERMS AND CONDITIONS
Economic Development (continued)

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA 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.

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. 2016-00370 dated xxxx

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.

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	$0.03477
	RTOD-Energy	$0.03477
	RTOD-Demand	$0.03477
	VFD	$0.03477
	GS	$0.03504
	AES	$0.03497
	PS Secondary	$0.03572
	PS Primary	$0.03446
	TODS	$0.03527
	TODP	$0.03432

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

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.

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.

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.

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DATE EFFECTIVE: November 4, 2016

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

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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), AES, 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:	$133.18	$206.81	**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.

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DATE EFFECTIVE: January 1, 2017

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

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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
Lexington, Kentucky

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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 May 2011, and the base fuel factor is $0.02892 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. 2012-00552 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
Lexington, Kentucky

Issued by Authority of Orders of the Public
Service Commission in Case No. 2012-00552
dated May 17, 2013 and May 29, 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 Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, 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:

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DATE EFFECTIVE: July 1, 2015

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. 2014-00371 dated June 30, 2015

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, General Service, and All Electric School 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, GS, and AES 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 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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State Regulation and Rates
Lexington, Kentucky

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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 Rate VFD, General Service Rate GS, All Electric School Rate AES, 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.

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 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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State Regulation and Rates
Lexington, Kentucky

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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 KU'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.

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 KU 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, AES, PS, TODS, TODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employ 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 86.8.

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, 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 or 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 electric 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.

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
Lexington, Kentucky

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.

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)	$ 0.00172 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00024 per kWh
DSM Incentive (DSMI)	$ 0.00008 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00100 per kWh
DSM Balance Adjustment (DBA)	$(0.00051) per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00253 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00102 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00030 per kWh
DSM Incentive (DSMI)	$ 0.00004 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00026 per kWh
DSM Balance Adjustment (DBA)	$ 0.00012 per kWh
Total DSMRC for Rate GS	$ 0.00174 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00033 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00058 per kWh
DSM Balance Adjustment (DBA)	$(0.00008) per kWh
Total DSMRC for Rate AES	$ 0.00093 per kWh

Power Service Rate PS*, 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)	$ 0.00034 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00026 per kWh
DSM Balance Adjustment (DBA)	$(0.00029) per kWh
Total DSMRC for Rates PS, TODS, TODP and RTS	$ 0.00042 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
Lexington, Kentucky

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

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; AES; 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.

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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 dated June 30, 2015

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.
4) At its option, a governmental body imposing a franchise fee shall not be billed for that portion of a franchise fee, applied to services designated by the governmental body, that would ultimately be repaid to the governmental body.

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.

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.

Adjustment Clause **HEA**
Home Energy Assistance Program

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 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 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, 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 (12) 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 Customer 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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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. 2016-00370 dated xxxx

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 Customer 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 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 a contract 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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 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 the customer shall obtain from the proper 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 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: 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. 2016-00370 dated xxxx

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 in 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 the 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedules 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 volts three-wire service where network system is available.
2) Three phase 240 volts three-wire service, 120/240 volts four-wire service, 480 volts three-wire service, 120-208Y volts four-wire service, or 277/480Y four-wire service.

PRIMARY VOLTAGES

According to location, 2,400/4160Y volts, 7,200/12,470Y 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 Customer’s electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of 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, 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 a 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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 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 Customer's 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 through the residential meter subject to the conditions set forth below: **T**

   (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.

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 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.

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 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.

TERMS AND CONDITIONS

BILLING

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.

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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 dated December 20, 2012

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 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 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 the 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
Lexington, 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 KAR 5:006, Section 8(1)(d)(2).
3) Company will 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

TERMS AND CONDITIONS

DEPOSITS

RESIDENTIAL (Continued)

5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become 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 KAR 5:006, 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 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 (10%) percent, 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.

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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 KAR 5:006, 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 (10%) percent, 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 become 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 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 this 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 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.

TERMS AND CONDITIONS

Bill Format

Mailed **4/29/16** for Account # **3000-0000-0001**

AMOUNT DUE	DUE DATE
$139.76	5/18/16

KU
a PPL company

BILLING SUMMARY

Previous Balance	121.16
Payment(s) Received	-121.16
Balance as of 4/21/16	**$0.00**
Current Electric Charges	130.63
Current Taxes and Fees	9.13
Total Current Charges as of 4/21/16	**$139.76**
Total Amount Due	**$139.76**

Account Name:	**JOHN SMITH**
Service Address:	100 Deer Crossing Way LEXINGTON KY
Online Payments:	lge-ku.com
Telephone Payments:	(859) 255-0394, press 1-2-3 24 hours a day, $2.25 fee
Customer Service:	(859) 255-0394 M-F, 7am-7pm ET
Walk-in Center:	1 Quality Street Lexington, KY 40507 M-F, 8am-5pm ET

Next read will occur 5/19/16 - 5/21/16 (Meter Read Portion 14)

CURRENT USAGE

ELECTRIC	
Meter Reading Information	**Meter # L200000**
Actual (R) kWh Reading on 4/21/16	10109
Previous (R) kWh Reading on 3/20/16	8698
Current kWh Usage	1411
Meter Multiplier	1
Metered kWh Usage	**1411**

CURRENT CHARGES

ELECTRIC	**Rate:** Residential Service
Basic Service Charge	10.75
Energy Charge ($0.07744 x 1,411 kWh)	109.27
Electric DSM ($0.00376 x 1,411 kWh)	5.31
Fuel Adjustment ($0.00007 x 1,411 kWh)	0.10
Environmental Surcharge (3.950% x $125.43)	4.95
Home Energy Assistance Fund Charge	0.25
Total Charges	**$130.63**

Please return only this portion with your payment. Make checks payable to KU and write your account number on your check.

Amount Due **5/18/16**	**$139.76**
After Due Date, Pay this Amount:	$143.95
WinterCare Donation:	
Total Amount Enclosed:	

Account # **3000-0000-0001**
Service Address: 100 Deer Crossing Way

#926190001 5#

JOHN SMITH
100 DEER CROSSING WAY
LEXINGTON, KY 40509-0000

KU
a PPL company
PO Box 9001954
Louisville, KY 40290-1954

02030000000000100000000143950000013976000000000000028

TERMS AND CONDITIONS

Bill Format

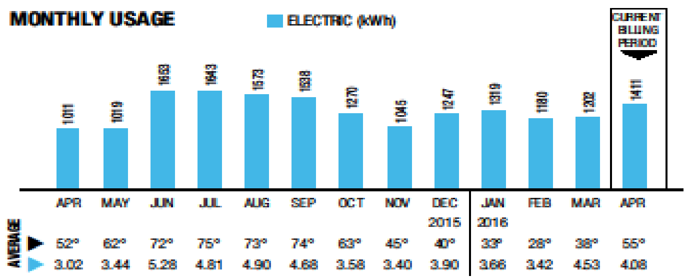
Page 2

Account # **3000-0000-0001**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	**55°**	**53°**
Number of Days Billed	32	32
Avg. Electric Charges per Day	**$4.08**	**$3.02**
Avg. Electric Usage per Day (kWh)	44.09	31.59

MONTHLY USAGE



Taxes & Fees

Rate Increase For School Tax (3.00% x $130.38)	3.91
Franchise Fee-Lexington-Fayette (4.00% x $130.38)	5.22
Total Taxes and Fees	**$9.13**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $4.19

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY
MRU1 431 1654, G000000
P121.16
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
Lexington, 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 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 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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 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.

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 Kentucky Utilities 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.

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) 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 25 kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25 kVA 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

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 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 25 kVA 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 TO 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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 dated June 30, 2015

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND LILNE 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 with the exception of Company's meter.
6) 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.
7) 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.
8) 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

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.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (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 determined by a unit charge of $9.81 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 $23.30 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.
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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: December 31, 2015

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

TERMS AND CONDITIONS

Line Extension Plan

High Density Subdivisions (continued)

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 outlined in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify 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 billing of the monthly electric demand 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.

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Kentucky Utilities 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, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that the 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 the 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 the 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 the 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:

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.

Kentucky Utilities Company
Case No. 2016-00370
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. No. 17
Canceling P.S.C. No. 16

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In seventy-seven counties in the Commonwealth of Kentucky
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
Lexington, Kentucky

P.S.C. No. 18
Canceling P.S.C. No. 17

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In seventy-seven counties in the Commonwealth of Kentucky
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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 17, Second Revision of Original Sheet No. 1
Canceling P.S.C. No. 17, 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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 17, Third Revision of Original Sheet No. 1.1
Canceling P.S.C. No. 17, 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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 5
Canceling P.S.C. No. 17, 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. Three phase service under this rate schedule is restricted to those customers being billed on this rate schedule as of July 1, 2004.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge of:	$ 0.08870 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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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. Three phase service under this rate schedule is restricted to those customers being billed on this rate schedule as of July 1, 2004. **T**

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.05015	$0.03508	$0.08523	**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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 6
Canceling P.S.C. No. 17, 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:	$0.05740 per kWh
On Peak Hours:	$0.27646 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

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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:	$0.05266	**T/R**
On-Peak Hours:	$0.27646	**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
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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 6.1

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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 6.1

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	**T**
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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 7
Canceling P.S.C. No. 17, 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:	$ 0.04370 per kWh
Plus a Demand Charge:	
Off Peak Hours:	$ 3.70 per kW
On Peak Hours:	$13.05 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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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:	$ 0.03508	**T/R**
Plus a Demand Charge per kW:		**T**
Base Hours:	$ 3.44	**T/R**
Peak Hours:	$ 7.87	**T/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

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.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 9
Canceling P.S.C. No. 17, 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:	$ 0.08870 per kWh

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

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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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. **T**

RATE

Basic Service Charge per month:	$22.00			**T/I**
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	**T**
	$0.05015	$0.03508	$0.08523	**R**

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

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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 10
Canceling P.S.C. No. 17, 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. 13, 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:	$ 0.10426 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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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. 13, 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**
	$0.07137	$0.03548	$0.10685	**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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 12
Canceling P.S.C. No. 17, Original Sheet No. 12

Standard Rate **AES**
ALL ELECTRIC SCHOOL

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate is available for secondary and primary service to:

(1) a complex of school buildings on a central campus,
(2) an individual school building, or
(3) an addition to an existing school building.

School buildings, as referred to herein, shall be defined as buildings used as classrooms, laboratories, gymnasiums, libraries, cafeterias, school related offices or for other bona fide school purposes by duly constituted school authorities of Kentucky. Served electrically by Kentucky Utilities Company, such energy requirements include, but are not limited to, lighting, heating, cooling, and water heating. School buildings not receiving every energy requirement electrically shall be separately metered from the above defined service and served under the applicable rate. Other fuels may be used as incidental to and for instructional laboratory and other miscellaneous purposes without affecting the availability of this rate.

At those locations where the school owns its distribution system and makes the service connections to the various buildings and/or load centers, Company shall be given the option of providing service by use of the existing Customer-owned distribution system, or of constructing its own facilities in accordance with the Company's Overhead Construction Standards. In any event, Company's investment in the facilities it provides may be limited to an amount not exceeding twice the estimated annual revenue from Customer's service. Should Company's investment in the facilities required to provide service to Customer exceed twice the revenue anticipated from the service to Customer and at Customer's option, Customer may make a contribution for the difference in the investment required in facilities necessary to provide service and twice the anticipated revenue, so as to receive service under this schedule.

This Rate Schedule is not available to privately operated kindergartens or daycare centers and is restricted to those customers who were qualified for and being served on Rate AES as of July 1, 2011. Because this rate schedule is closed to new customers, 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.

RATE

Basic Service Charge:	$25.00 per meter per month for single-phase service $40.00 per meter per month for three-phase service
Plus an Energy Charge of:	$ 0.08369 per kWh

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 12

Standard Rate **AES**
ALL ELECTRIC SCHOOL

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate is available for secondary and primary service to:

(1) a complex of school buildings on a central campus; **T**
(2) an individual school building; or **T**
(3) an addition to an existing school building.

School buildings, as referred to herein, shall be defined as buildings used as classrooms, laboratories, gymnasiums, libraries, cafeterias, school related offices or for other bona fide school purposes by duly constituted school authorities of Kentucky. Served electrically by Kentucky Utilities Company, such energy requirements include, but are not limited to, lighting, heating, cooling, and water heating. School buildings not receiving every energy requirement electrically shall be separately metered from the above defined service and served under the applicable rate. Other fuels may be used as incidental to and for instructional laboratory and other miscellaneous purposes without affecting the availability of this rate.

At those locations where the school owns its distribution system and makes the service connections to the various buildings and/or load centers, Company shall be given the option of providing service by use of the existing Customer-owned distribution system, or of constructing its own facilities in accordance with the Company's Overhead Construction Standards. In any event, Company's investment in the facilities it provides may be limited to an amount not exceeding twice the estimated annual revenue from Customer's service. Should Company's investment in the facilities required to provide service to Customer exceed twice the revenue anticipated from the service to Customer and at Customer's option, Customer may make a contribution for the difference in the investment required in facilities necessary to provide service and twice the anticipated revenue, so as to receive service under this schedule.

This Rate Schedule is not available to privately operated kindergartens or daycare centers and is restricted to those customers who were qualified for and being served on Rate AES as of July 1, 2011. Because this rate schedule is closed to new customers, 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.

RATE

Basic Service Charge per meter per month:		$ 85.00 single-phase service $140.00 three-phase service		**T/I** **T/I**
Plus an Energy Charge per kWh:	Infrastructure $0.04996	Variable $0.03523	Total $0.08519	**T** **R**

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.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 12.1

Standard Rate **AES**
ALL ELECTRIC SCHOOL

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.

DATE OF ISSUE: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 12.1

Standard Rate **AES**
ALL ELECTRIC SCHOOL

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

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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.

DATE OF ISSUE: November 23, 2016

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State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 15
Canceling P.S.C. No. 17, Original Sheet No. 15

Standard Rate **PS**
POWER SERVICE

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 PSC 13, Fourth Revision of Original Sheet No. 20, Large Power Service, or Fourth Revision of Original Sheet No. 30, Mine Power Service, 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:	$ 0.03572	$ 0.03446
Plus a Demand Charge per kW of:		
Summer Rate: (Five Billing Periods of May through September)	$19.05	$ 19.51
Winter Rate: (All other months)	$16.95	$ 17.41

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 expected load on the system or on facilities specified by Customer.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 15

Standard Rate **PS**
POWER SERVICE

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 PSC 13, Fourth Revision of Original Sheet No. 20, Large Power Service, or Fourth Revision of Original Sheet No. 30, Mine Power Service, 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:	$ 0.03572	$ 0.03472	**T/I**
Plus a Demand Charge per kW:			**T**
Summer Rate: (Five Billing Periods of May through September)	$20.71	$ 20.78	**I**
Winter Rate: (All other months)	$18.43	$ 18.54	**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 expected load 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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 15.1

Standard Rate **PS**

POWER SERVICE

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 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).

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 15.1

Standard Rate **PS**

POWER SERVICE

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 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).

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

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 20
Canceling P.S.C. No. 17, 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:	$ 0.03527
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 6.13
Intermediate Demand Period	$ 4.53
Base Demand Period	$ 5.20

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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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:	$ 0.03531	**T/I**
Plus a Maximum Load Charge per kW:		**T**
Peak Demand Period:	$ 7.81	**T/I**
Intermediate Demand Period:	$ 6.11	**T/I**
Base Demand Period:	$ 3.24	**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 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
Lexington, Kentucky

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Public Service Commission in Case No.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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, at 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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, at 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)

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

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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

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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 20.2

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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 20.2

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

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

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Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 22
Canceling P.S.C. No. 17, 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:	$ 0.03432
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.89
Intermediate Demand Period	$ 4.39
Base Demand Period	$ 3.34

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.

DATE OF ISSUE: December 16, 2015

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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:	$ 0.03433	**T/I**
Plus a Maximum Load Charge per kVA:		**T**
Peak Demand Period:	$ 6.83	**T/I**
Intermediate Demand Period:	$ 5.34	**T/I**
Base Demand Period:	$ 2.92	**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 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 **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

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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 22.1

Standard Rate **TODP**

TIME-OF-DAY PRIMARY SERVICE

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.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 22.1

Standard Rate **TODP**

TIME-OF-DAY PRIMARY SERVICE

DETERMINATION OF MAXIMUM LOAD **T**

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.

T

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 ninety (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, 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. 2016-00370 dated xxxx

TIME-OF-DAY PRIMARY SERVICE

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 ninety (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.

KU Time-of-Day Primary Service Rate TODP is now contained on two pages instead of three pages.

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 25
Canceling P.S.C. No. 17, 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:	$ 0.03357
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 4.73
Intermediate Demand Period	$ 4.63
Base Demand Period	$ 3.10

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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:	$ 0.03363	**T/I**
Plus a Maximum Load Charge per kVA:		**T**
Peak Demand Period:	$ 6.72	**T/I**
Intermediate Demand Period:	$ 5.26	**T/I**
Base Demand Period:	$ 2.12	**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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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 ninety (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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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 ninety (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

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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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 30
Canceling P.S.C. No. 17, 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 Rate FLS schedule of Louisville Gas and Electric 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:	$ 0.03643	$ 0.03344
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 3.01	$ 3.01
Intermediate Demand Period	$ 2.12	$ 2.12
Base Demand Period	$ 2.17	$ 1.42

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.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 Rate FLS schedule of Louisville Gas and Electric 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	$1,500.00	**R/I**
Plus an Energy Charge per kWh:	$ 0.03433	$ 0.03344	**T/R**
Plus a Maximum Load Charge per kVA:			**T**
Peak Demand Period:	$ 6.27	$ 3.51	**T/I**
Intermediate Demand Period:	$ 4.76	$ 2.47	**T/I**
Base Demand Period:	$ 2.60	$ 1.65	**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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 30.1

Standard Rate **FLS**
Fluctuating Load Service

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

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 30.1

Standard Rate **FLS**
Fluctuating Load Service

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

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

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, 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 years with successive one 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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 years with successive one 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

DATE OF ISSUE: November 23, 2016

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

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Kentucky Utilities Company

Standard Rate **FLS**

Fluctuating Load Service

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 KU and LG&E. 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

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

Standard Rate **FLS**

Fluctuating Load Service

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 KU and LG&E. 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: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 35
Canceling P.S.C. No. 17, 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	Monthly Charge Ornamental
High Pressure Sodium					
462/472	Cobra Head	5,800	0.083	$ 9.86	$13.04
463/473	Cobra Head	9,500	0.117	10.28	13.70
464/474	Cobra Head	22,000*	0.242	16.08	19.50
465/475	Cobra Head	50,000*	0.471	25.61	27.37
487	Directional	9,500	0.117	$10.13	
488	Directional	22,000*	0.242	15.42	
489	Directional	50,000*	0.471	21.95	
428	Open Bottom	9,500	0.117	$ 8.87	
Metal Halide					
450	Directional	12,000*	0.150	$16.13	
451	Directional	32,000*	0.350	22.80	
452	Directional	107,800*	1.080	47.70	

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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	Monthly Charge Ornamental	
High Pressure Sodium						
462/472	Cobra Head	5,800	0.083	$ 9.86	$15.65	**I**
463/473	Cobra Head	9,500	0.117	10.79	16.44	**I**
464/474	Cobra Head	22,000*	0.242	16.08	23.40	**I**
465/475	Cobra Head	50,000*	0.471	25.61	32.84	**I**
487	Directional	9,500	0.117	$10.44		**I**
488	Directional	22,000*	0.242	15.42		
489	Directional	50,000*	0.471	21.95		
428	Open Bottom	9,500	0.117	$ 8.87		
Metal Halide						**D**
451	Directional	32,000*	0.350	$22.80		**T**
						D
Light Emitting Diode (LED)						**N**
390	Cobra Head	8,179	0.080	$15.21		**N**
391	Cobra Head	14,166*	0.134	18.42		**N**
392	Cobra Head	23,214*	0.228	28.09		**N**

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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 35.1
Canceling P.S.C. No. 17, Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

OVERHEAD SERVICE (continued)

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.

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

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Decorative Smooth**	**Historic Fluted**
High Pressure Sodium						
467	Colonial	5,800	0.083		$12.14	
468	Colonial	9,500	0.117		12.46	
401/411	Acorn	5,800	0.083		$16.57	$23.63
420/430	Acorn	9,500	0.117		17.01	24.20
414	Victorian	5,800	0.083			$33.87
415	Victorian	9,500	0.117			34.19
492/476	Contemporary	5,800	0.083	$17.12	$18.66	
497/477	Contemporary	9,500	0.117	17.00	23.09	
498/478	Contemporary	22,000*	0.242	19.84	29.73	
499/479	Contemporary	50,000*	0.471	24.15	36.74	
300	Dark Sky	4,000	0.060		$24.72	
301	Dark Sky	9,500	0.117		25.83	

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

RATE (continued)

Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Monthly Charge Fixture Only**
LED (continued)				
393	Open Bottom	5,007	0.050	$10.13

N

OVERHEAD SERVICE (continued)

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.

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

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Decorative Smooth**	**Historic Fluted**
High Pressure Sodium						
467	Colonial	5,800	0.083		$14.57	
468	Colonial	9,500	0.117		14.95	
401/411	Acorn	5,800	0.083		$19.88	$28.36
420/430	Acorn	9,500	0.117		20.41	29.04
414	Victorian	5,800	0.083			$36.70
415	Victorian	9,500	0.117			37.46
492/476	Contemporary	5,800	0.083	$17.12	$22.39	
497/477	Contemporary	9,500	0.117	17.00	27.71	
498/478	Contemporary	22,000*	0.242	19.84	35.68	
499/479	Contemporary	50,000*	0.471	24.15	42.55	
300	Dark Sky	4,000	0.060		$26.46	
301	Dark Sky	9,500	0.117		28.18	

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 35.2
Canceling P.S.C. No. 17, Original Sheet No. 35.2

Standard Rate **LS**
Lighting Service

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Decorative Smooth	Monthly Charge: Historic Fluted
Metal Halide						
490/494	Contemporary	12,000*	0.150	$17.45	$31.42	
491/495	Contemporary	32,000*	0.350	24.68	38.64	
493/496	Contemporary	107,800*	1.080	51.32	65.28	

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

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.

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 35.2

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued) T
RATE T

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Decorative Smooth	
						T
						T
Metal Halide						D
491/495	Contemporary	32,000*	0.350	$24.68	$41.06	T/I
						D
Light Emitting Diode (LED)						N
396	Cobra Head	8,179	0.080		$36.27	
397	Cobra Head	14,166*	0.134		39.47	
398	Cobra Head	23,214*	0.228		49.15	
399	Colonial, 4-Sided	5,665	0.068		$38.32	

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

T

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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

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: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

TERM OF CONTRACT T

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 36
Canceling P.S.C. No. 17, 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 comprising 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). Company has, upon request, furnished poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Fixture and Pole
High Pressure Sodium					
461/471	Cobra Head	4,000	0.060	$ 8.53	$11.73
409	Cobra Head	50,000	0.471	13.56	
426	Open Bottom	5,800	0.083	8.54	
Metal Halide					
454	Directional	12,000	0.150		$20.89
455	Directional	32,000	0.350		27.56
459	Directional	107,800	1.080		52.45
Mercury Vapor					
446/456	Cobra Head	7,000	0.207	$10.77	$13.27
447/457	Cobra Head	10,000	0.294	12.77	14.98
448/458	Cobra Head	20,000	0.453	14.45	16.91
404	Open Bottom	7,000	0.207	11.87	

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 comprising 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.

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

OVERHEAD SERVICE **T**
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). Company has, upon request, furnished poles, of Company's choosing, together with overhead wiring and all other equipment mentioned for overhead service.

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Fixture and Pole	
High Pressure Sodium						
461/471	Cobra Head	4,000	0.060	$10.07	$14.08	I
409	Cobra Head	50,000	0.471	16.27		I
426	Open Bottom	5,800	0.083	8.54		
Metal Halide						
450/454	Directional	12,000*	0.150	$16.13	$20.89	N
455	Directional	32,000*	0.350		27.56	T
452/459	Directional	107,800*	1.080	47.70	52.45	N
Mercury Vapor						
446/456	Cobra Head	7,000	0.207	$11.09	$14.01	I
447/457	Cobra Head	10,000	0.294	13.49	15.82	I
448/458	Cobra Head	20,000	0.453	14.88	17.86	I
404	Open Bottom	7,000	0.207	11.87		

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

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Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 36.1
Canceling P.S.C. No. 17, Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

Incandescent					
421	Tear Drop	1,000	0.102	$ 3.81	
422	Tear Drop	2,500	0.201	5.11	
424/434	Tear Drop	4,000	0.327	7.63	$ 8.67
425	Tear Drop	6,000	0.447	10.19	

Where the location of existing poles was not suitable, or where there were no existing poles for mounting of lights, and Customer requested service under these conditions, Company may have furnished the requested facilities at an additional charge determined under the Excess Facilities Rider.

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				**Monthly Charge**		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Wood Pole**	**Decorative Smooth**	**Historic Fluted**
Metal Halide						
460	Directional	12,000	0.150		$30.10	
469	Directional	32,000	0.350		36.77	
470	Directional	107,800	1.080		61.66	
High Pressure Sodium						
440/410	Acorn	4,000	0.060		$15.11	$22.31
466	Colonial	4,000	0.060		$10.79	
412	Coach	5,800	0.083		$33.87	
413	Coach	9,500	0.117		34.19	

DATE OF ISSUE: December 16, 2015

DATE EFFECTIVE: February 1, 2016

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE				**Monthly Charge**	
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**T T T**
Incandescent					
421	Tear Drop	1,000	0.102	$ 3.81	
422	Tear Drop	2,500	0.201	5.11	
424	Tear Drop	4,000	0.327	7.63	**D**
425	Tear Drop	6,000	0.447	10.19	

Where the location of existing poles was not suitable, or where there were no existing poles for mounting of lights, and Customer requested service under these conditions, Company may have furnished the requested facilities at an additional charge determined under the Excess Facilities Rider.

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				**Monthly Charge**			
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Decorative Smooth**	**Historic Fluted**	**T T**
Metal Halide							
460	Directional	12,000	0.150		$35.23		**I**
469	Directional	32,000	0.350		39.76		**I**
470	Directional	107,800*	1.080		61.66		**T**
490/494	Contemporary	12,000*	0.150	$17.45	$31.42		**N**
493/496	Contemporary	107,800*	1.080	51.32	65.28		**N**
High Pressure Sodium							
440/410	Acorn	4,000	0.060		$18.13	$26.77	**I**
466	Colonial	4,000	0.060		$12.95		**I**
412	Coach	5,800	0.083		$36.70		**I**
413	Coach	9,500	0.117		37.46		**I**

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2017

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 36.2
Canceling P.S.C. No. 17, 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 Decorative Smooth	Monthly Charge Historic Fluted
360	Granville	16,000	0.181	$62.30	

Granville units are restricted to installations for the City of London.

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.

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, and the Company shall initiate service corrections within two (2) business days after such notification 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 Decorative Smooth	
360	Granville	16,000	0.181	$62.30	

T
T

Granville units are restricted to installations for the City of London.

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.

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, and the Company shall initiate service corrections within two (2) business days after such notification by Customer.

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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 36.3

Standard Rate **RLS**
Restricted Lighting Service

TERMS AND CONDITIONS (Continued)

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 36.3

Standard Rate **RLS**
Restricted Lighting Service

TERMS AND CONDITIONS (Continued)

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: July 1, 2015

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

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Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 37
Canceling P.S.C. No. 17, 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
$0.07328 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
a) 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.

b) 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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
$0.07328 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00221 dated December 7, 2015

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 38
Canceling P.S.C. No. 17, 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:	$0.08740 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.

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.

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 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:	$0.09289	**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.

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.

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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE (continued)

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE (continued)

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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:

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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.

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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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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.

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DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 40.1

Standard Rate **PSA** **T**
Pole and Structure Attachment Charges

"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).

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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.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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

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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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 40.3

Standard Rate **CTAC**

Cable Television Attachment Charges

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.

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 it-self 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.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 40.3

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

Pole and Structure Attachment Charges

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.

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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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 40.4

Standard Rate **CTAC**
Cable Television Attachment Charges

Customer shall provide and maintain in an Insurance Company(s) authorized to do business in the Commonwealth of Kentucky, the following:

(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 Kentucky Utilities Company so to guarantee, within the policy limits, the performance by the named insured of the indemnity

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 40.4

Standard Rate **PSA** **T**
Pole and Structure Attachment Charges

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.

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State Regulation and Rates
Lexington, Kentucky

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provisions of the Cable Television Attachment Agreement between the named insured and Kentucky Utilities Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Kentucky Utilities Company."

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.

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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.

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 40.6

Standard Rate **CTAC**
Cable Television Attachment Charges

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.

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 40.6

Standard Rate **PSA** **T**
Pole and Structure Attachment Charges

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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State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 40.7

Standard Rate **CTAC**
Cable Television Attachment Charges

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.

(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.

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State Regulation and Rates
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P.S.C. No. 18, 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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The proposed KU Pole and Structure Attachment Charges Rate PSA (formerly named Rate CTAC) is contained on 20 pages instead of eight pages.

Kentucky Utilities Company

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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Standard Rate **PSA**
Pole and Structure Attachment Charges T

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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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

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

**Issued by Authority of an Order of the
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2016-00370 dated xxxx**

The proposed KU Pole and Structure Attachment Charges Rate PSA (formerly named Rate CTAC) is contained on 20 pages instead of eight pages.

Kentucky Utilities Company

Standard Rate **PSA**
Pole and Structure Attachment Charges T

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.

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Kentucky Utilities Company

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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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(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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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 40.18

Standard Rate **PSA**

Pole and Structure Attachment Charges

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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.

Kentucky Utilities Company

P.S.C. No. 17, 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), AES, 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:	$180.83	$302.41

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

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Kentucky Utilities Company

P.S.C. No. 18, 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), AES, PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles.

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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:	$185.28	$311.03	**T** **I**

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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 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.

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Kentucky Utilities Company

P.S.C. No. 17, 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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Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 41.2

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

TERMS AND CONDITIONS (continued) T

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Kentucky Utilities Company

P.S.C. No. 17, 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: $ 2.88

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

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 11, 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. 2015-00355 dated April 11, 2016

Kentucky Utilities Company

P.S.C. No. 18, 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: $2.90 **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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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.

DATE OF ISSUE: April 15, 2016

DATE EFFECTIVE: April 11, 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. 2015-00355 dated April 11, 2016

Kentucky Utilities Company

P.S.C. No. 18, 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.

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 11, 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. 2015-00355 dated April 11, 2016

Kentucky Utilities Company

P.S.C. No. 17, 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. 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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.

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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.

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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. 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.

D

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. 2016-00370 dated xxxx

KU Special Charges is now contained on two pages instead of one page.

Kentucky Utilities Company

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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 Kentucky Utilities Company is limited to 100 MVA in addition to the contracted curtailable load under P.S.C. No. 14, CSR1 and CSR3 for Kentucky Utilities 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 50.1

Standard Rate Rider **CSR**
Curtailable Service Rider

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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 50.1

Standard Rate Rider **CSR**
Curtailable Service Rider

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:	$3.20 per kVA of Curtailable Billing Demand	**T/R**
Primary Voltage Service:	$3.31 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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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* **T**
Journal on-line for the most recent day for which a price is posted that precedes the **T**
day in which the buy-through occurred. **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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 55
Canceling P.S.C. No. 17, 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 months 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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, 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 months 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
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 17, 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 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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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 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
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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: December 5, 1985

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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: November 23, 2016

DATE EFFECTIVE: December 5, 1985

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

Issued by Authority of an Order of the
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2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: December 5, 1985

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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.

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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.

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

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: December 5, 1985

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. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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_{KU} 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:
   $D_1 \leq C_{KU}$; $CAP_i = 0$
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:

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

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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_{KU} 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:
   $D_1 \leq C_{KU}$; $CAP_i = 0$
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:

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

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 17, 1999

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. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 56.1

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

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

   $D_i > [C_{KU} + C_{QF}]$; $CAP_i = C_{QF}$

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: April 17, 1999

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 56.1

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

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

   $D_i > [C_{KU} + C_{QF}]$; $CAP_i = C_{QF}$

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: April 17, 1999

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. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

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 a 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 block in future billing periods; such credits will not be used to offset net energy consumption in other 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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

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 a 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 block in future billing periods; such credits will not be used to offset net energy consumption in other 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.

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Kentucky Utilities Company

P.S.C. No. 17, 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.

<u>Level 1</u> – 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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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.

<u>Level 1</u> – 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:

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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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Kentucky Utilities Company

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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 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
Lexington, Kentucky

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Kentucky Utilities Company

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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 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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Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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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P.S.C. No. 17, 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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P.S.C. No. 18, 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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P.S.C. No. 17, 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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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.
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P.S.C. No. 17, Original Sheet No. 57.6

Standard Rate Rider **NMS**
Net Metering Service

<u>LEVEL 1</u>

<u>Application for Interconnection and Net Metering</u>
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:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.6

Standard Rate Rider **NMS**
Net Metering Service

<u>LEVEL 1</u>

<u>Application for Interconnection and Net Metering</u>
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:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU 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

DATE EFFECTIVE: November 1, 2010

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. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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:

Kentucky Utilities Company, Attn: Customer Commitment, P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact KU 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 60

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 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	1.24%

(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	0.48%

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 60

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 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	1.24%

(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	0.48%

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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 the Customer's facility in the event that an emergency or unusual occurrence renders the 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	$1.12 per kW/kVA per month
Primary Distribution	$1.11 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-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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 the Customer's facility in the event that an emergency or unusual occurrence renders the 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	$1.09 per kW/kVA per month	**R**
Primary Distribution	$0.90 per kW/kVA per month	**R**

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-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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

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	$12.84	$11.63	$10.58

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

KU Supplemental/Standby Service
Rate SS is proposed to be eliminated.

Kentucky Utilities 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 the 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
Lexington, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00371 dated June 30, 2015**

KU Supplemental/Standby Service
Rate SS is proposed to be eliminated.

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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: November 23, 2016

DATE EFFECTIVE: January 1, 2013

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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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 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 thirty (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 therefor 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 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 thirty (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 therefor 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: 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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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: March 1, 2000

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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: November 23, 2016

DATE EFFECTIVE: March 1, 2000

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. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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 (1) 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 (1) 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
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 18, 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 (1) 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 (1) 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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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 (1) 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 (1) 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: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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 (1) 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 (1) 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: January 1, 2013

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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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

<u>Brownfield Development</u>

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 greater where the customer takes service from existing Company facilities.

<u>Economic Development</u>

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

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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

<u>Brownfield Development</u>

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 greater where the customer takes service from existing Company facilities.

<u>Economic Development</u>

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

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS
Economic Development (continued)

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA 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.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS
Economic Development (continued)

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA 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.

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. 2016-00370 dated xxxx

Kentucky Utilities Company

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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

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

DATE EFFECTIVE: July 1, 2015

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. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, 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
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)

Rate Schedule	Credit per kWh
RS	$0.03477
RTOD-Energy	$0.03477
RTOD-Demand	$0.03477
VFD	$0.03477
GS	$0.03504
AES	$0.03497
PS Secondary	$0.03572
PS Primary	$0.03446
TODS	$0.03527
TODP	$0.03432

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
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 18, 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
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)

Rate Schedule	Credit per kWh
RS	$0.03477
RTOD-Energy	$0.03477
RTOD-Demand	$0.03477
VFD	$0.03477
GS	$0.03504
AES	$0.03497
PS Secondary	$0.03572
PS Primary	$0.03446
TODS	$0.03527
TODP	$0.03432

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

Kentucky Utilities Company

P.S.C. No. 17, 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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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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.

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

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Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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.

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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

Kentucky Utilities Company

P.S.C. No. 18, 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.

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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
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 17, 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

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

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Kentucky Utilities Company

P.S.C. No. 18, 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.

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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

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Kentucky Utilities Company

P.S.C. No. 17, 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), AES, 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:	$132.68	$206.11

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
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 18, 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), AES, 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:	$133.18	$206.81	**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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 75.1

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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 75.1

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.

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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
Lexington, Kentucky

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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
Lexington, Kentucky

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

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
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 17, 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: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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: January 1, 2013

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. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 17, 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 May 2011, and the base fuel factor is \$0.02892 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. 2012-00552 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
Lexington, Kentucky

Issued by Authority of Orders of the Public Service Commission in Case No. 2012-00552 dated May 17, 2013 and May 29, 2013

Kentucky Utilities Company

P.S.C. No. 18, 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).

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(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. 2012-00552 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
Lexington, Kentucky

Issued by Authority of Orders of the Public Service Commission in Case No. 2012-00552 dated May 17, 2013 and May 29, 2013

Kentucky Utilities Company

P.S.C. No. 17, 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 Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, 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."

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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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, General Service, and All Electric School 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, GS, and AES 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 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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State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 18, 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, General Service, and All Electric School 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, GS, and AES 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.

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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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State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 17, 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 Rate VFD, General Service Rate GS, All Electric School Rate AES, 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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State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 18, 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 Rate VFD, General Service Rate GS, All Electric School Rate AES, 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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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 86.3

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 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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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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 KU'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
Lexington, Kentucky

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P.S.C. No. 18, Original Sheet No. 86.4

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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Kentucky Utilities Company

P.S.C. No. 17, 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 KU 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.

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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 KU 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.

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Kentucky Utilities Company

P.S.C. No. 17, 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, AES, PS, TODS, TODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employ 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 86.8.

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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Kentucky Utilities Company

P.S.C. No. 18, 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, AES, PS, TODS, TODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation
The Commercial Load Management / Demand Conservation Program employ 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 86.8.

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- 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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Kentucky Utilities Company

P.S.C. No. 17, 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, 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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Kentucky Utilities Company

P.S.C. No. 18, 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, 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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Kentucky Utilities Company

P.S.C. No. 17, First Revision to Original Sheet No. 86.8
Canceling P.S.C. 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 or 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 electric 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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, 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 or heat pump, water-heater (40 gallon minimum) and/or swimming pool pump switch installed.
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- 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.

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

Kentucky Utilities Company

P.S.C. No. 17, 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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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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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Kentucky Utilities Company

P.S.C. No. 17, Third Revision of Original Sheet No. 86.10
Canceling P.S.C. No. 17, 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)	$ 0.00172 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00024 per kWh
DSM Incentive (DSMI)	$ 0.00008 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00100 per kWh
DSM Balance Adjustment (DBA)	$(0.00051) per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00253 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00102 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00030 per kWh
DSM Incentive (DSMI)	$ 0.00004 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00026 per kWh
DSM Balance Adjustment (DBA)	$ 0.00012 per kWh
Total DSMRC for Rate GS	$ 0.00174 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00033 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00058 per kWh
DSM Balance Adjustment (DBA)	$(0.00008) per kWh
Total DSMRC for Rate AES	$ 0.00093 per kWh

Power Service Rate PS*, 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)	$ 0.00034 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00026 per kWh
DSM Balance Adjustment (DBA)	$(0.00029) per kWh
Total DSMRC for Rates PS, TODS, TODP and RTS	$ 0.00042 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

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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. 2015-00398 dated March 31, 2016

Kentucky Utilities Company

P.S.C. No. 18, 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)	$ 0.00172 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00024 per kWh
DSM Incentive (DSMI)	$ 0.00008 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00100 per kWh
DSM Balance Adjustment (DBA)	$(0.00051) per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00253 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00102 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00030 per kWh
DSM Incentive (DSMI)	$ 0.00004 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00026 per kWh
DSM Balance Adjustment (DBA)	$ 0.00012 per kWh
Total DSMRC for Rate GS	$ 0.00174 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00033 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00058 per kWh
DSM Balance Adjustment (DBA)	$(0.00008) per kWh
Total DSMRC for Rate AES	$ 0.00093 per kWh

Power Service Rate PS*, 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)	$ 0.00034 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00026 per kWh
DSM Balance Adjustment (DBA)	$(0.00029) per kWh
Total DSMRC for Rates PS, TODS, TODP and RTS	$ 0.00042 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

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

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Kentucky Utilities Company

P.S.C. No. 17, Second Revision of Original Sheet No. 87
Canceling P.S.C. No. 17, 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; AES; 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00026 dated August 8, 2016

Kentucky Utilities Company

P.S.C. No. 18, 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 **T**
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; AES; 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
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Lexington, Kentucky

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Kentucky Utilities Company

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Canceling P.S.C. No. 17, 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: August 15, 2016

DATE EFFECTIVE: August 31, 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. 2016-00026 dated August 8, 2016

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00026 dated August 8, 2016

Kentucky Utilities Company

P.S.C. No. 17, 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:

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.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 88

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

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

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, 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.
4) At its option, a governmental body imposing a franchise fee shall not be billed for that portion of a franchise fee, applied to services designated by the governmental body, that would ultimately be repaid to the governmental body.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: May 26, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 90

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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).

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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: May 26, 2013

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

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 90.1

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 91

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 95

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- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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**

COMPANY AS A FEDERAL CONTRACTOR

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 96.1

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, 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 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, 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 (12) months.

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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 Customer 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: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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 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, 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 (12) 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 Customer 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

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to Customer 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 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 a contract 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 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

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, 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.

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Company installs facilities to supply power to Customer at or near unity power factor.

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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 the customer shall obtain from the proper 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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 97.3

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 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.

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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 in 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, 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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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 in 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: 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. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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 the 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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

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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 the 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

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedules 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 volts three-wire service where network system is available.
2) Three phase 240 volts three-wire service, 120/240 volts four-wire service, 480 volts three-wire service, 120-208Y volts four-wire service, or 277/480Y four-wire service.

PRIMARY VOLTAGES

According to location, 2,400/4160Y volts, 7,200/12,470Y 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 Customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of 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, 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 a 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 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

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Non-Residential Service -

1) Single phase 120/240 volts three-wire service, or 120/208Y volts three-wire service where network system is available.
2) Three phase 240 volts three-wire service, 120/240 volts four-wire service, 480 volts three-wire service, 120-208Y volts four-wire service, or 277/480Y four-wire service.

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   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to a 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.
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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 17, 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 Customer's 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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 Customer's 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 through the residential meter subject to the conditions set forth below: T

   (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

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

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.

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Kentucky Utilities Company

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

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Kentucky Utilities Company

P.S.C. No. 17, 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 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.

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 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.

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Kentucky Utilities Company

P.S.C. No. 18, 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**

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

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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.

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 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.

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Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 101.1

TERMS AND CONDITIONS

BILLING

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.

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.

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P.S.C. No. 18, Original Sheet No. 101.1

TERMS AND CONDITIONS

BILLING

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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.

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Kentucky Utilities Company

P.S.C. No. 17, 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 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."

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P.S.C. No. 18, Original Sheet No. 101.2

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Kentucky Utilities Company

P.S.C. No. 17, 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 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 the 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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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 101.3

TERMS AND CONDITIONS

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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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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 17, 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 KAR 5:006, Section 8(1)(d)(2).
3) Company will 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.

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State Regulation and Rates
Lexington, Kentucky

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P.S.C. No. 18, Original Sheet No. 102

TERMS AND CONDITIONS

DEPOSITS

GENERAL

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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 KAR 5:006, Section 8(1)(d)(2).
3) Company will 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.

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P.S.C. No. 17, 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 become 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 KAR 5:006, 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 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 (10%) percent, 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.

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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 KAR 5:006, 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 (10%) percent, 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 become 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: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 become 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 KAR 5:006, 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 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 (10%) percent, 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.

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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 KAR 5:006, 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 (10%) percent, 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 become 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

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

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Kentucky Utilities Company

P.S.C. No. 17, 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 this 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 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.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 this 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 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.

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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. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 104
Canceling P.S.C. No. 17, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

Mailed **4/29/16** for Account # **3000-0000-0001**

KU. a PPL company

AMOUNT DUE **$139.76** | DUE DATE **5/18/16**

BILLING SUMMARY

Previous Balance	121.16
Payment(s) Received	-121.16
Balance as of 4/21/16	**$0.00**
Current Electric Charges	130.63
Current Taxes and Fees	9.13
Total Current Charges as of 4/21/16	**$139.76**
Total Amount Due	**$139.76**

Account Name:	JOHN SMITH
Service Address:	100 Deer Crossing Way LEXINGTON KY
Online Payments:	lge-ku.com
Telephone Payments:	(859) 255-0394, press 1-2-3 24 hours a day, $2.25 fee
Customer Service:	(859) 255-0394 M-F, 7am-7pm ET
Walk-in Center:	1 Quality Street Lexington, KY 40507 M-F, 8am-5pm ET

Next read will occur 5/19/16 - 5/21/16 (Meter Read Portion 14)

CURRENT USAGE

ELECTRIC	
Meter Reading Information	**Meter # L200000**
Actual (R) kWh Reading on 4/21/16	10109
Previous (R) kWh Reading on 3/20/16	8698
Current kWh Usage	1411
Meter Multiplier	1
Metered kWh Usage	**1411**

CURRENT CHARGES

ELECTRIC	**Rate:** Residential Service
Basic Service Charge	10.75
Energy Charge ($0.07744 x 1,411 kWh)	109.27
Electric DSM ($0.00376 x 1,411 kWh)	5.31
Fuel Adjustment ($0.00007 x 1,411 kWh)	0.10
Environmental Surcharge (3.950% x $125.43)	4.95
Home Energy Assistance Fund Charge	0.25
Total Charges	**$130.63**

Please return only this portion with your payment. Make checks payable to KU and write your account number on your check.

Amount Due **5/18/16**	**$139.76**
After Due Date, Pay this Amount:	$143.95
WinterCare Donation:	
Total Amount Enclosed:	

Account # **3000-0000-0001**
Service Address: 100 Deer Crossing Way

#926190001 5#

JOHN SMITH
100 DEER CROSSING WAY
LEXINGTON, KY 40509-0000

KU. a PPL company
PO Box 9001954
Louisville, KY 40290-1954

020300000000001000000001439500000139760000000000028

DATE OF ISSUE: March 30, 2016

DATE EFFECTIVE: April 29, 2016

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

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 104

TERMS AND CONDITIONS
Bill Format

Mailed **4/29/16** for Account # **3000-0000-0001**

KU. a PPL company

AMOUNT DUE **$139.76** | DUE DATE **5/18/16**

BILLING SUMMARY

Previous Balance	121.16
Payment(s) Received	-121.16
Balance as of 4/21/16	**$0.00**
Current Electric Charges	130.63
Current Taxes and Fees	9.13
Total Current Charges as of 4/21/16	**$139.76**
Total Amount Due	**$139.76**

Account Name:	JOHN SMITH
Service Address:	100 Deer Crossing Way LEXINGTON KY
Online Payments:	lge-ku.com
Telephone Payments:	(859) 255-0394, press 1-2-3 24 hours a day, $2.25 fee
Customer Service:	(859) 255-0394 M-F, 7am-7pm ET
Walk-in Center:	1 Quality Street Lexington, KY 40507 M-F, 8am-5pm ET

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Current kWh Usage	1411
Meter Multiplier	1
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Home Energy Assistance Fund Charge	0.25
Total Charges	**$130.63**

Please return only this portion with your payment. Make checks payable to KU and write your account number on your check.

Amount Due **5/18/16**	**$139.76**
After Due Date, Pay this Amount:	$143.95
WinterCare Donation:	
Total Amount Enclosed:	

Account # **3000-0000-0001**
Service Address: 100 Deer Crossing Way

#926190001 5#

JOHN SMITH
100 DEER CROSSING WAY
LEXINGTON, KY 40509-0000

KU. a PPL company
PO Box 9001954
Louisville, KY 40290-1954

020300000000001000000001439500000139760000000000028

DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

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

Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 104.1
Canceling P.S.C. No. 17, Original Sheet No. 104.1

TERMS AND CONDITIONS
Bill Format

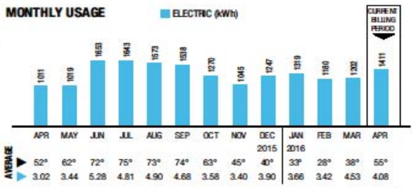
Page 2

Account # **3000-0000-0001**

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	55°	53°
Number of Days Billed	32	32
Avg. Electric Charges per Day	**$4.08**	**$3.02**
Avg. Electric Usage per Day (kWh)	44.09	31.59

MONTHLY USAGE



Taxes & Fees

Rate Increase For School Tax (3.00% x $130.38)	3.91
Franchise Fee-Lexington-Fayette (4.00% x $130.38)	5.22
Total Taxes and Fees	**$9.13**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $4.19

Rate Schedules
For a copy of your rate schedule, visit lge-ku.com or call our Customer Service Department.

OFFICE USE ONLY
MRU1 431 1654, G000000
P121.16
PF:Y eB:P

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DATE EFFECTIVE: April 29, 2016

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

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

Page 2

Account # **3000-0000-0001**

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	THIS YEAR	LAST YEAR
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Number of Days Billed	32	32
Avg. Electric Charges per Day	**$4.08**	**$3.02**
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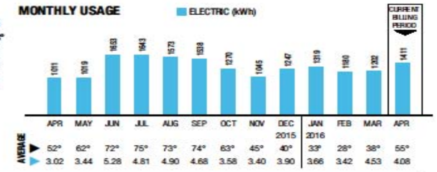

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Rate Increase For School Tax (3.00% x $130.38)	3.91
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DATE OF ISSUE: November 23, 2016

DATE EFFECTIVE: April 29, 2016

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

Kentucky Utilities Company

P.S.C. No. 17, 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 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 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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 105

TERMS AND CONDITIONS

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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:

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities 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 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

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

TERMS AND CONDITIONS

Discontinuance of Service

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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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated xxxx

Kentucky Utilities Company

P.S.C. No. 17, 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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 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.

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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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 Kentucky Utilities 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: July 10, 2015

DATE EFFECTIVE: July 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, 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 Kentucky Utilities 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.
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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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) 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 25 kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25 kVA 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: July 10, 2015

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106.1

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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 25 kVA 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 TO 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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, 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 25 kVA 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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DATE OF ISSUE: November 23, 2016

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

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Kentucky Utilities Company

P.S.C. No. 17, Original Sheet No. 106.3

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND LILNE 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 with the exception of Company's meter.
6) 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.
7) 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.
8) 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

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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106.3

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND LILNE EXTENSIONS

General (continued)

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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.

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

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Kentucky Utilities Company

P.S.C. No. 17, First Revision of Original Sheet No. 106.4
Canceling P.S.C. No. 17, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (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 determined by a unit charge of $9.81 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 $23.30 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.
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.

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (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
Lexington, Kentucky

Kentucky Utilities Company

TERMS AND CONDITIONS

Line Extension Plan

High Density Subdivisions (continued)

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 outlined in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify 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 billing of the monthly electric demand 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

TERMS AND CONDITIONS

Line Extension Plan

High Density Subdivisions (continued)

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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
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 17, 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 Kentucky Utilities 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, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that the 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 the 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 the 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.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 107

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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DATE OF ISSUE: November 23, 2016

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

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Kentucky Utilities Company

P.S.C. No. 17, 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 the 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
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 107.1

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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Kentucky Utilities Company

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: January 8, 2007

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010

Kentucky Utilities Company

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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Kentucky Utilities Company

P.S.C. No. 17, 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.

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State Regulation and Rates
Lexington, Kentucky

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P.S.C. No. 18, Original Sheet No. 107.3

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

CURTAILMENT PROCEDURES (continued)

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Lexington, Kentucky

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Kentucky Utilities Company
Case No. 2016-00370
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 KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**)))))**	**CASE NO. 2016-00370**

CERTIFICATE OF NOTICE

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 Kentucky Utilities Company ("KU" or "Company"), a utility furnishing retail electric 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 rates, terms, conditions and tariffs of KU, and that notice to the public of the filing of the application has been completed 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 the offices and places of business of the Company in the territory affected thereby, to-wit, at the following places:

Barlow	Maysville
Campbellsville	Middlesboro
Carrollton	Morehead
Danville	Morganfield
Earlington	Mt. Sterling
Eddyville	Paris
Elizabethtown	Richmond
Georgetown	Shelbyville
Greenville	Somerset

Harlan	Versailles
Lexington	Winchester
London	

and that the same will be kept open to public inspection at said offices and places of business 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 KU'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, KU 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, KU posted on its website a complete copy of KU's application in this case.

Beginning on November 23, 2016, KU 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, KU 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
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, Kentucky Utilities Company is seeking approval by the Public Service Commission of an adjustment of electric rates and charges proposed to become effective on and after January 1, 2017.

KU 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:	$ 0.08870	
Infrastructure		$ 0.05015
Variable		$ 0.03508
Total		$ 0.08523

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	$ 0.05740	$ 0.05266
On-Peak Hours	$ 0.27646	$ 0.27646

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

Current

Basic Service Charge per Month:	$10.75
Plus an Energy Charge per kWh:	$ 0.04370
Plus a Demand Charge per kW:	
Off-Peak Hours	$ 3.70
On-Peak Hours	$13.05

Proposed

Basic Service Charge per Month:	$22.00
Plus an Energy Charge per kWh:	$ 0.03508
Plus a Demand Charge per kW:	
Base Hours	$ 3.44
Peak Hours	$ 7.87

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:	$ 0.08870	
Infrastructure		$ 0.05015
Variable		$ 0.03508
Total		$ 0.08523

General Service – Rate GS

Single Phase	**Current**	**Proposed**
Basic Service Charge per Month	$25.00	$31.50
Plus an Energy Charge per kWh	$ 0.10426	
Infrastructure		$ 0.07137
Variable		$ 0.03548
Total		$ 0.10685
Three Phase		
Basic Service Charge per Month	$40.00	$50.40
Plus an Energy Charge per kWh	$ 0.10426	
Infrastructure		$ 0.07137
Variable		$ 0.03548
Total		$ 0.10685

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.

All Electric School – Rate AES

Single Phase	**Current**	**Proposed**
Basic Service Charge per Month	$25.00	$85.00
Plus an Energy Charge per kWh	$ 0.08369	
Infrastructure		$ 0.04996
Variable		$ 0.03523
Total		$ 0.08519
Three Phase		
Basic Service Charge per Month	$40.00	$140.00
Plus an Energy Charge per kWh	$ 0.08369	
Infrastructure		$ 0.04996
Variable		$ 0.03523
Total		$ 0.08519

Power Service – Rate PS

Secondary Service	**Current**	**Proposed**
Basic Service Charge per Month	$90.00	$90.00
Plus an Energy Charge per kWh	$ 0.03572	$ 0.03572

Plus a Demand Charge per kW per month of billing demand		
Summer Rate (May through September)	$19.05	$20.71
Winter Rate (All Other Months)	$16.95	$18.43
Primary Service	**Current**	**Proposed**
Basic Service Charge per Month	$200.00	$240.00
Plus an Energy Charge per kWh	$ 0.03446	$ 0.03472
Plus a Demand Charge per kW per month of billing demand		
Summer Rate (May through September)	$ 19.51	$ 20.78
Winter Rate (All Other Months)	$ 17.41	$ 18.54

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	$ 0.03527	$ 0.03531
Plus a Maximum Load Charge per kW per month		
Peak Demand Period	$ 6.13	$ 7.81
Intermediate Demand Period	$ 4.53	$ 6.11
Base Demand Period	$ 5.20	$ 3.24

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	$ 0.03432	$ 0.03433
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 5.89	$ 6.83
Intermediate Demand Period	$ 4.39	$ 5.34
Base Demand Period	$ 3.34	$ 2.92

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	$ 0.03357	$ 0.03363
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 4.73	$ 6.72
Intermediate Demand Period	$ 4.63	$ 5.26
Base Demand Period	$ 3.10	$ 2.12

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	$ 0.03643	$ 0.03433
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 3.01	$ 6.27
Intermediate Demand Period	$ 2.12	$ 4.76
Base Demand Period	$ 2.17	$ 2.60

Transmission Service	**Current**	**Proposed**
Basic Service Charge per Month	$1,000.00	$1,500.00
Plus an Energy Charge per kWh	$ 0.03344	$ 0.03344
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 3.01	$ 3.51
Intermediate Demand Period	$ 2.12	$ 2.47
Base Demand Period	$ 1.42	$ 1.65

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		
462 Cobra Head – 5,800 Lumen – Fixture Only	$ 9.86	$ 9.86
472 Cobra Head – 5,800 Lumen – Ornamental	$13.04	$15.65
463 Cobra Head – 9,500 Lumen – Fixture Only	$10.28	$10.79
473 Cobra Head – 9,500 Lumen – Ornamental	$13.70	$16.44
464 Cobra Head – 22,000 Lumen – Fixture Only*	$16.08	$16.08
474 Cobra Head – 22,000 Lumen – Ornamental*	$19.50	$23.40
465 Cobra Head – 50,000 Lumen – Fixture Only*	$25.61	$25.61
475 Cobra Head – 50,000 Lumen – Ornamental*	$27.37	$32.84
487 Directional – 9,500 Lumen – Fixture Only	$10.13	$10.44
488 Directional – 22,000 Lumen – Fixture Only*	$15.42	$15.42
489 Directional – 50,000 Lumen – Fixture Only*	$21.95	$21.95
428 Open Bottom – 9,500 Lumen – Fixture Only	$ 8.87	$ 8.87
Metal Halide		
450 Directional – 12,000 Lumen – Fixture Only	$16.13	Move to RLS
451 Directional – 32,000 Lumen – Fixture Only	$22.80	$22.80
452 Directional – 107,800 Lumen – Fixture Only	$47.70	Move to RLS
Light Emitting Diode (LED)		
390 Cobra Head – 8,179 Lumen – Fixture Only	N/A	$15.21
391 Cobra Head – 14,166 Lumen – Fixture Only*	N/A	$18.42
392 Cobra Head – 23,214 Lumen – Fixture Only*	N/A	$28.09
393 Open Bottom – 5,007 Lumen – Fixture Only	N/A	$10.13

	Rate Per Light Per Month	
UNDERGROUND SERVICE	**Current**	**Proposed**
High Pressure Sodium		
467 Colonial – 5,800 Lumen – Decorative	$12.14	$14.57
468 Colonial – 9,500 Lumen – Decorative	$12.46	$14.95
401 Acorn – 5,800 Lumen – Smooth Pole	$16.57	$19.88

411 Acorn – 5,800 Lumen – Fluted Pole	$23.63	$28.36
420 Acorn – 9,500 Lumen – Smooth Pole	$17.01	$20.41
430 Acorn – 9,500 Lumen – Fluted Pole	$24.20	$29.04
414 Victorian 5,800 Lumen – Fluted Pole	$33.87	$36.70
415 Victorian 9,500 Lumen – Fluted Pole	$34.19	$37.46
476 Contemporary – 5,800 Lumen – Fixture/Pole	$18.66	$22.39
492 Contemporary – 5,800 Lumen – 2nd Fixture	$17.12	$17.12
477 Contemporary – 9,500 Lumen – Fixture/Pole	$23.09	$27.71
497 Contemporary – 9,500 Lumen – 2nd Fixture	$17.00	$17.00
478 Contemporary– 22,000 Lumen – Fixture/Pole*	$29.73	$35.68
498 Contemporary– 22,000 Lumen – 2nd Fixture*	$19.84	$19.84
479 Contemporary– 50,000 Lumen – Fixture/Pole*	$36.74	$42.55
499 Contemporary– 50,000 Lumen – 2nd Fixture*	$24.15	$24.15
300 Dark Sky – 4,000 Lumen	$24.72	$26.46
301 Dark Sky – 9,500 Lumen	$25.83	$28.18
Metal Halide		
490 Contemporary – 12,000 Lumen – Fixture Only	$17.45	Move to RLS
494 Contemporary – 12,000 Lumen – Smooth Pole	$31.42	Move to RLS
491 Contemporary – 32,000 Lumen – Fixture Only	$24.68	$24.68
495 Contemporary – 32,000 Lumen – Smooth Pole	$38.64	$41.06
493 Contemporary – 107,800 Lumen – Fixture Only	$51.32	Move to RLS
496 Contemporary – 107,800 Lumen – Smooth Pole	$65.28	Move to RLS
Light Emitting Diode (LED)		
396 Cobra Head – 8,179 Lumen – Fixture/Pole	N/A	$36.27
397 Cobra Head – 14,166 Lumen – Fixture/Pole*	N/A	$39.47
398 Cobra Head – 23,214 Lumen – Fixture/Pole*	N/A	$49.15
399 Colonial, 4Sided – 5,665 Lumen – Fixture/Pole	N/A	$38.32

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 comprising 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.

OVERHEAD SERVICE	Rate Per Light Per Month Current	Proposed
High Pressure Sodium		
461 Cobra Head – 4,000 Lumen – Fixture Only	$ 8.53	$10.07
471 Cobra Head – 4,000 Lumen – Fixture & Pole	$11.73	$14.08
409 Cobra Head – 50,000 Lumen – Fixture Only*	$13.56	$16.27
426 Open Bottom – 5,800 Lumen – Fixture Only	$ 8.54	$ 8.54
Metal Halide		
450 Directional – 12,000 Lumen – Fixture Only	Moved from LS	$16.13
454 Directional – 12,000 Lumen – Flood Fixture & Pole	$20.89	$20.89
455 Directional – 32,000 Lumen – Flood Fixture & Pole*	$27.56	$27.56
452 Directional – 107,800 Lumen – Fixture Only*	Moved from LS	$47.70
459 Directional – 107,800 Lumen – Flood Fixture & Pole*	$52.45	$52.45
Mercury Vapor		
446 Cobra Head – 7,000 Lumen – Fixture Only	$10.77	$11.09
456 Cobra Head – 7,000 Lumen – Fixture & Pole	$13.27	$14.01
447 Cobra Head – 10,000 Lumen – Fixture Only	$12.77	$13.49
457 Cobra Head – 10,000 Lumen – Fixture & Pole	$14.98	$15.82
448 Cobra Head – 20,000 Lumen – Fixture Only	$14.45	$14.88
458 Cobra Head – 20,000 Lumen – Fixture & Pole	$16.91	$17.86
404 Open Bottom – 7,000 Lumen – Fixture Only	$11.87	$11.87
Incandescent		
421 Tear Drop – 1,000 Lumen – Fixture Only	$ 3.81	$ 3.81
422 Tear Drop – 2,500 Lumen – Fixture Only	$ 5.11	$ 5.11
424 Tear Drop – 4,000 Lumen – Fixture Only	$ 7.63	$ 7.63
434 Tear Drop – 4,000 Lumen – Fixture & Pole	$ 8.67	Eliminated
425 Tear Drop – 6,000 Lumen – Fixture Only	$10.19	$10.19

UNDERGROUND SERVICE	Rate Per Light Per Month Current	Proposed
Metal Halide		
460 Direct – 12,000 Lumen – Flood Fixture & Pole	$30.10	$35.23
469 Direct – 32,000 Lumen – Flood Fixture & Pole*	$36.77	$39.76
470 Direct – 107,800 Lumen – Flood Fixture & Pole*	$61.66	$61.66
490 Contemporary – 12,000 Lumen – Fixture Only	Moved from LS	$17.45
494 Contemporary – 12,000 Lumen – Smooth Pole	Moved from LS	$31.42
493 Contemporary – 107,800 Lumen – Fixture Only*	Moved from LS	$51.32
496 Contemporary – 107,800 Lumen – Smooth Pole*	Moved from LS	$65.28
High Pressure Sodium		
440 Acorn – 4,000 Lumen – Flood Fixture & Pole	$15.11	$18.13
410 Acorn – 4,000 Lumen – Fluted Pole	$22.31	$26.77
466 Colonial – 4,000 Lumen – Smooth Pole	$10.79	$12.95
412 Coach – 5,800 Lumen – Smooth Pole	$33.87	$36.70
413 Coach – 9,500 Lumen – Smooth Pole	$34.19	$37.46

	Current	Proposed
360 Granville Pole and Fixture, 16000L	$62.30	$62.30

Lighting Energy Service - Rate LE

	Current	Proposed
Energy Charge per kWh:	$0.07328	$0.07328

Traffic Energy Service - Rate TE

Current

Basic Service Charge per Month:	$4.00 per delivery
Energy Charge per kWh:	$0.08740

Proposed

Basic Service Charge per Month:	$4.00 per delivery point
Energy Charge per kWh:	$0.09289

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 KU. 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, to 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 KU 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 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 - EVSE

	Current	Proposed
Monthly Charging Unit:		
Single Charger	$180.83	$185.28
Dual Charger	$302.41	$311.03

Electric Vehicle Charging – EVC

	Current	Proposed
Fee Per Hour	$2.88	$2.90

Curtailable Service Rider – CSR

Primary	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$ 6.50	$ 3.31
Non-Compliance Charge Per kVA:	$16.00	$16.00
Transmission	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$ 6.40	$ 3.20
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 Kentucky Utilities Company is limited to 100 MVA in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Kentucky Utilities 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	1.24%	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	0.48%	0.48%

Standard Rider for Redundant Capacity Charge – Rider RC

Capacity Reservation Charge per Month:	**Current (Per kW/kVA)**	**Proposed (Per kW/kVA)**
Secondary Distribution	$1.12	$1.09
Primary Distribution	$1.11	$0.90

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	$12.84
Primary	$11.63
Transmission	$10.58

Proposed

Company proposes to eliminate this Rider.

Electric Vehicle Supply Equipment – Rider EVSE-R

Monthly Charging Unit Fee	**Current**	**Proposed**
Single Charger	$132.68	$133.18
Dual Charger	$206.11	$206.81

Returned Payment Charge

Current Rate $10.00
Proposed Rate $10.00

Meter Test Charge

Current Rate $75.00
Proposed Rate $75.00

Disconnecting and Reconnecting 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

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 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 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, GS, and AES.

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, AES, 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; AES; 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; AES; 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.

Contracted 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

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. 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

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. 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.

Kentucky Utilities 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, All Electric School Rate AES, 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, Electric Vehicle Supply Equipment Rate EVSE, 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.

Complete copies of the proposed tariffs containing text changes and proposed rates may be obtained by contacting Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, 1-800-981-0600, or visiting Kentucky Utilities Company's website at www.lge-ku.com.

The foregoing rates reflect a proposed annual increase in revenues of approximately 6.4% to Kentucky Utilities 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	1,179	36,998,263	5.94	7.16	5.94
Residential Time-of-Day	1,171	1,800	5.91	6.21	5.91
General Service	1,805	12,094,454	5.06	12.10	5.06
All Electric School	21,341	777,151	5.34	109.21	5.34
Power Service	41,288	10,184,158	5.04	181.52	5.04
Time-of-Day Secondary	225,256	6,865,948	5.55	925.48	5.55
Time-of-Day Primary	1,241,109	17,335,551	6.61	5,224.70	6.61
Retail Transmission	4,160,317	6,022,822	6.71	16,730.06	6.71
Fluctuating Load	46,076,466	2,235,014	7.25	186,251.16	7.25
Outdoor Lights	61	1,866,484	6.14	0.92	6.14
Lighting Energy	9,307	0	0.00	0.00	0.00
Traffic Energy	160	8,175	4.71	0.88	4.71
PSA (presently CTAC)	N/A	0	0.00	0.00	0.00
Rider - CSR	N/A	8,688,375	49.95	80,447.92	49.95

Notice is further given that a person may examine this application at the offices of Kentucky Utilities Company, 100 Quality Street, Lexington, Kentucky, and may also be examined at Kentucky Utilities 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. 2016-00370.

The rates contained in this notice are the rates proposed by Kentucky Utilities 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.

Kentucky Utilities Company
c/o LG&E and KU Energy LLC
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
1-800-981-0600

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 KU Territory

Barbourville Mountain Advocate
Bardstown Kentucky Standard
Bardwell Carlisle County News
Bardwell Carlisle Weekly
Beattyville Enterprise
Beattyville Three Forks Tradition
Bedford Trimble Banner
Berea Citizen
Brooksville Bracken County News
Brownsville Edmonson News
Calhoun McLean County News
Campbellsville Central Kentucky News Journal
Carlisle Mercury
Carrollton News Democrat
Cave City Barren Progress
Central City Leader News
Central City Times Argus
Clinton Hickman County Gazette
Columbia Adair Progress
Commonwealth Journal
Corbin Times Tribune
Cumberland Tri City News
Cynthiana Democrat
Dawson Springs Progress
Eddyville Herald Ledger
Elizabethtown News Enterprise
Falmouth Outlook
Flemingsburg Gazette
Florence Boone County
Frankfort State Journal
Fulton Leader
Georgetown News Graphic
Glasgow Daily Times
Greensburg Record Herald
Harlan Enterprise
Harrodsburg Herald
Hartford Ohio County Times
Henderson Gleaner
Hickman County Times
Hickman Courier
Hodgenville Larue Herald
Hopkinsville Kentucky New Era
Irvine Citizen Voice and Times
Irvine Estill Tribune

Lagrange Oldham Era
Lancaster Central Record
Lawrenceburg Anderson News
Lebanon Enterprise
Leitchfield News Gazette
Leitchfield The Record
Lexington Herald Leader
Liberty Casey County News
London Sentinel Echo
Louisville Courier Journal
Madisonville Messenger
Manchester Enterprise
Marion Crittenden Press
Maysville Ledger Independent
Middlesboro Daily News
Morehead News
Morganfield Union County Advocate
Mt. Sterling Advocate
Mt. Vernon Signal
Munfordville Hart County News
New Castle Henry County Local
Nicholasville Jessamine Journal
Owensboro Messenger Inquirer
Owenton News Herald
Owingsville Bath Outlook
Paducah Sun
Paris Bourbon Citizen
Pineville Sun
Princeton Times Leader
Providence Journal Enterprise
Richmond Register
Robertson County News
Russell Springs Times Journal
Sebree Banner
Shelbyville Sentinel News
Shepherdsville Pioneer News
Smithland Livingston Ledger
Springfield Sun
Stanford Interior Journal
Sturgis News
Taylorsville Spencer Magnet
The Advocate Messenger
Versailles Woodford Sun
Warsaw Gallatin County News
Whitley City McCreary Voice
Wickliffe Advance Yeoman

Williamsburg News Journal
Williamstown Grant County News
Winchester Sun

Exhibit C

Customer Bill Insert
General Statement

NOTICE TO CUSTOMERS OF KENTUCKY UTILITIES COMPANY

PLEASE TAKE NOTICE that, in a November 23, 2016 Application, Kentucky Utilities Company ("KU") is seeking approval by the Kentucky Public Service Commission of an adjustment of its rates and charges to become effective on and after January 1, 2017.

The proposed rates reflect a proposed annual increase in revenues of approximately 6.4% to KU.

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	1,179	36,998,263	5.94	7.16	5.94
Residential Time-of-Day Energy	1,171	1,800	5.91	6.21	5.91
General Service	1,805	12,094,454	5.06	12.10	5.06
All Electric School	21,341	777,151	5.34	109.21	5.34
Power Service	41,288	10,184,158	5.04	181.52	5.04
Time-of-Day Secondary	225,256	6,865,948	5.55	925.48	5.55
Time-of-Day Primary	1,241,109	17,335,551	6.61	5,224.70	6.61
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Outdoor Lights	61	1,866,484	6.14	0.92	6.14
Lighting Energy	9,307	0	0.00	0.00	0.00
Traffic Energy	160	8,175	4.71	0.88	4.71
PSA (presently CTAC)	N/A	0	0.00	0.00	0.00
Rider – CSR	N/A	8,688,375	49.95	80,447.92	49.95

KU is also proposing changes in the text of some of its rate schedules and other tariff provisions, including its terms and conditions for electric service. Complete copies of the proposed tariffs containing the proposed text changes and rates may be obtained by contacting, Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, 40202, 1-800-981-0600, or by visiting KU's website at www.lge-ku.com.

Notice is further given that a person may examine this application at the offices of KU, 100 Quality Street, Lexington, Kentucky, and may also be examined at KU'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. 2016-00370.

The rates contained in this notice are the rates proposed by KU, 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 KU's website at www.lge-ku.com, or through the Public Service Commission's website at http://psc.ky.gov.

Kentucky Utilities Company
c/o LG&E and KU Energy LLC
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
1-800-981-0600

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602
502-564-3940

Kentucky Utilities Company
Case No. 2016-00370
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.

a PPL company

RECEIVED

OCT 21 2016

PUBLIC SERVICE
COMMISSION

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

Robert M. Conroy
Vice President
T 502-627-3324
F 502-217-4985
robert.conroy@lge-ku.com

October 21, 2016

RE: ***Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity* – Case No. 2016-00370**

Dear Dr. Mathews:

Please take notice that Kentucky Utilities Company ("KU") intends to file on or after November 23, 2016, an application for a general adjustment in its electric rates, including changes to its electric tariffs, and for Certificates of Public Convenience and Necessity. This application will be supported by a fully forecasted test period ending June 30, 2018.

KU 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)

KU
a PPL company

RECEIVED

OCT 21 2016

PUBLIC SERVICE
COMMISSION

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

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 Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity* – Case No. 2016-00_370_**

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. Kentucky Utilities Company intends to file on or after November 23, 2016, an application for a general adjustment in its electric rates, including changes to its electric 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)

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, Kentucky Utilities Company gives notice of its intent to file an application for Adjustment of Electric 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.

Kentucky Utilities 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 Robt 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

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
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:

KU acknowledges this requirement.

Kentucky Utilities Company
Case No. 2016-00370
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:

KU acknowledges this requirement.

Kentucky Utilities Company
Case No. 2016-00370
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.

KENTUCKY UTILITIES COMPANY

Reconciliation of Capitalization and Rate Base

Line No.	Description	13 Month Average Total Company Balance	13 Month Average Kentucky Jurisdictional	13 Month Average Other Jurisdictional
1	Rate Base Percentage (Schedule J-1.1/J-1.2)		89.28%	10.72%
2	Capitalization:			
3	Common Equity	$ 2,788,572,734		
4	Long-Term Debt	2,315,890,751		
5	Short-Term Debt	129,187,211		
6	Subtotal	$ 5,233,650,696	$ 4,672,603,341	$ 561,047,355
7	Adjustments to Capitalization:			
8	Investment in EEI	(504,066)	(450,030)	(54,036)
9	Investment in OVEC and Other	(1,221,313)	(1,090,388)	(130,925)
10	Environmental Compliance Plans		(1,025,233,404)	-
11	Demand Side Management Plans		(7,028,789)	-
12	Subtotal	(1,725,379)	(1,033,802,611)	(184,961)
13				
14	Total Adjusted Capitalization (Schedule J-1.1/J-1.2)	$ 5,231,925,316	$ 3,638,800,730	$ 560,862,394
15				
16	Assets per books not included in rate base:			
17	Net ARO Assets		(166,187,055)	
18	Cash and Temporary Investments	(5,061,030)	(4,518,488)	(542,542)
19	Accounts Receivable	(133,452,975)	(119,146,816)	(14,306,159)
20	Other Current Assets	(108,402,713)	(96,781,943)	(11,620,771)
21	Deferred Regulatory Assets	(491,795,924)	(439,075,401)	(52,720,523)
22	Other Deferred Debits	(53,925,376)	(48,144,576)	(5,780,800)
23	Subtotal	(792,638,019)	(873,854,278)	(84,970,796)
24				
25	Liabilities per books not included in rate base:			
26	Other Deferred Credits	6,310,542	5,634,052	676,490
27	Regulatory Liabilities	142,182,266	126,940,328	15,241,939
28	ARO Liabilities	367,386,595	328,002,752	39,383,843
29	Other Current Liabilities	236,555,821	211,197,037	25,358,784
30	Accumulated Provision for Pension & Postretirement	102,706,057	91,695,968	11,010,089
31	Accumulated Deferred Income Taxes	6,769,078	6,043,433	725,645
32	Subtotal	861,910,359	769,513,569	92,396,791
33				
34	Items not included in rate base:			
35	Environmental Compliance Cash Working Capital		2,661,475	-
36				
37	Items included in rate base:			
38	Cash Working Capital Formula	117,152,090	106,348,560	8,142,055
39	Capitalization / Rate Base Allocation Differences	-	(4,390,295)	4,390,295
40	Subtotal	117,152,090	101,958,265	12,532,350
41				
42	Total Reconciliation	186,424,431	279,030	19,958,345
43				
44	Total Rate Base (Schedule B-1)	$ 5,418,349,747	$ 3,639,079,760	$ 580,820,739

Kentucky Utilities Company
Case No. 2016-00370
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
- Robert M. Conroy
- William Steven Seelye
- Christopher M. Garrett
- John J. Spanos

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
Capital Expenditure Budget
Years 2016-2019

	Projected Capital Expenditures			
Category of Spend	**2016**	**2017**	**2018**	**2019**
Generation	182,045,350	260,520,295	345,528,672	245,806,562
Transmission	74,482,354	108,616,484	112,240,087	126,189,949
Distribution	94,902,146	109,232,671	116,493,032	120,088,070
Customer Services	10,787,450	42,789,160	83,760,188	71,734,056
IT & Other	30,562,250	26,066,848	20,785,738	21,028,426
Total	**392,779,550**	**547,225,458**	**678,807,717**	**584,847,062**

-

Kentucky Utilities Company
Case No. 2016-00370
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 KU'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 KU's forecast period are contained in the written direct testimony of Daniel K. Arbough and David S. Sinclair filed with KU's application and are also otherwise quantified, explained and properly supported in the following documents attached to this Filing Schedule. All confidential 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. [This line intentionally left blank.]	
E. [This line intentionally left blank.]	
F. [This line intentionally left blank.]	
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

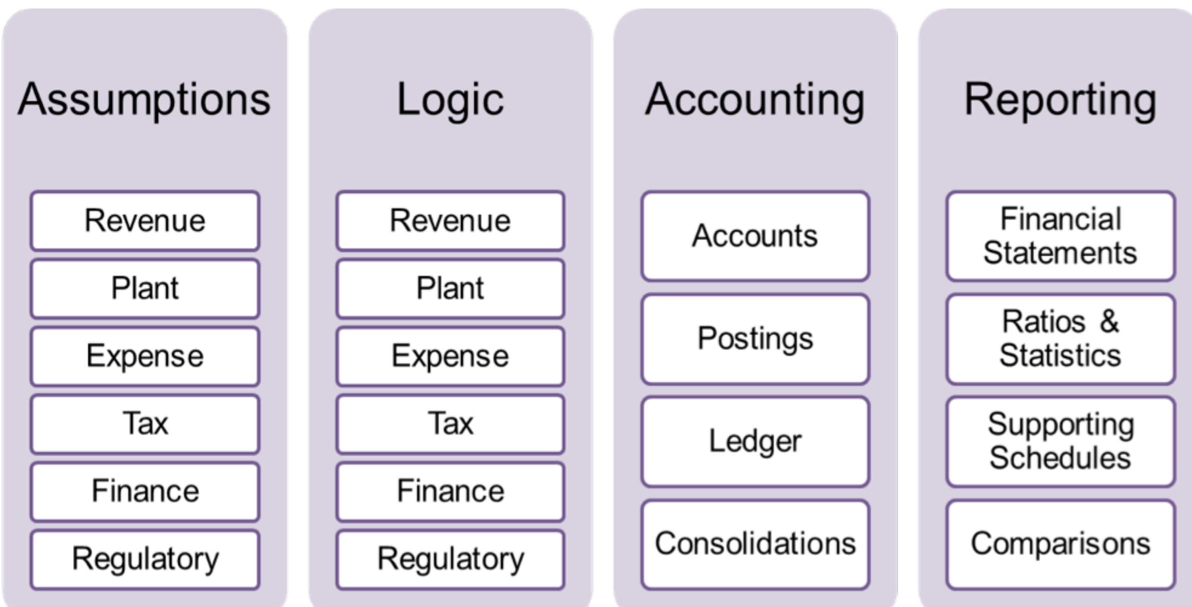
1. <u>General</u>

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]

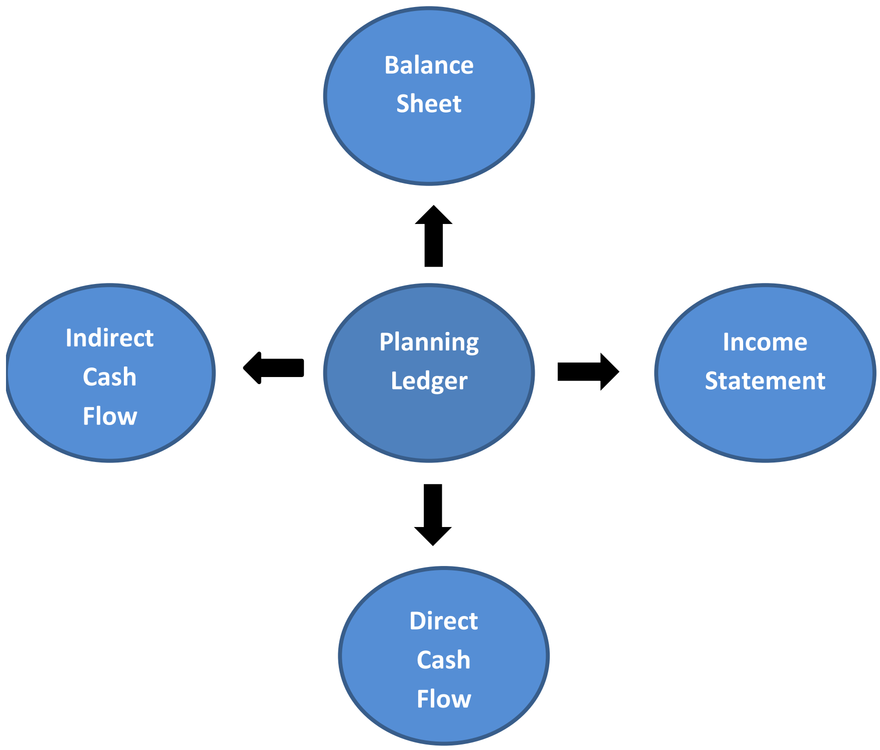
Planning assumptions are managed in UI. UI is superior to an Excel based model because it allows for sharing assumptions in a common database. UI tracks changes to assumptions and maintains a record of who made the change and when.

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.

<u>Planning Ledger Flow Chart</u>



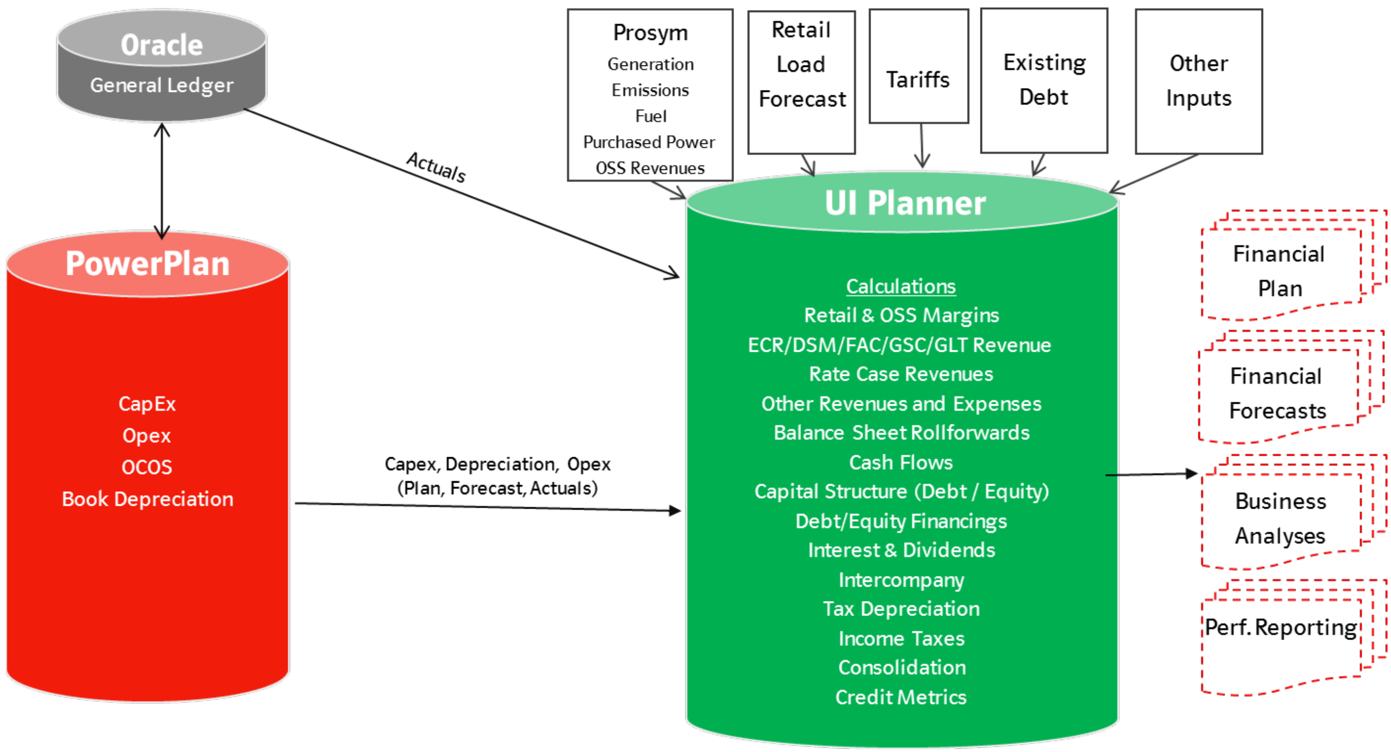
Each month actual balances are imported from the Oracle General Ledger (GL) to update UI with the latest balances and to compare the budget and revised forecast to actuals. The actuals imported into UI are compared to the trial balance in Oracle monthly to ensure completeness and accuracy.

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.

<u>Financial Planning Software Flow Diagram</u>



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. Generation Forecast, Off-System Sales (OSS) and Other Cost of Sales (COS)

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. <u>Pension & Postretirement</u>

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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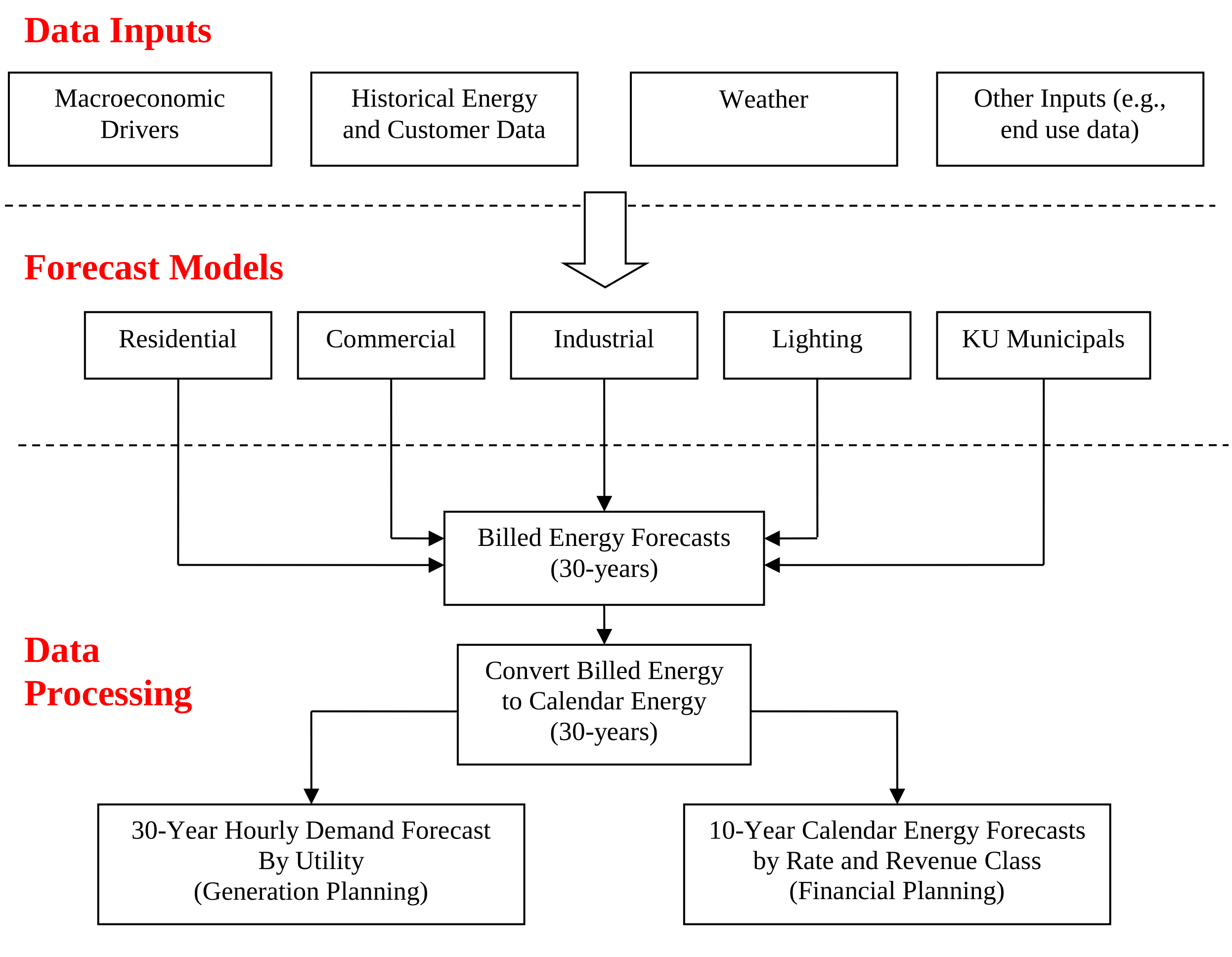
1. Introduction

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.

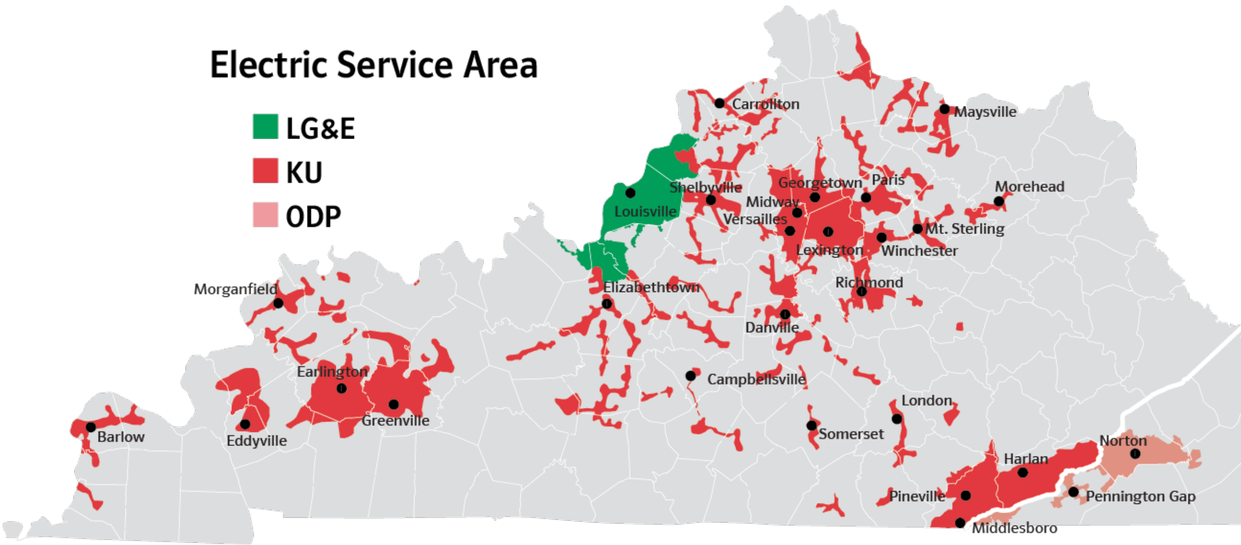
Table 1 – Summary of Forecast Data Inputs

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:

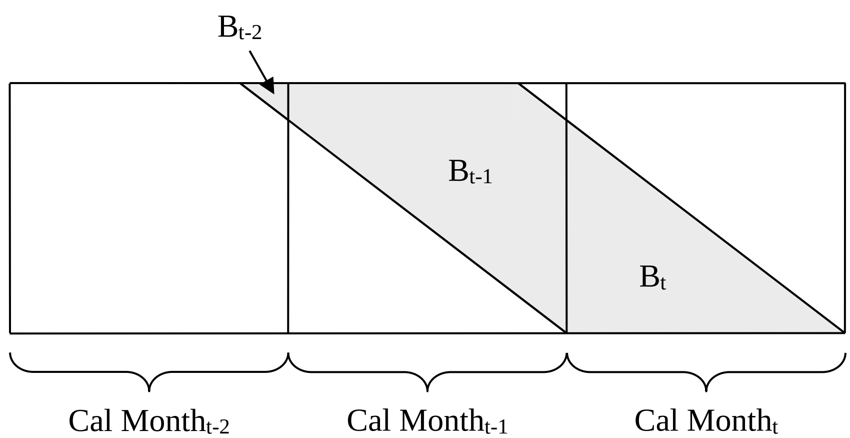
1. Billed-to-Calendar Energy Conversion
2. Rate Code and Revenue Class Allocation
3. Hourly Energy Requirements Forecast

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]

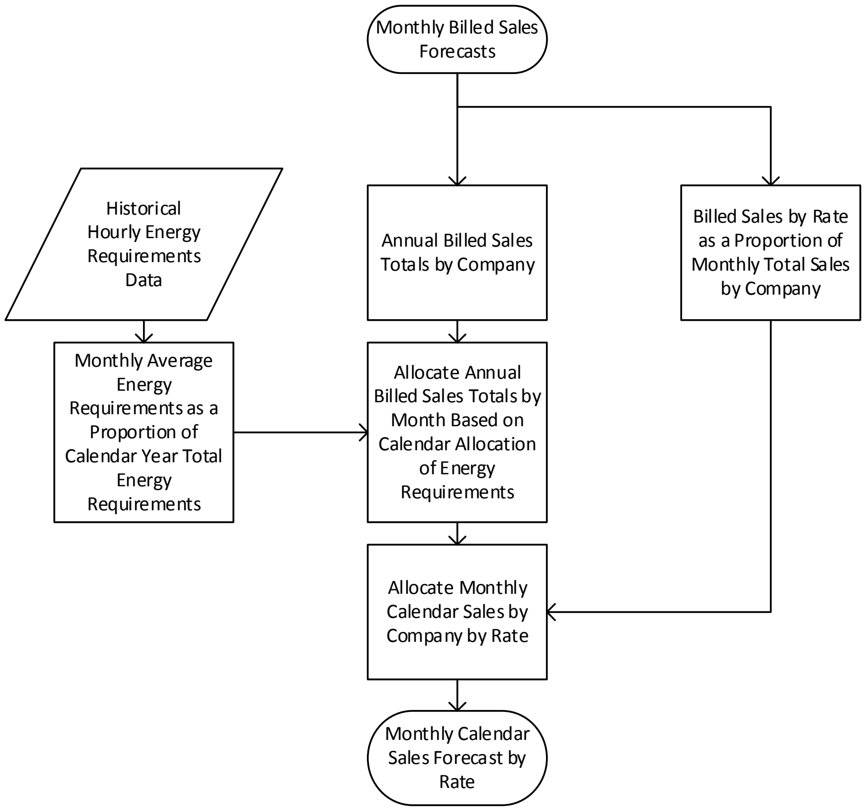
Figure 3 – Billed and Calendar Energy



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:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \qquad (4)$$

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:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \qquad (5)$$

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:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \qquad (6)$$

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,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \qquad (10)$$

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:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{15}$$

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.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{09}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{16}$$
$$\left(TenYearMovingAverageElectric\Pr ice\right)^{\lambda} \times \left(TenYearMovingAverageGas\Pr ice\right)^{\kappa}$$

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:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.10} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09}}\right)^{\phi} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09}}\right)^{\lambda} \qquad (17)$$

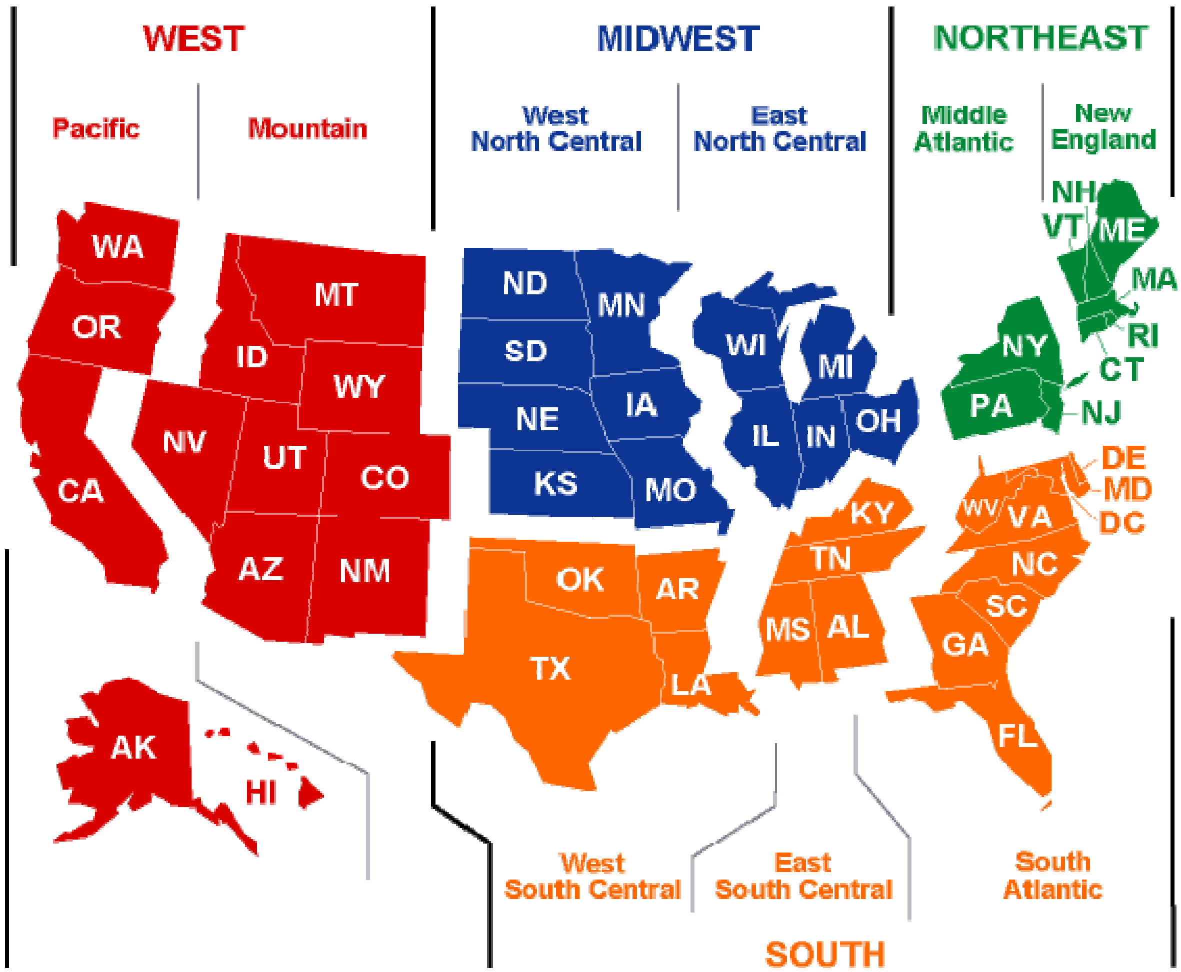
The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \qquad (18)$$

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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \text{Other}_{y,m} \tag{1}$$

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.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

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:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left({CoolShare_y}/{Eff_y} \right)}{\left({CoolShare_{04}}/{Eff_{04}} \right)} \tag{8}$$

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:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} \Big/ Eff_y^{Type}}{Share_{04}^{Type} \Big/ Eff_{04}^{Type}} \right) \tag{12}$$

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:

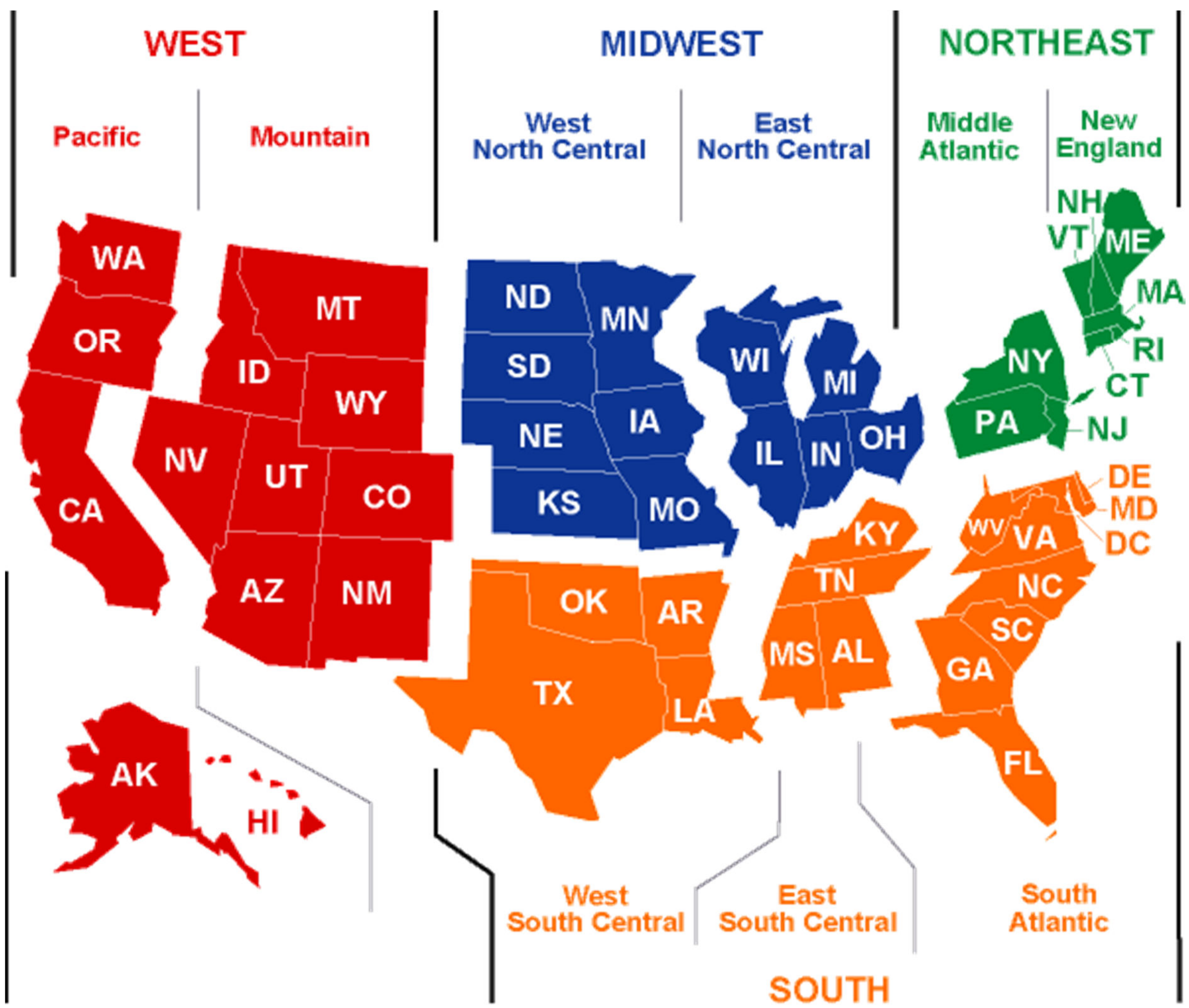
$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}}\right)^{-0.18} \tag{14}$$

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 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

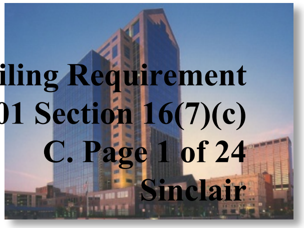
Company	***Revenue Class***	***Rate Class***
	Wholesale	Muni-Paris Muni-Primary Muni-Transmission
LG&E	Commercial	CPS-Pri CPS-Sec CTOD-Pri CTOD-Sec GS IPS-Sec ITOD-Pri ITOD-Sec LES RS Unmetered
	Industrial	CPS-Sec CTOD-Sec GS IPS-Pri IPS-Sec ITOD-Pri ITOD-Sec RS RTS Unmetered
	Lighting	GS LES TES Unmetered
	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

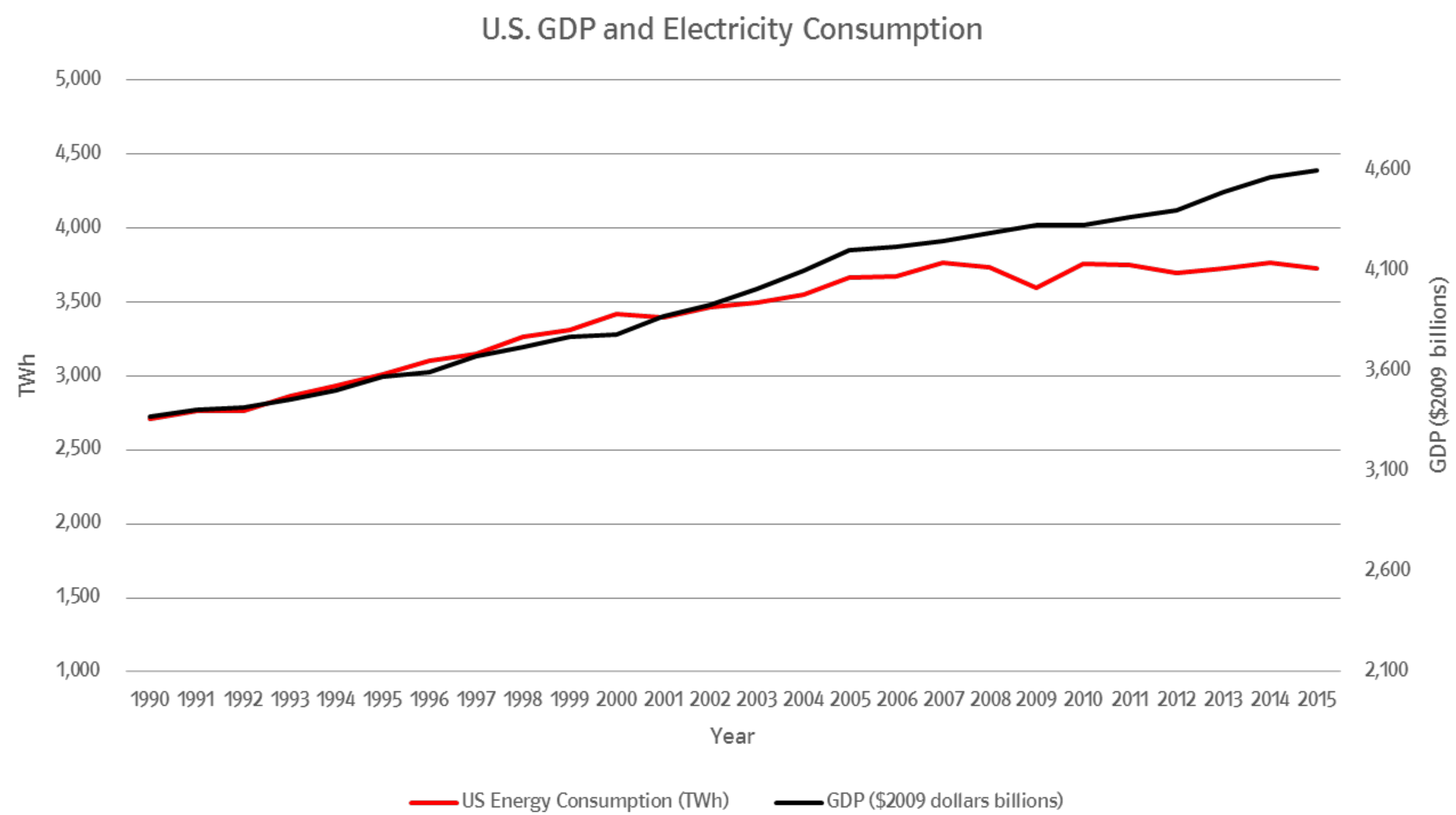
PPL companies

2017 Business Plan Electric Sales Forecast

July 11, 2016



US electricity demand has remained flat from 2010-2015



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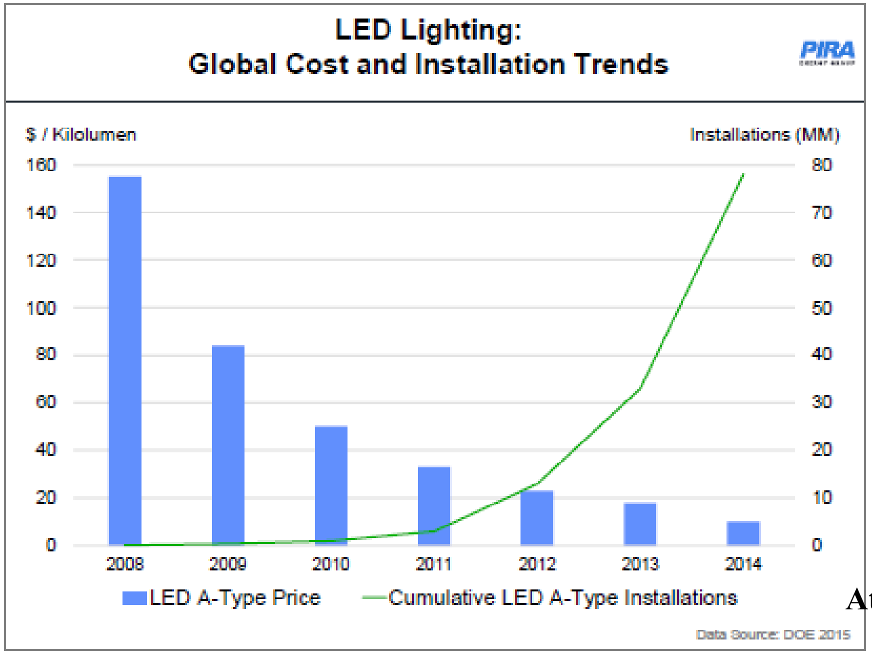
LG&E KU PPL companies

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*

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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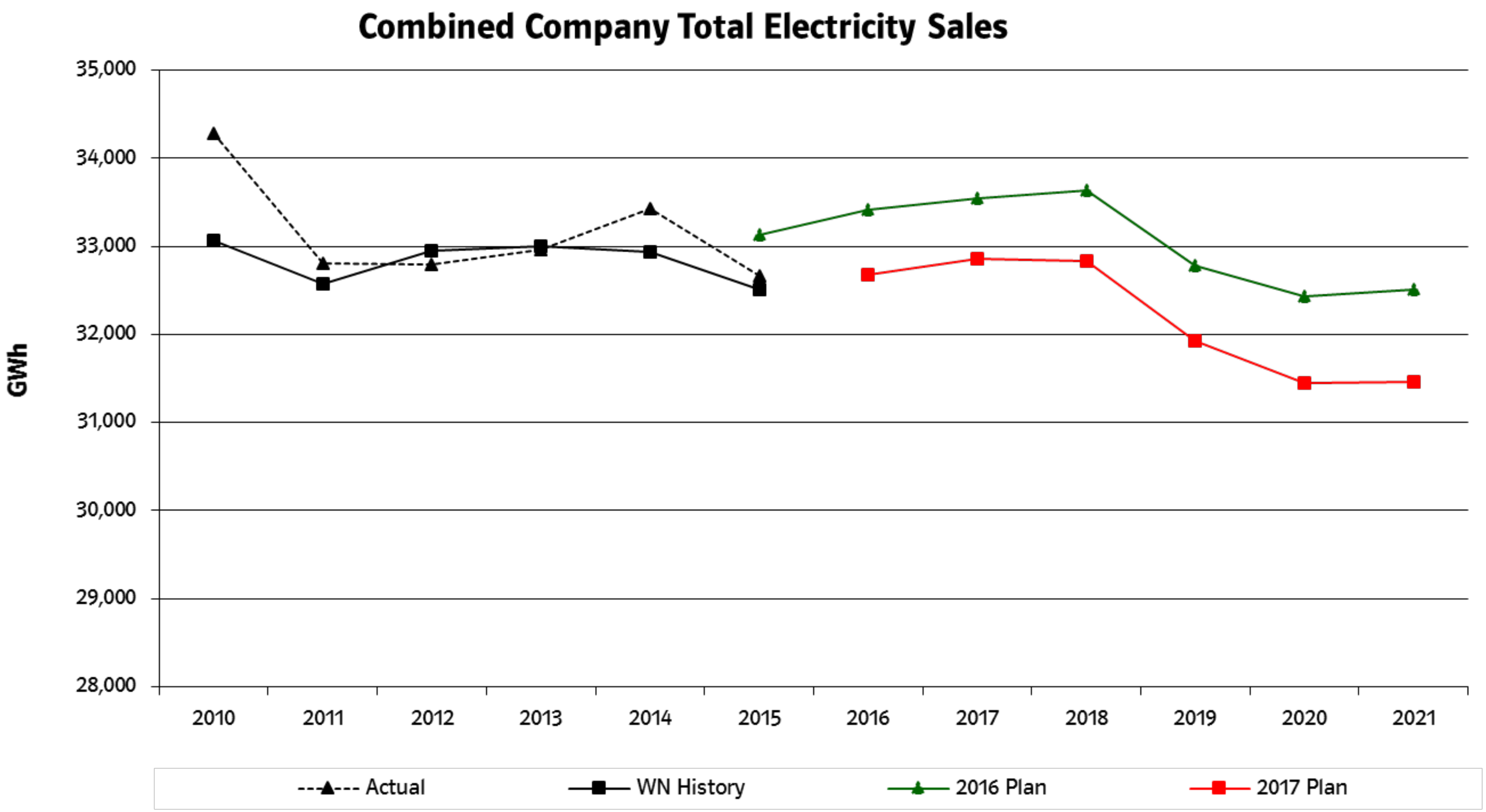
2017 Plan 2-3% lower through 2021



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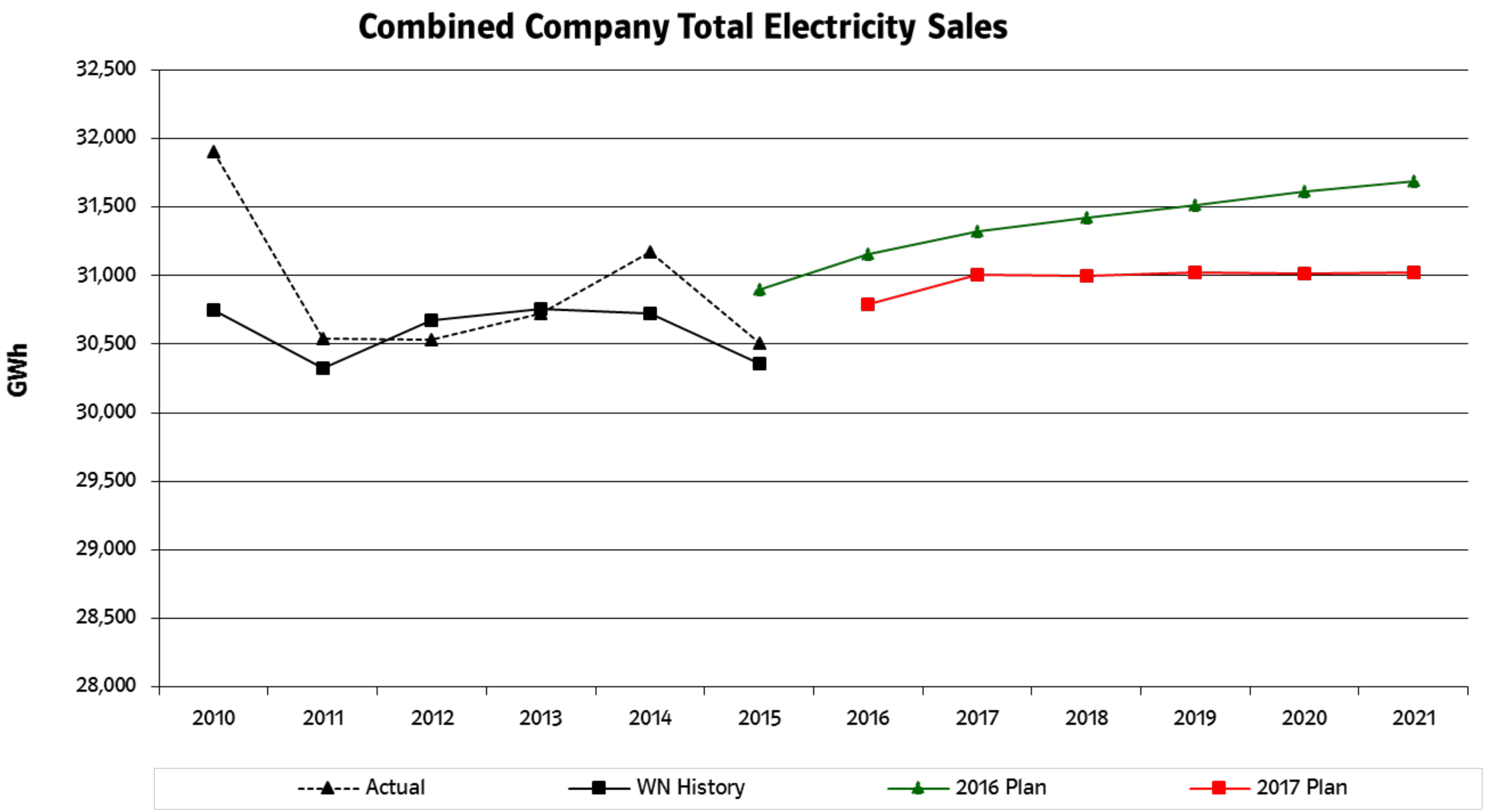
LG&E KU
PPL companies

2017 Plan lower than 2016 Plan with slower growth



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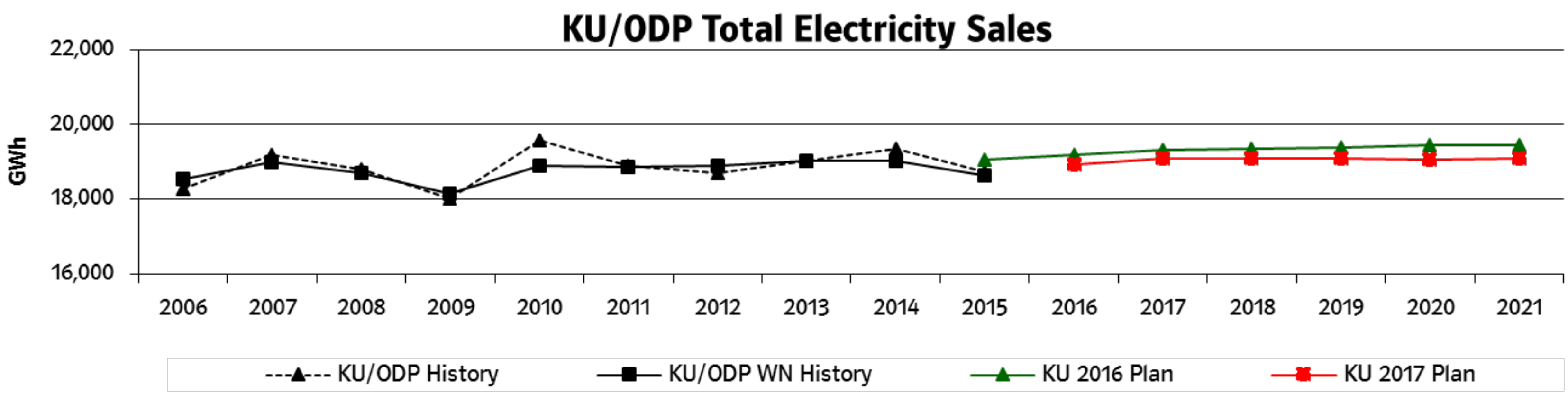
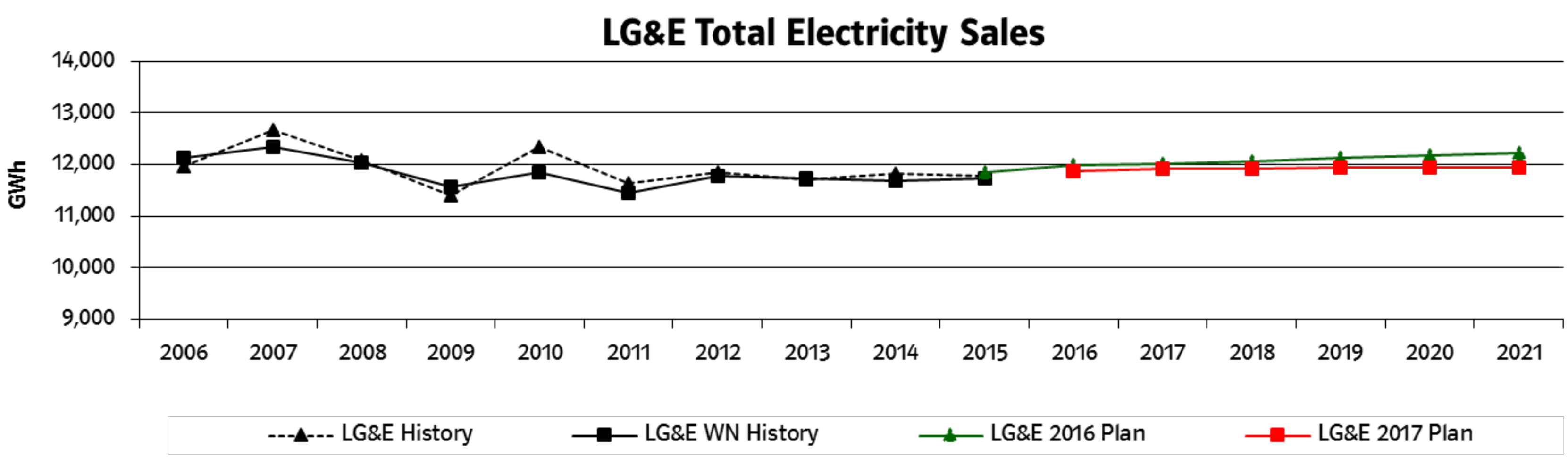
LG&E KU PPL companies

Sales forecasts decreased for both LG&E and KU





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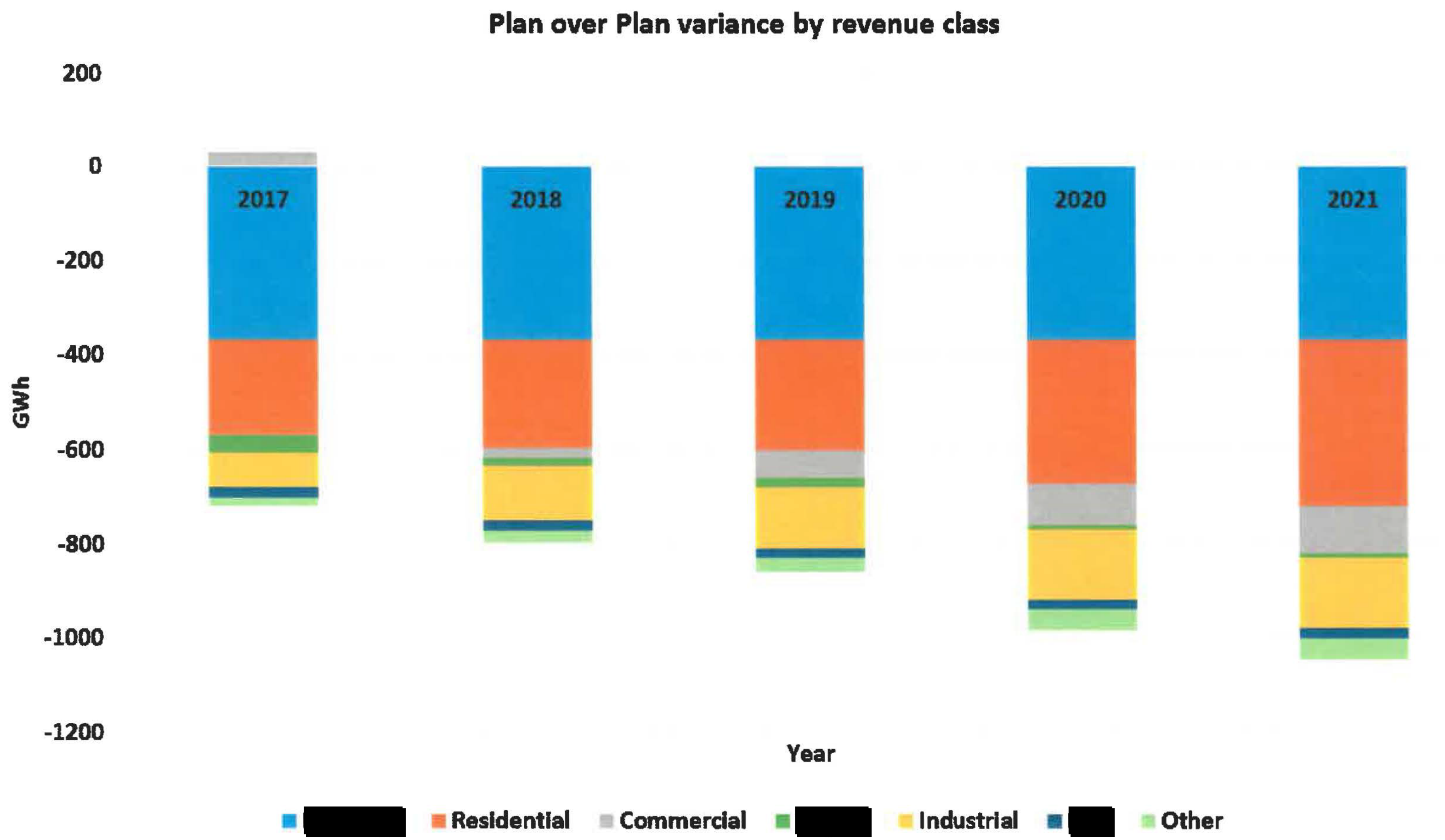
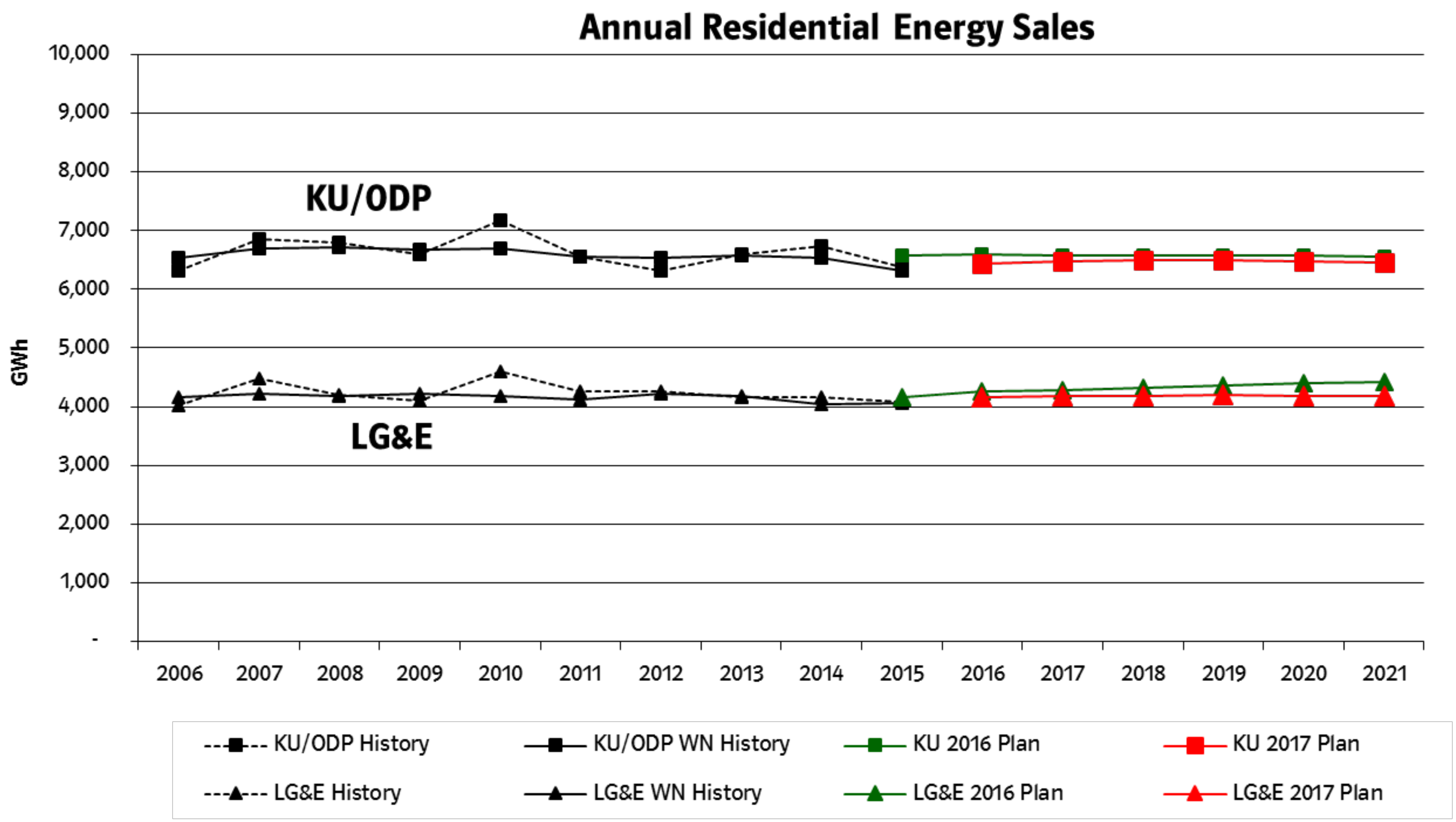
PPL companies

Loss of [redacted] and reductions to Residential and Industrial forecasts drive forecast variances



Residential Sales remain flat as increased efficiency offsets customer growth



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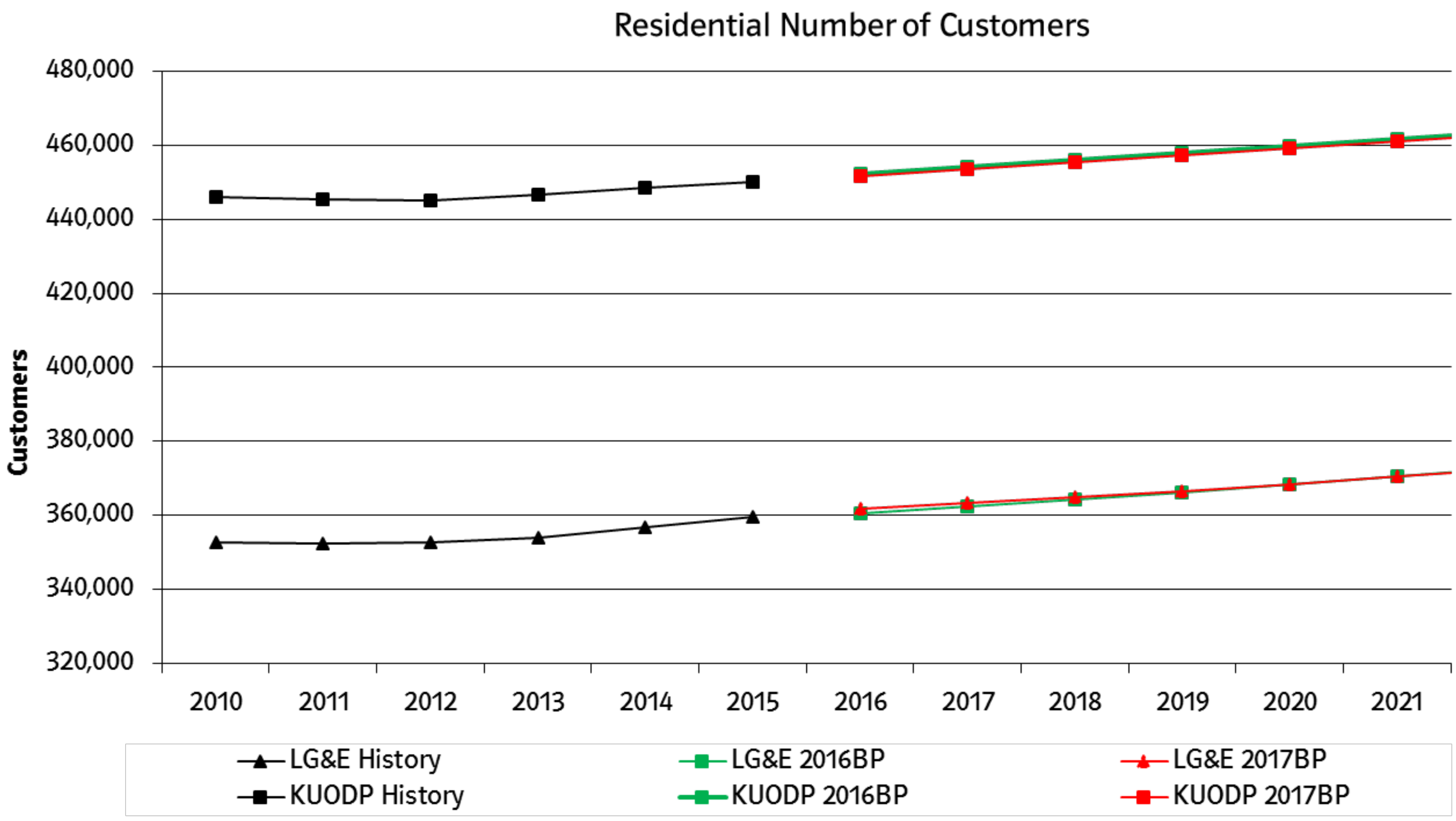
PPL companies

0.4% Annual Residential Customer Growth



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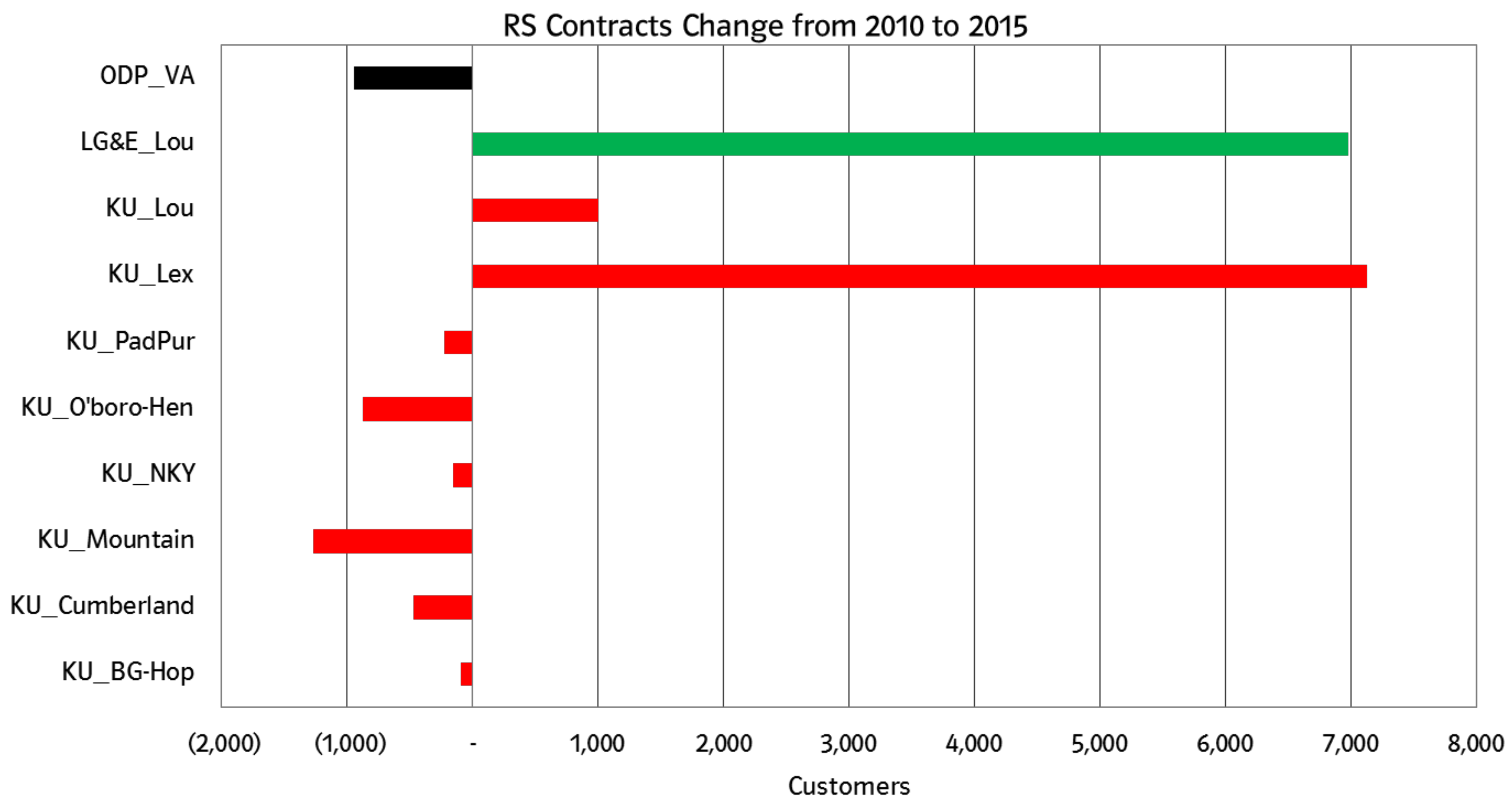
Residential customer growth tempered by reductions in rural regions



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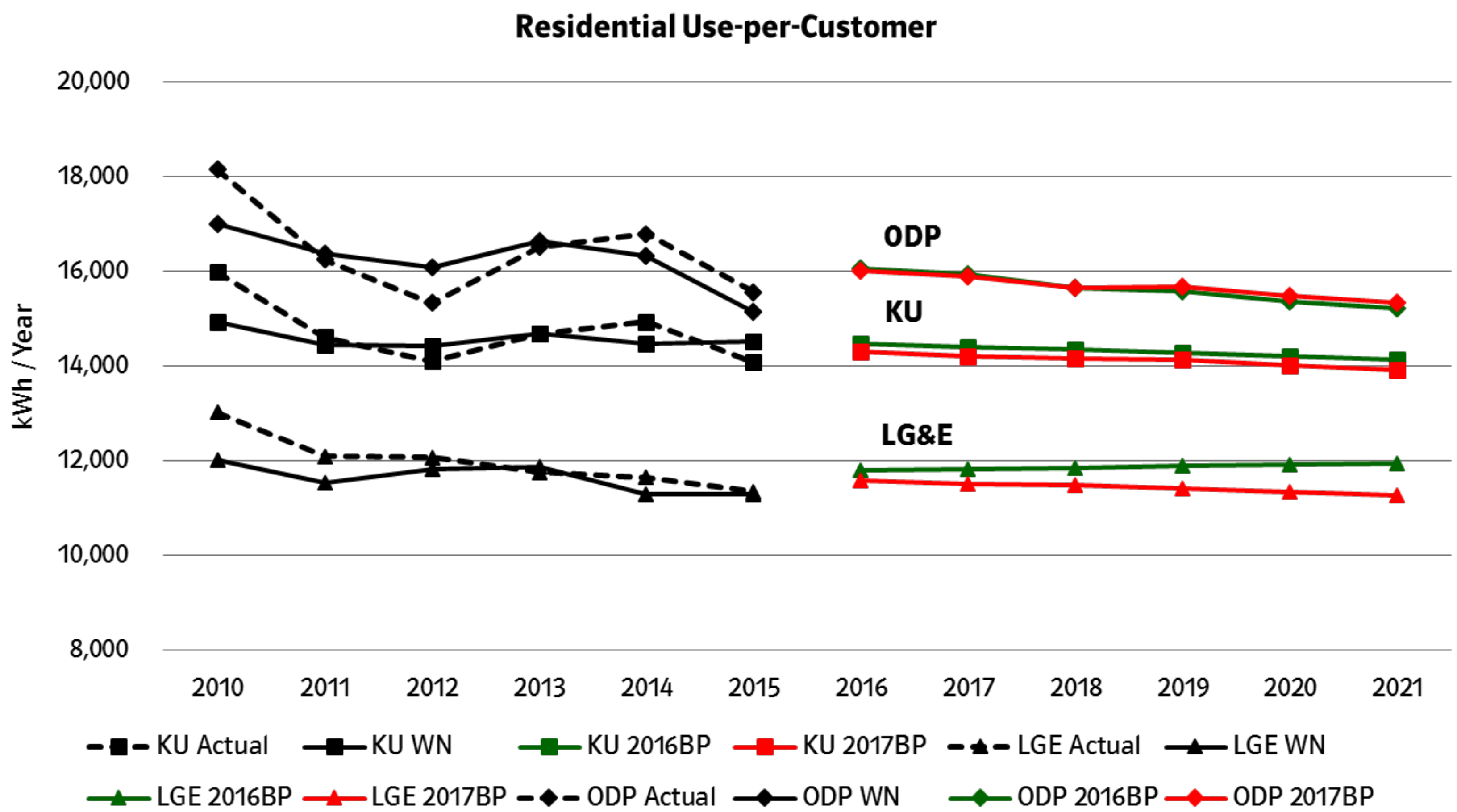
LG&E KU
PPL companies

Consistent with history, residential usage per customer declining in all service territories



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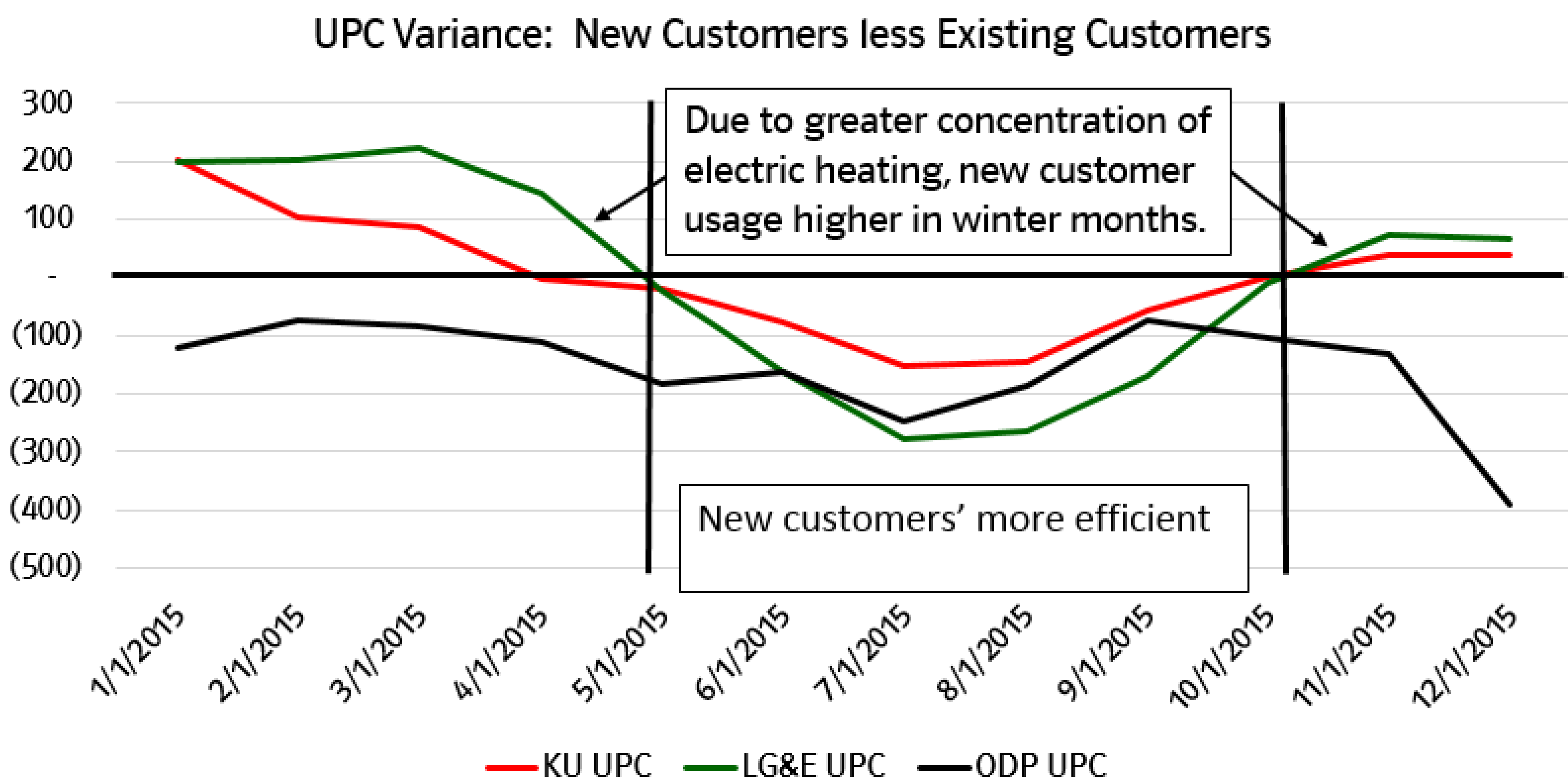
Electric heating offsetting efficiency impacts at LG&E



	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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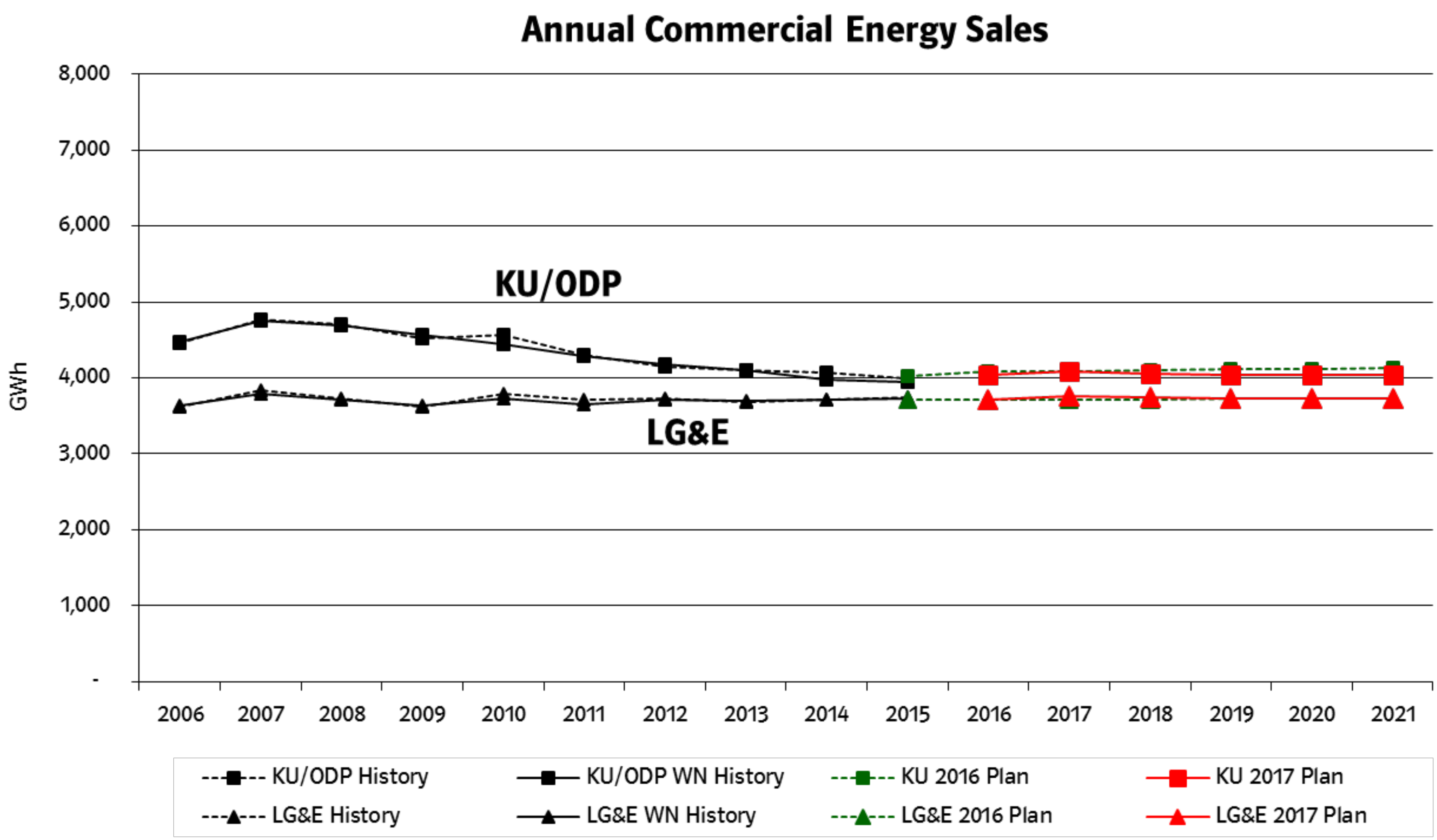
PPL companies

KU Commercial remains flat after post-recessionary decline



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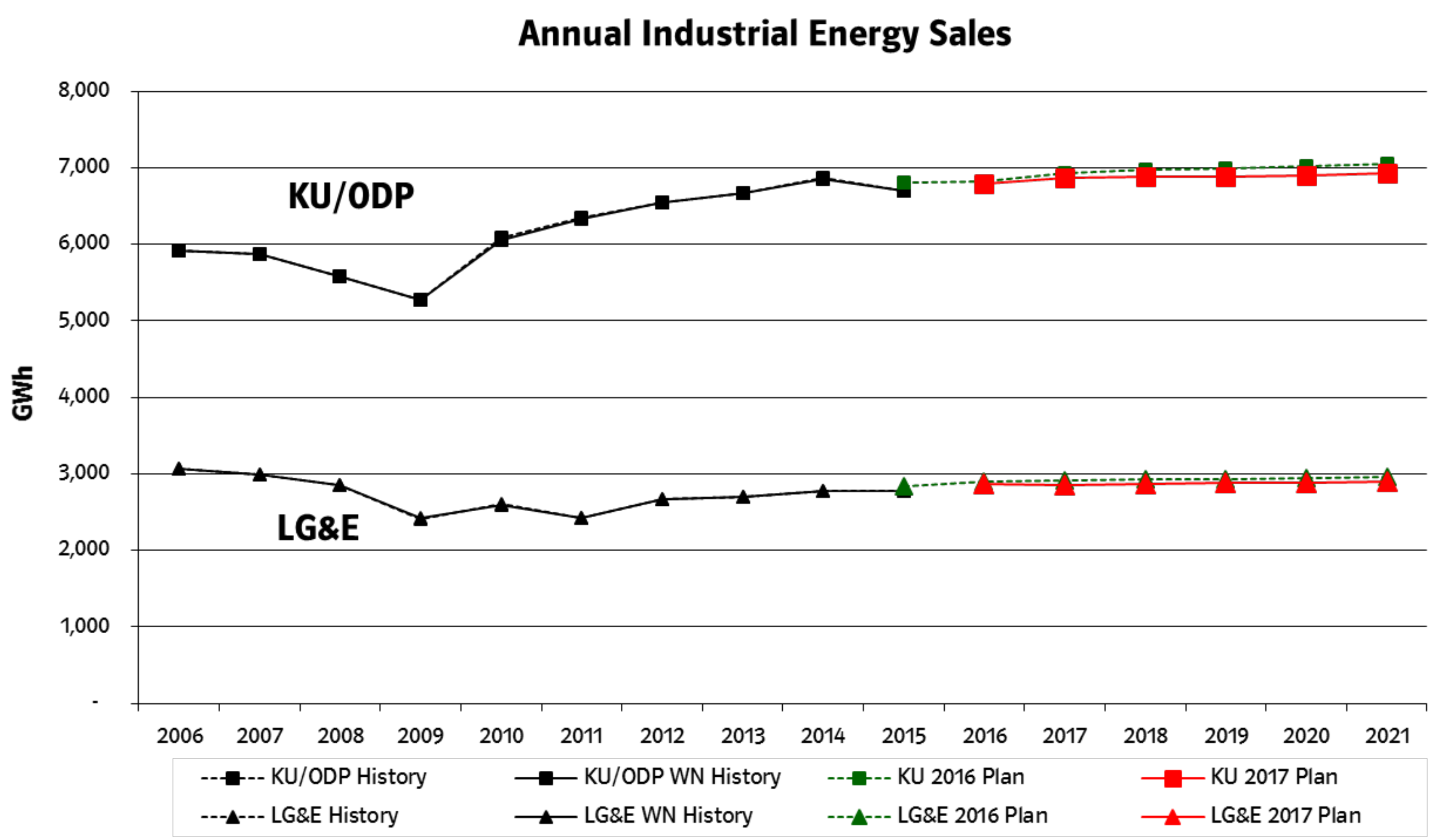
PPL companies

Major accounts drive short-term Industrial growth



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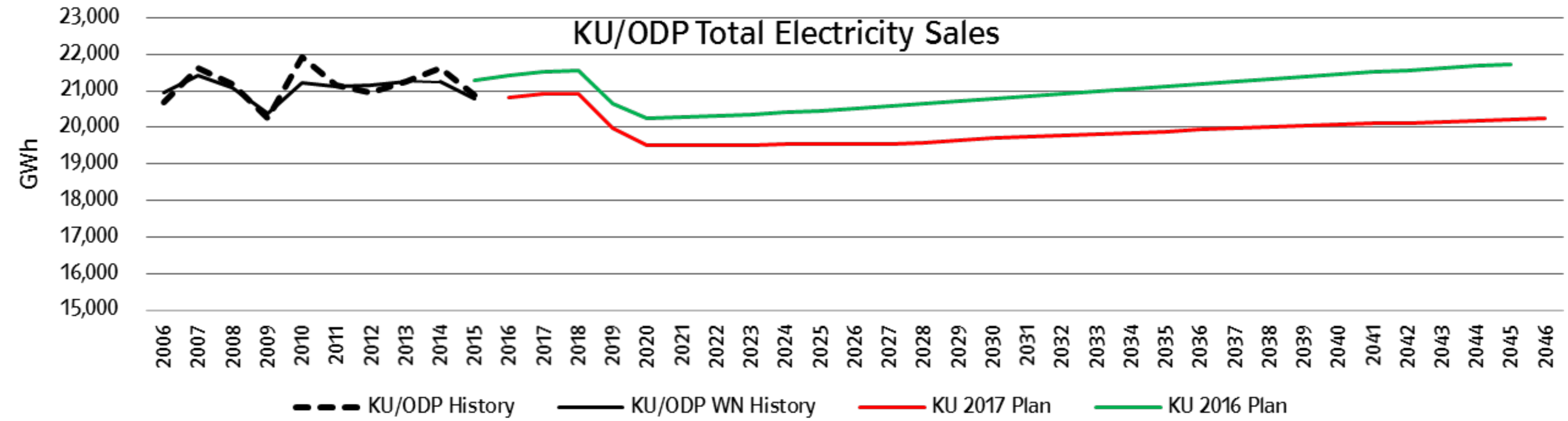
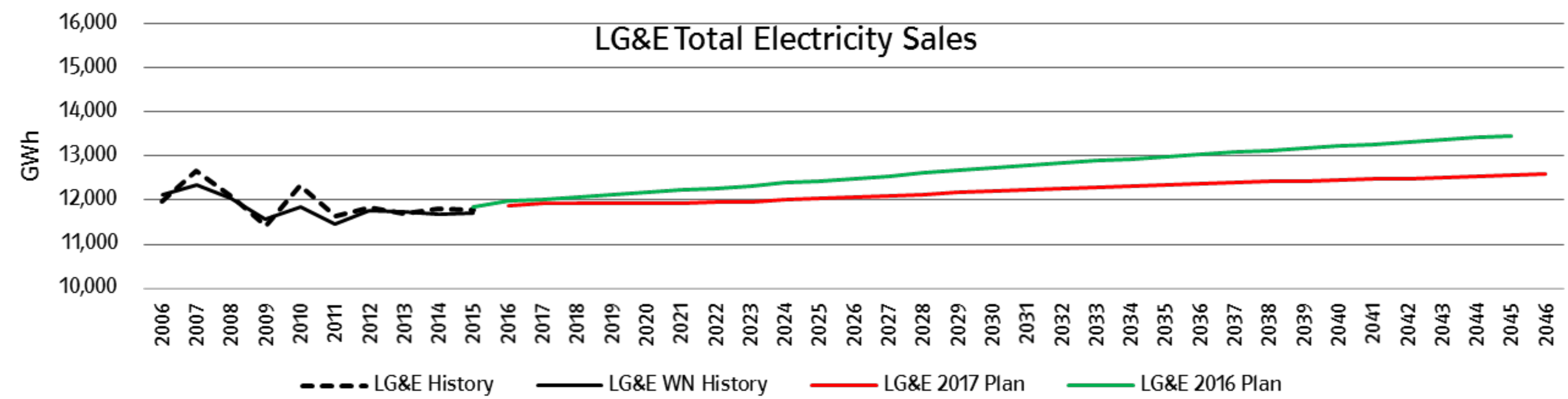
Consistent with national forecasts, 2017 Plan long-term growth rate is lower than 2016 Plan





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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*

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

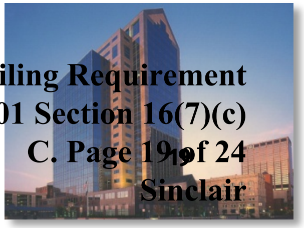
PPL companies

Appendix

7/11/2016







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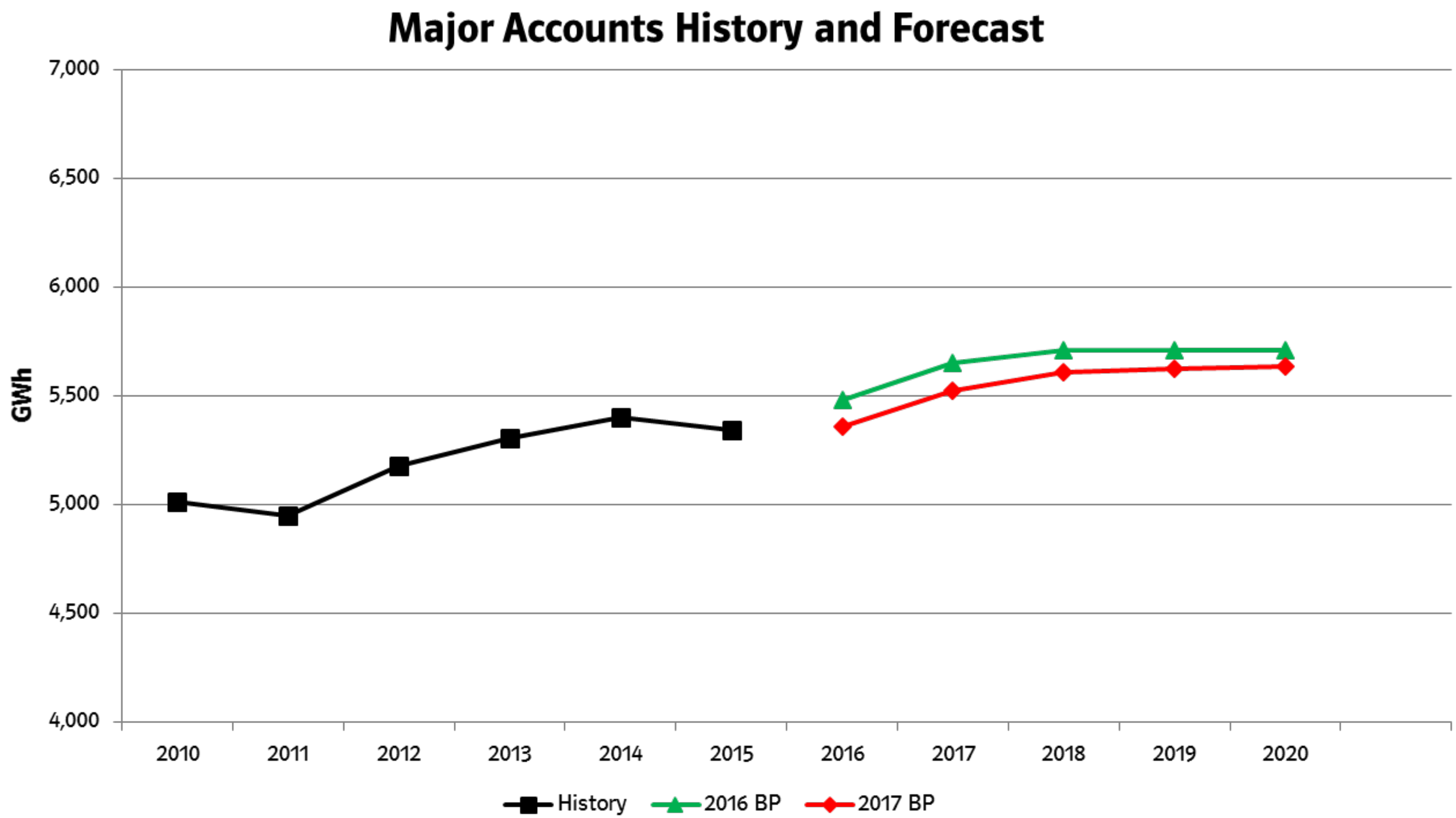
Major Accounts below 2016 Plan; growth through 2018 led by NAS and Toyota



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Plan over plan Major Account changes in 2017

CONFIDENTIAL INFORMATION REDACTED

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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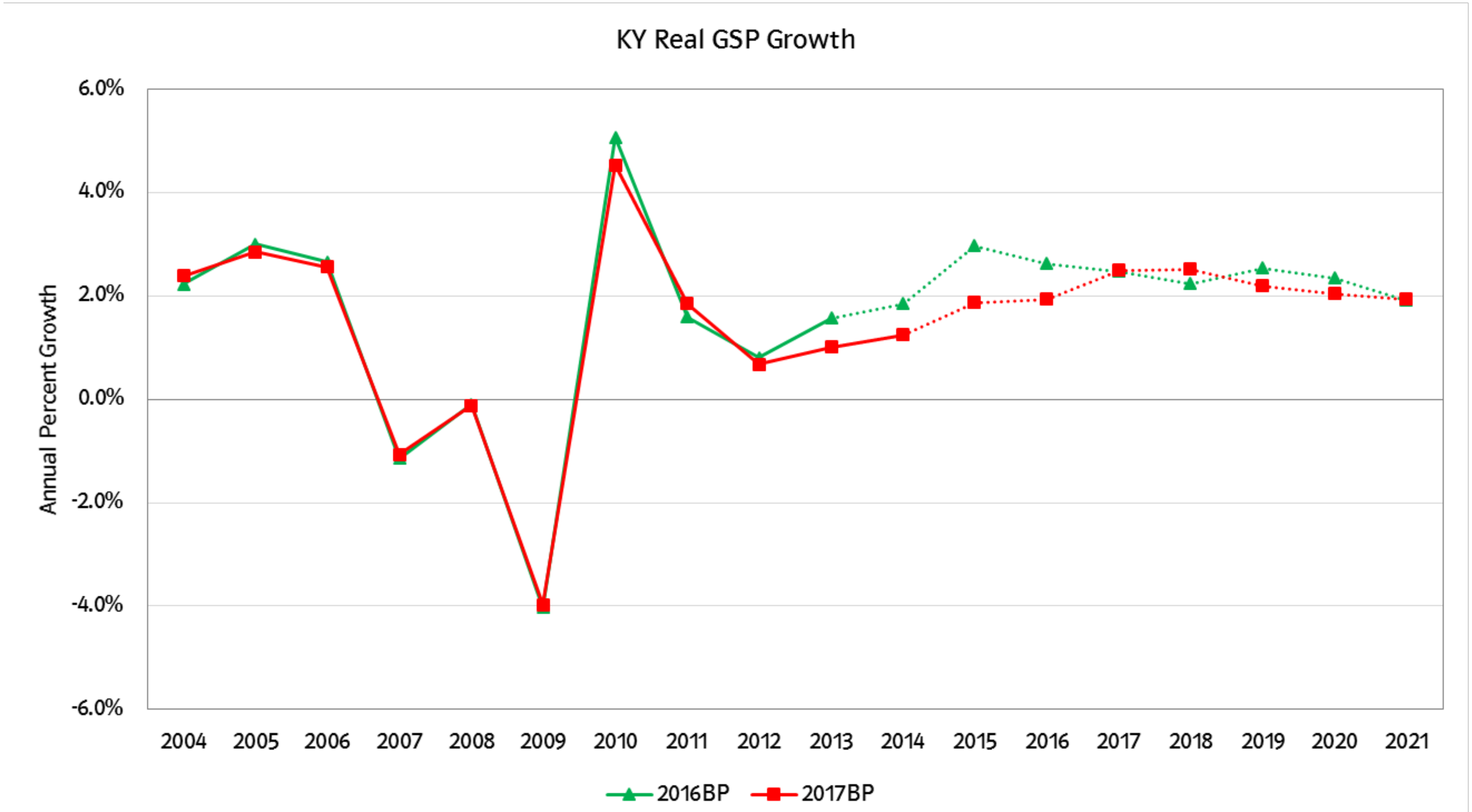
GSP recent history revised downwards



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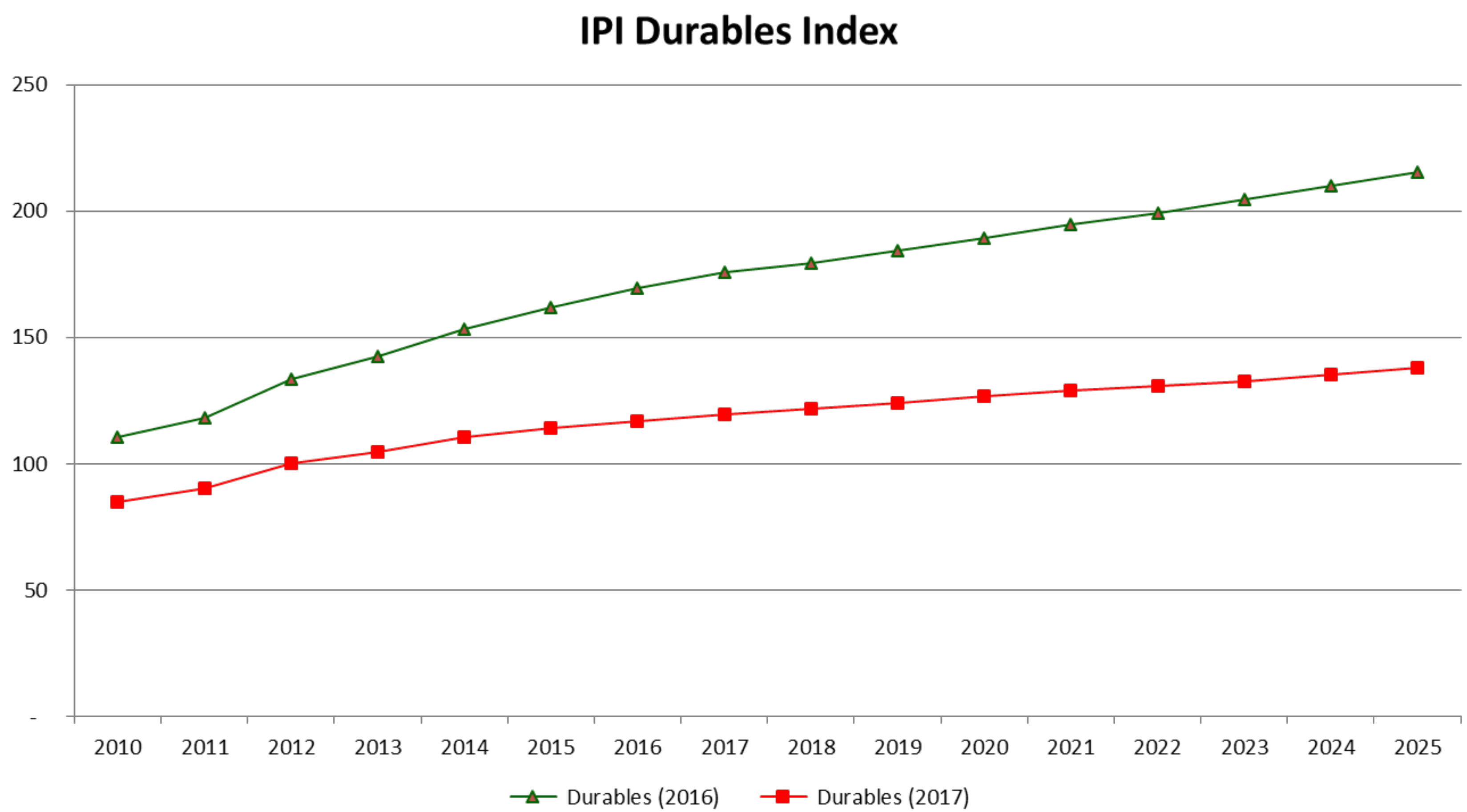
IPI Durables lower than 2016 Plan



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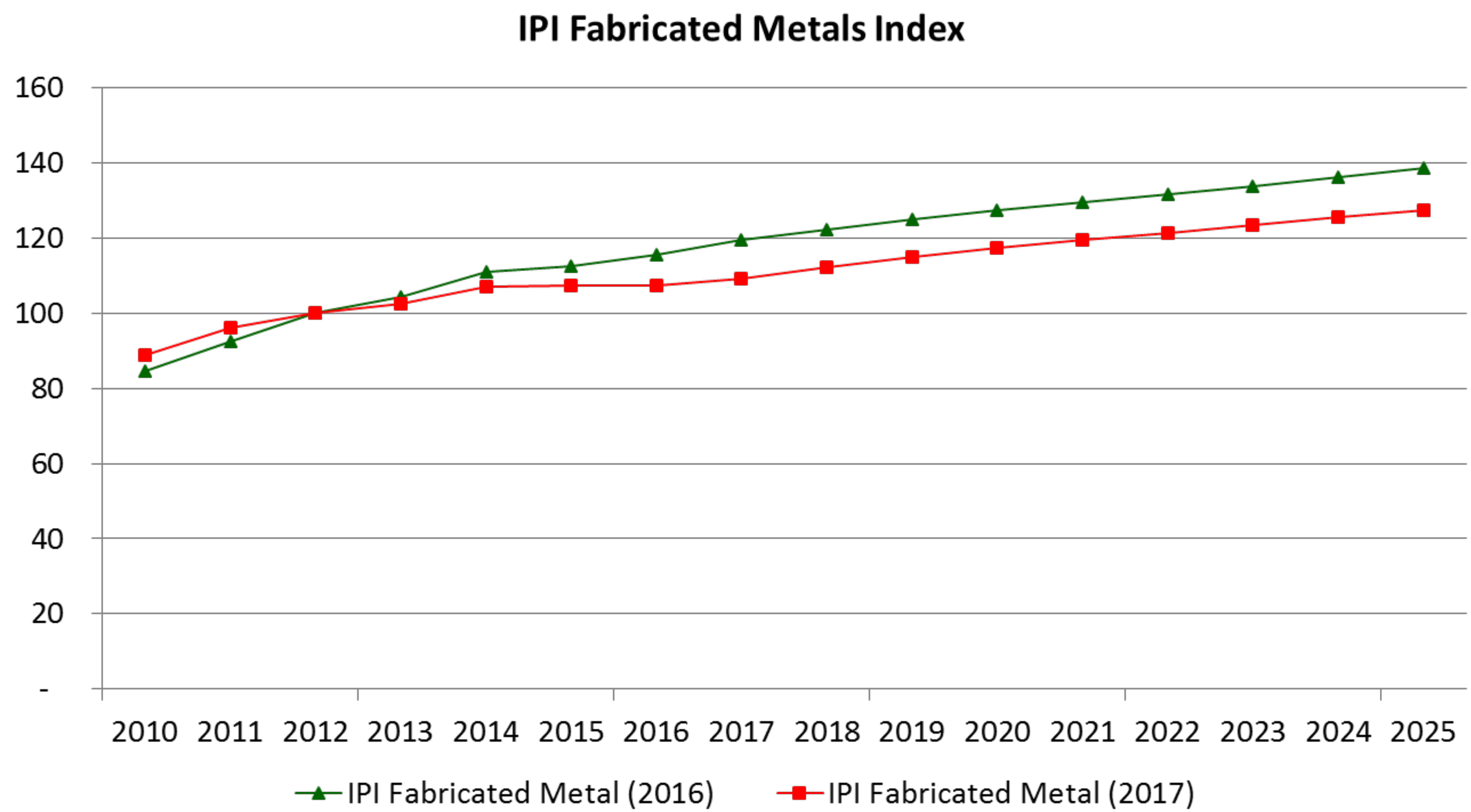
Fabricated Metals Index lowered in near term



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LG&E KU
PPL companies

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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

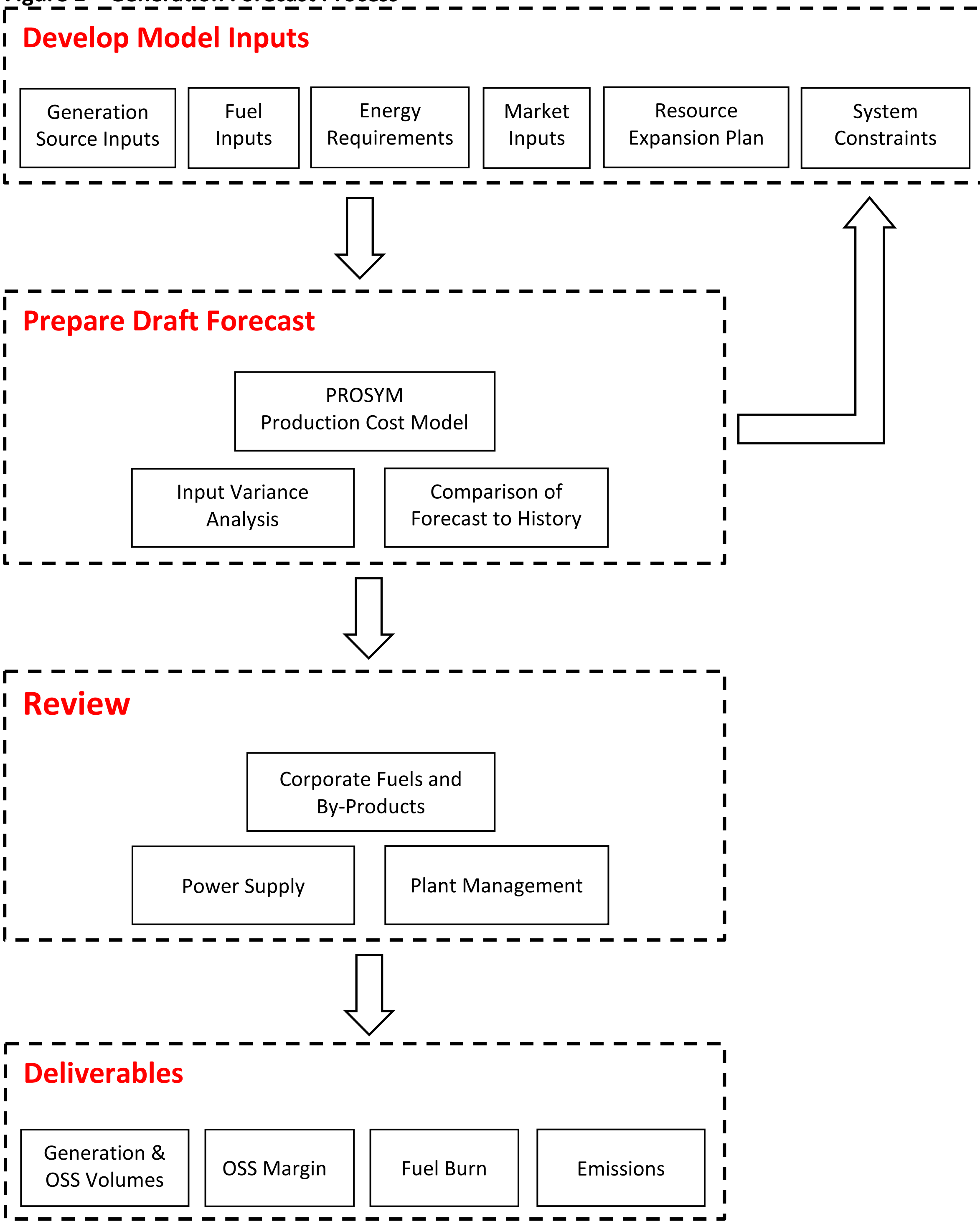
The Companies' generation forecast is developed using ABB's PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve requirements and other 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 5^{th} 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

PPL companies

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

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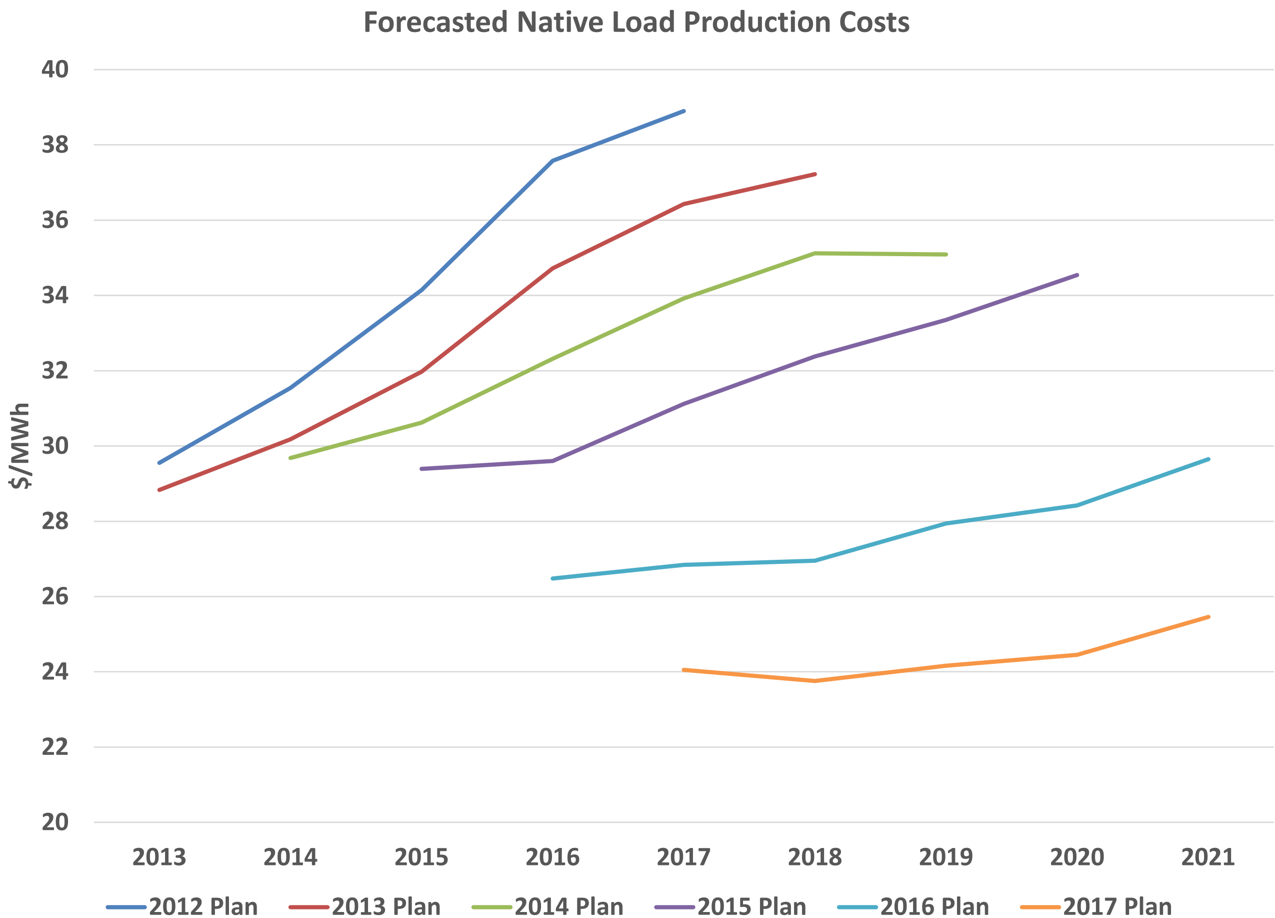
Forecasted native load production costs continue pattern of Plan over Plan declines



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LG&E KU
PPL companies

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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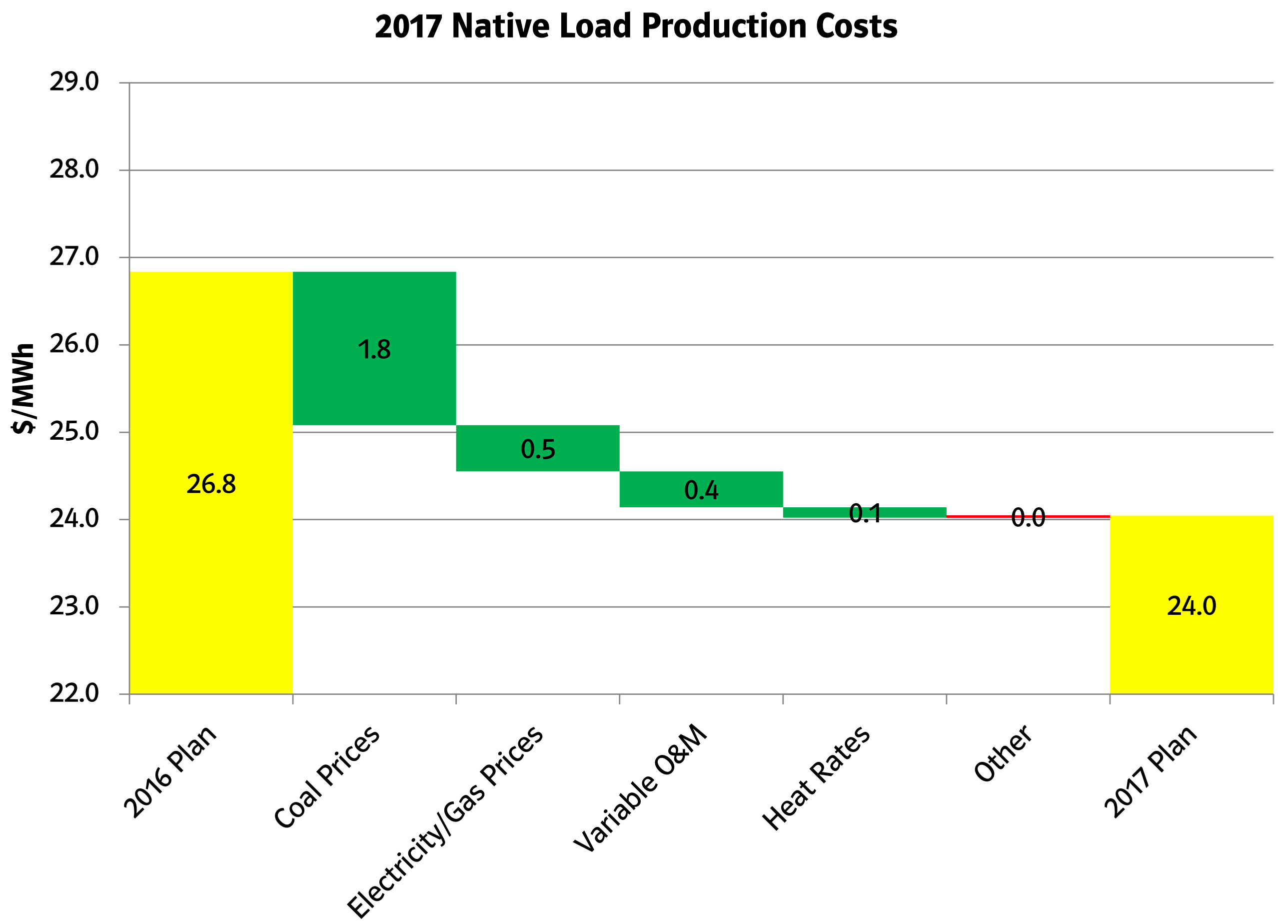
In 2017-2019, lower coal and gas prices are the key drivers of lower native load production costs



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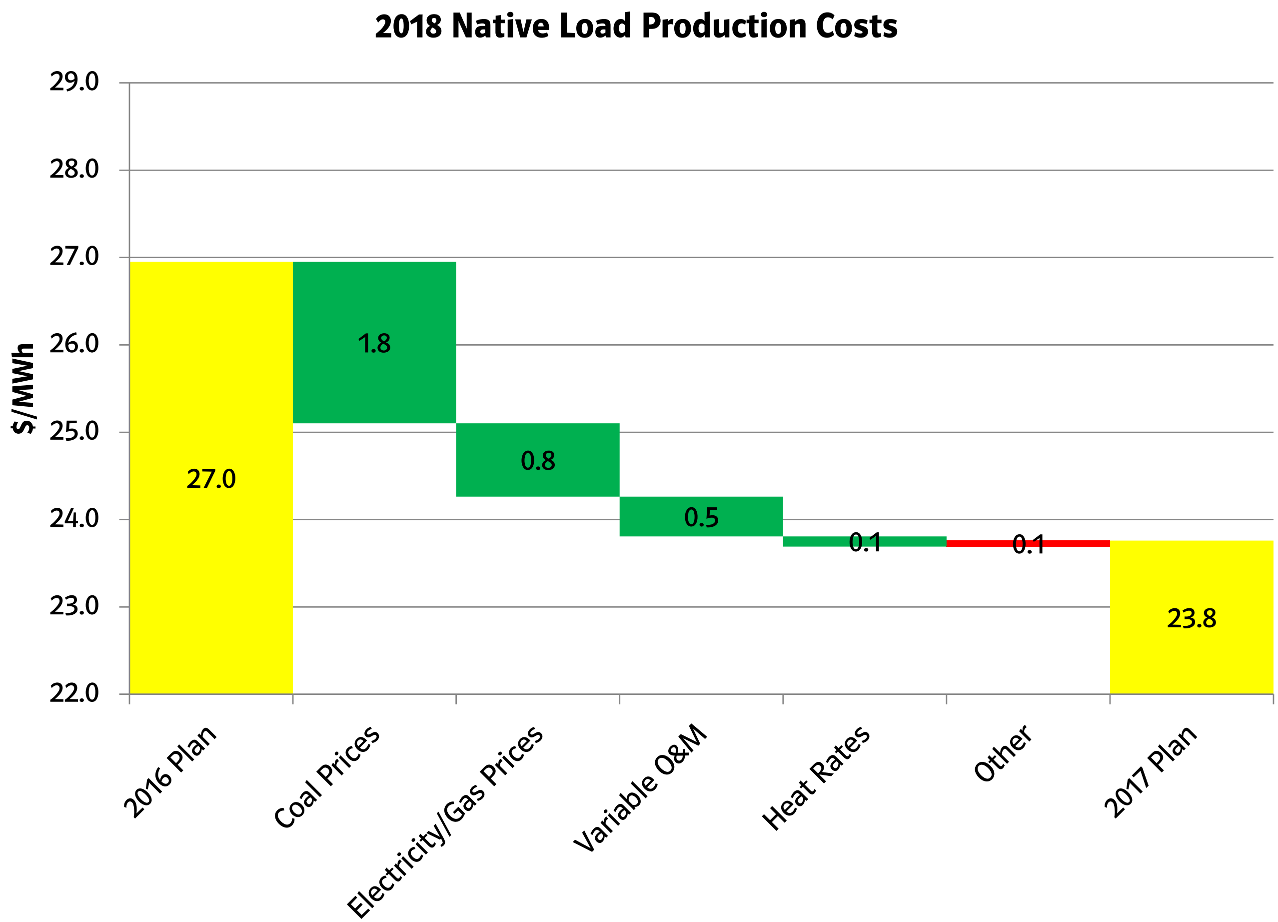
In 2017-2019, lower coal and gas prices are the key drivers of lower native load production costs



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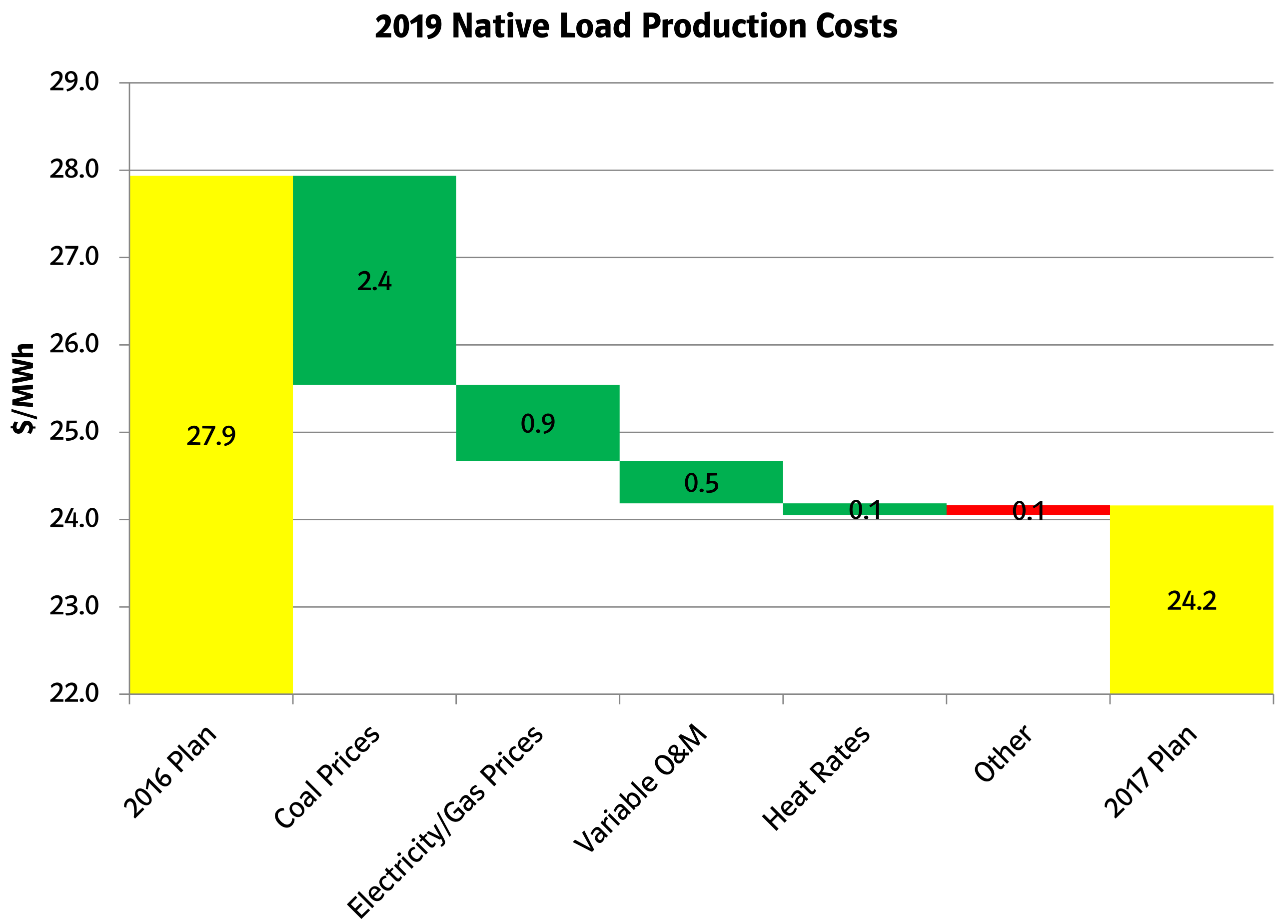
LG&E KU
PPL companies

In 2017-2019, lower coal and gas prices are the key drivers of lower native load production costs



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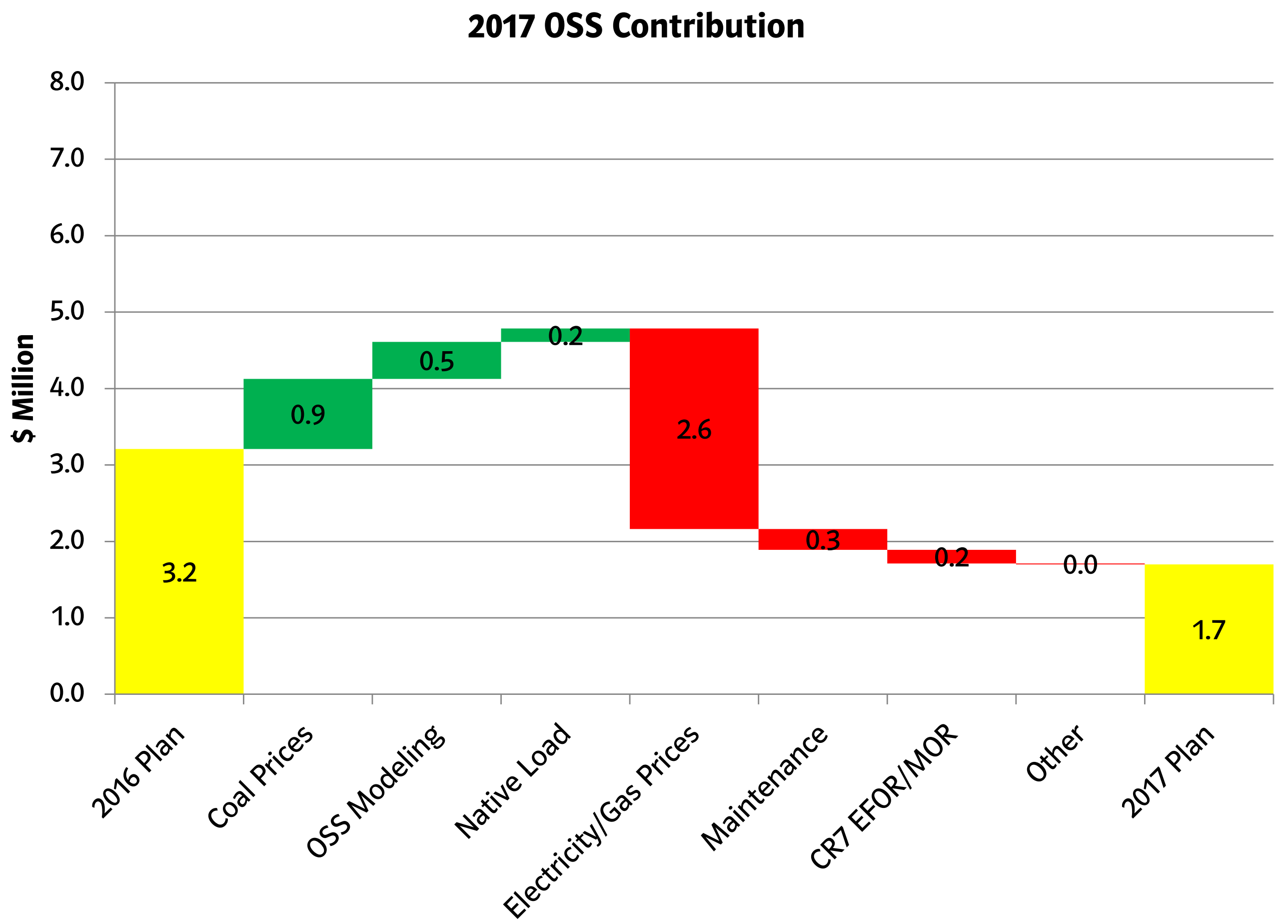
PPL companies

In 2017-2018, lower market electricity prices drive lower OSS contribution



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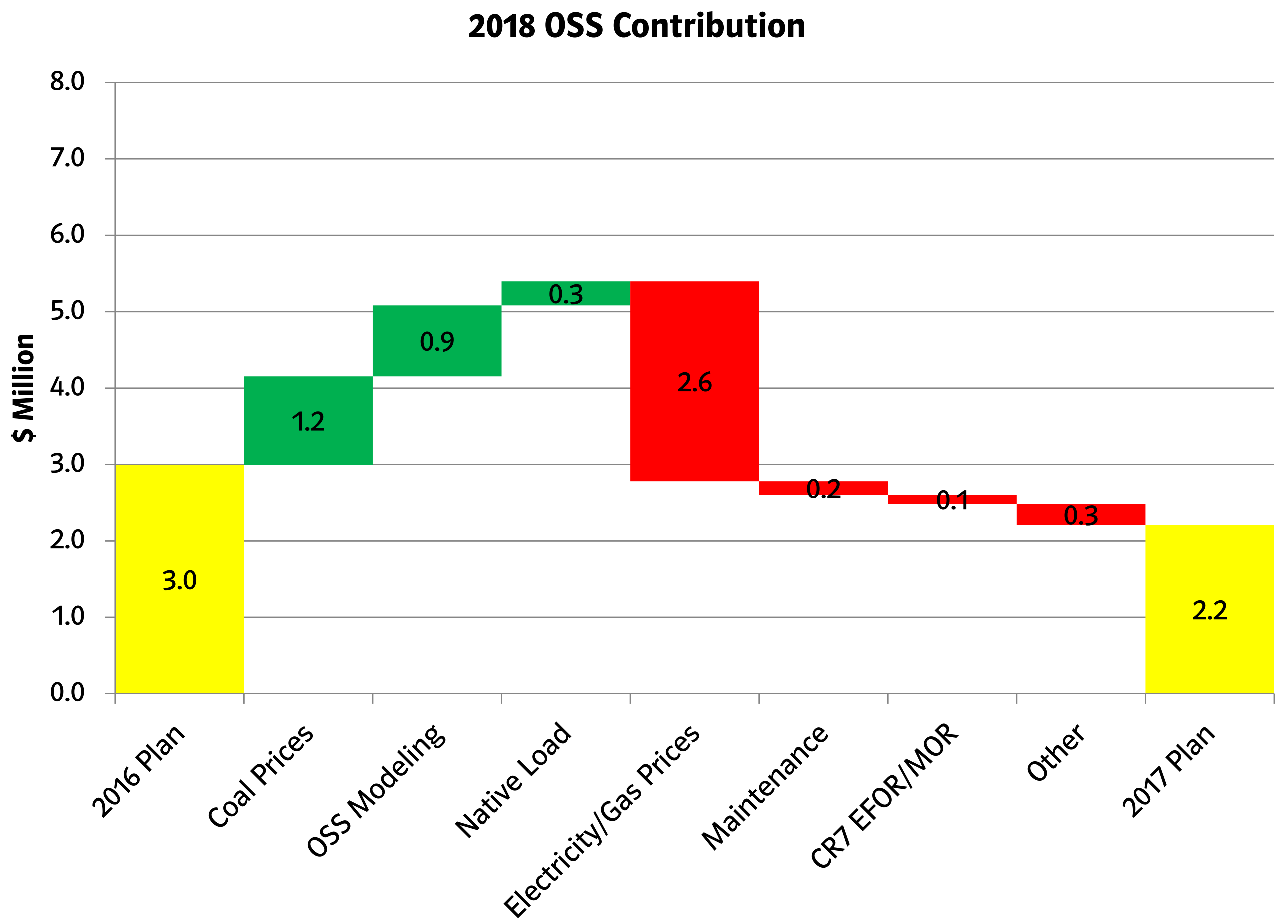
LG&E KU PPL companies

In 2017-2018, lower market electricity prices drive lower OSS contribution



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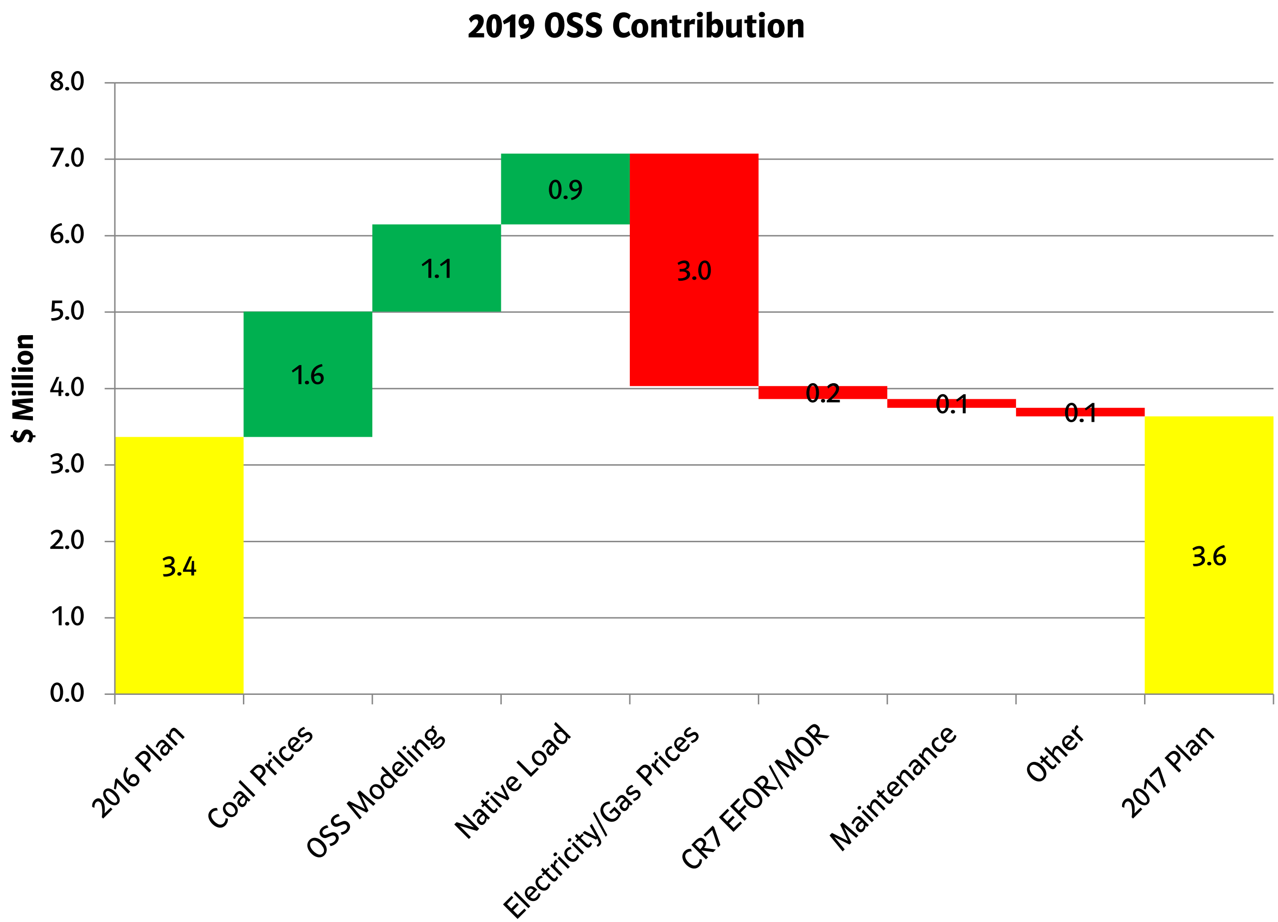
In 2019, lower market electricity prices offset lower coal prices, lower load, and OSS modeling changes, resulting in a small increase to OSS contribution



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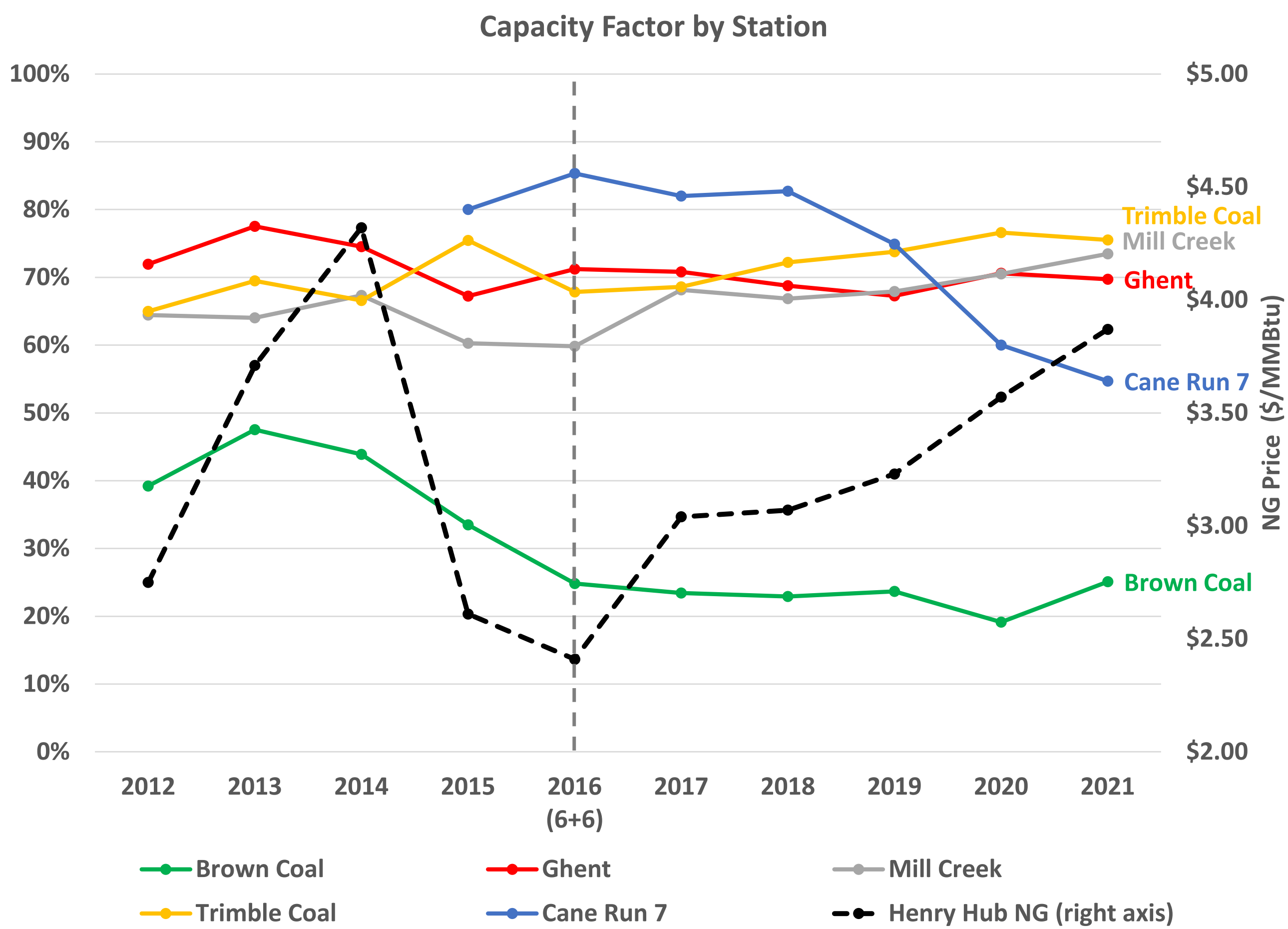
As gas prices increase, generation shifts from CR7 to Ghent, Mill Creek, and Trimble County



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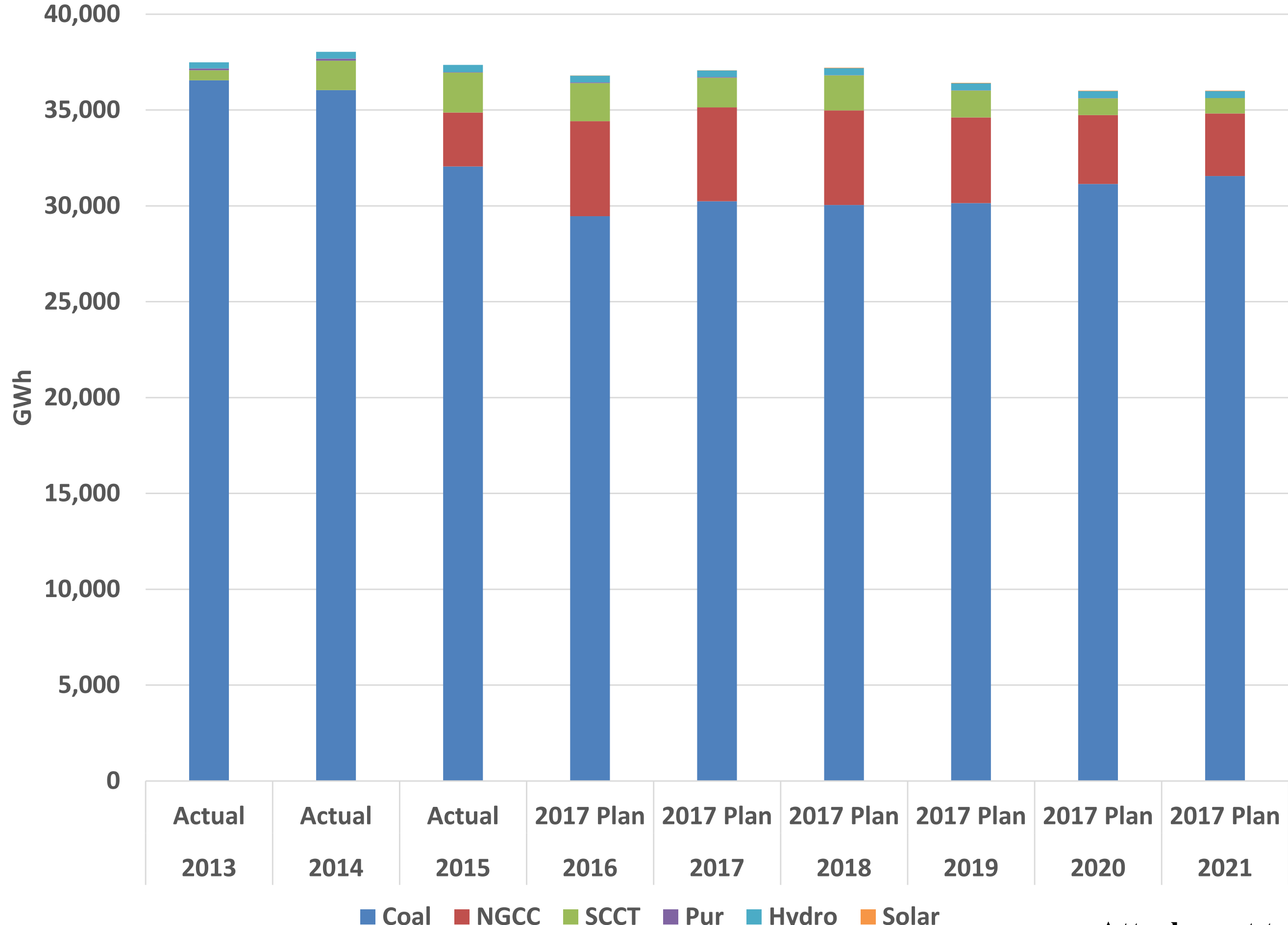
LG&E KU PPL companies

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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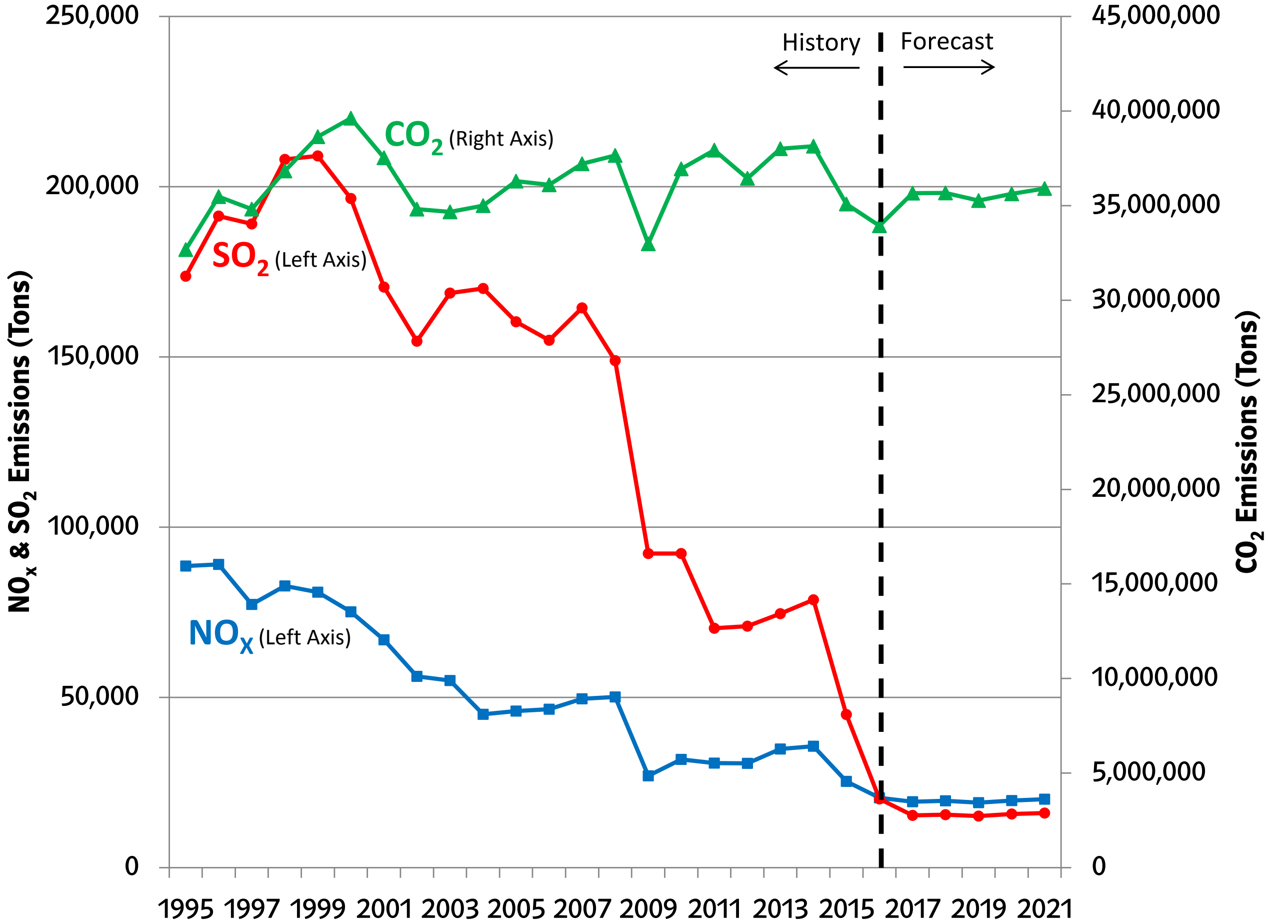
Emissions have decreased with addition of controls



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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

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\$)

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*

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LG&E KU 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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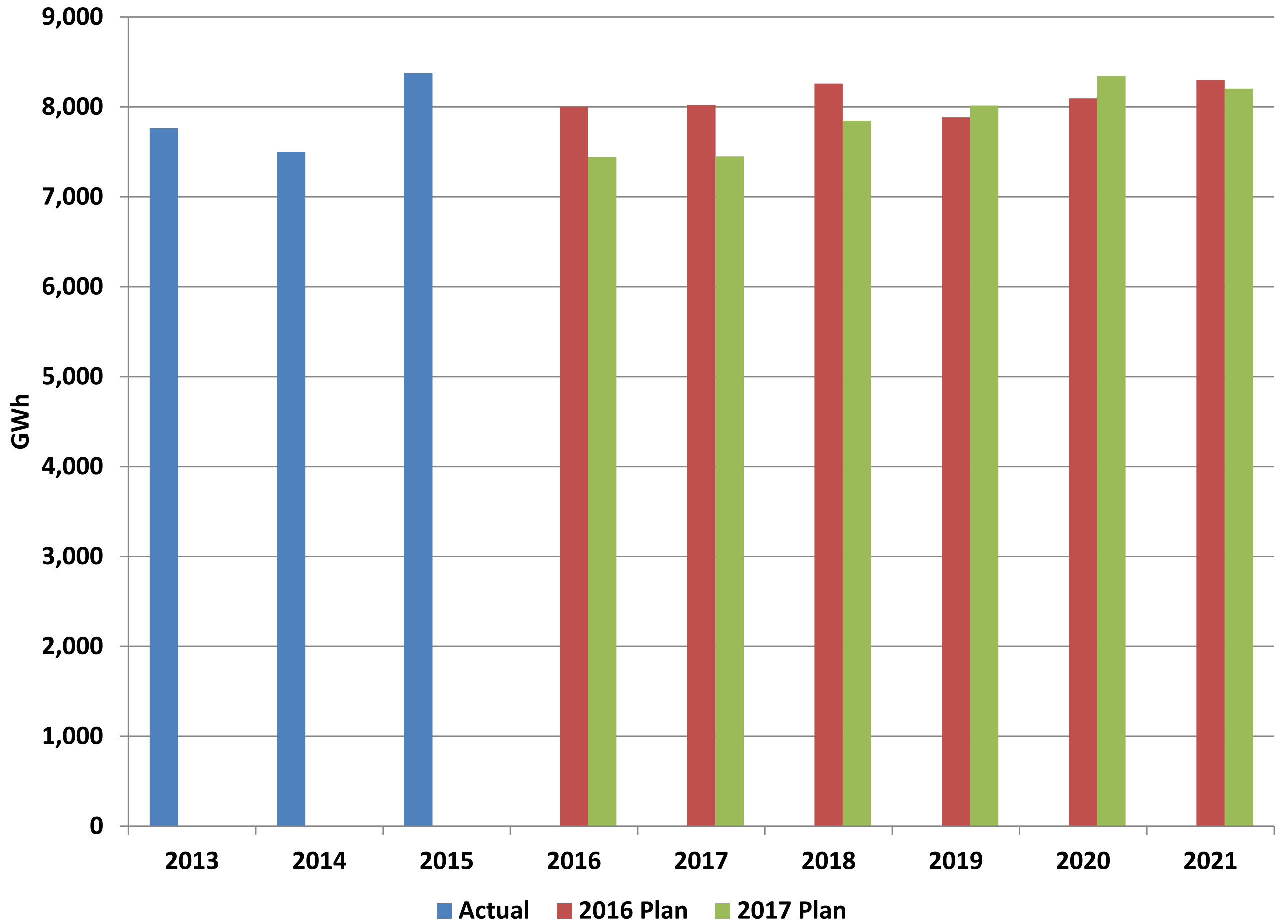
PPL companies

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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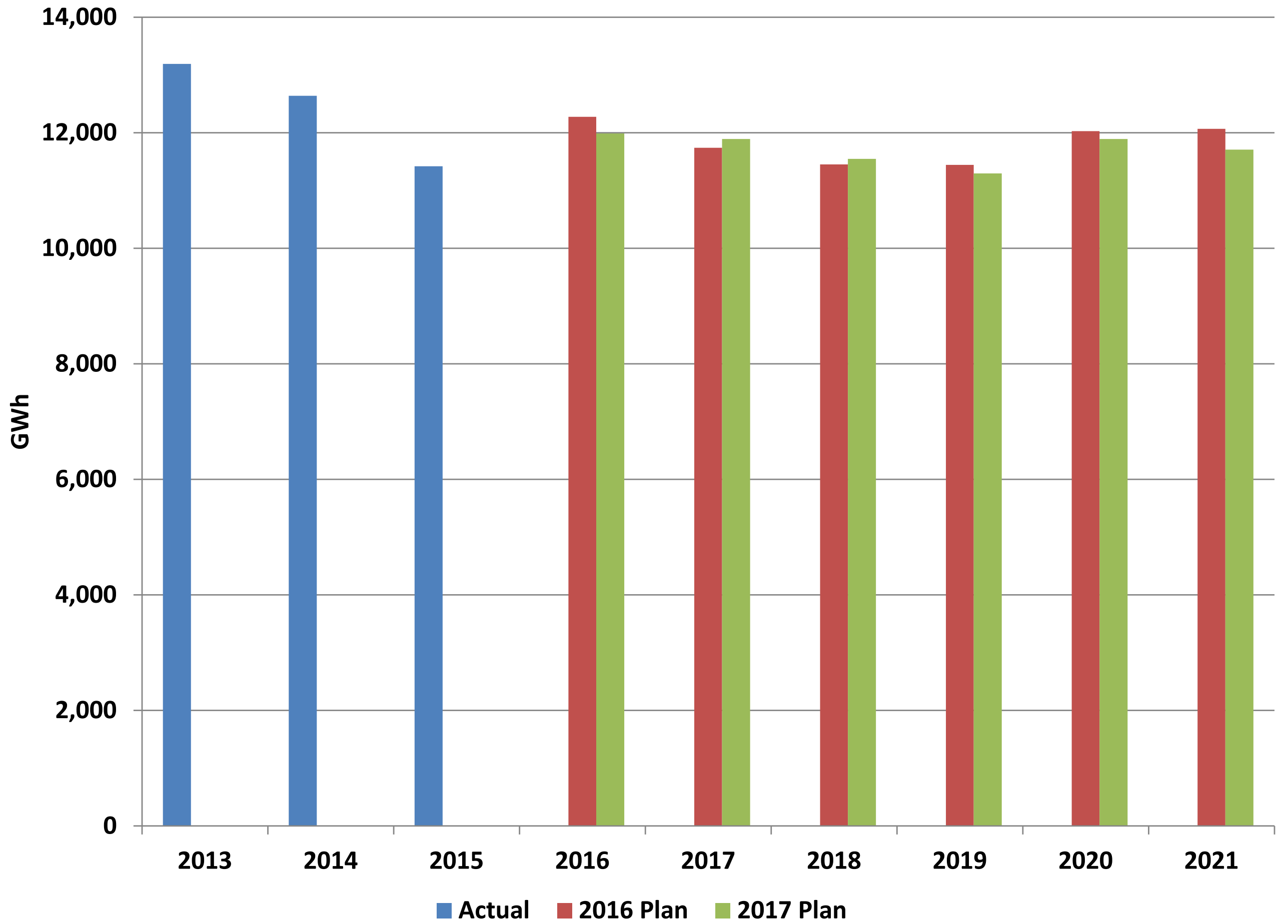
Ghent generation is largely unchanged due to offsetting impacts of coal and gas price decreases



2017 Plan in 2016: 6 + 6

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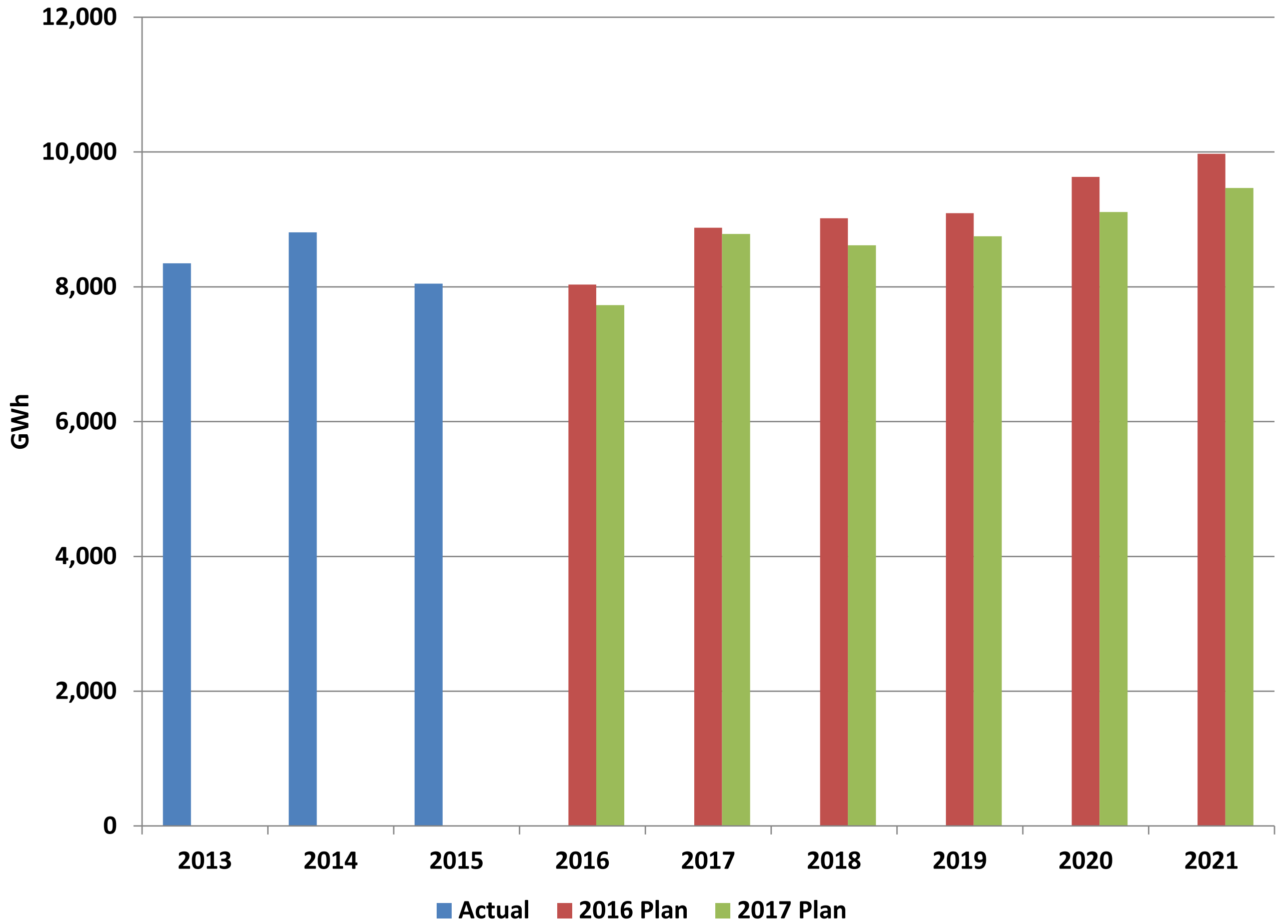
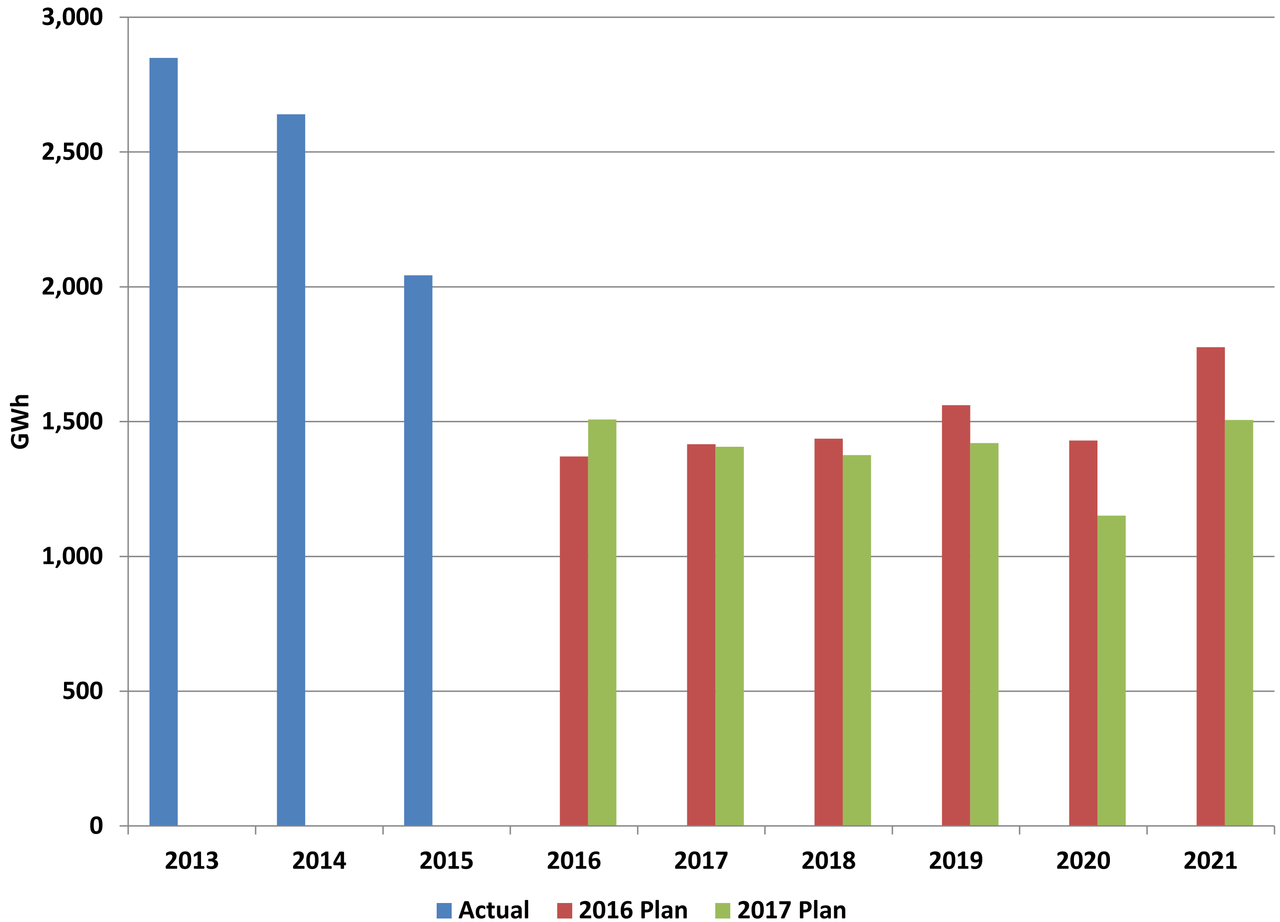
Mill Creek generation decreases due to lower coal/gas price spreads and load



2017 Plan in 2016: 6 + 6

PPL companies

Brown coal generation decreases in 2018-2021 due to lower gas prices and load



2017 Plan in 2016: 6 + 6

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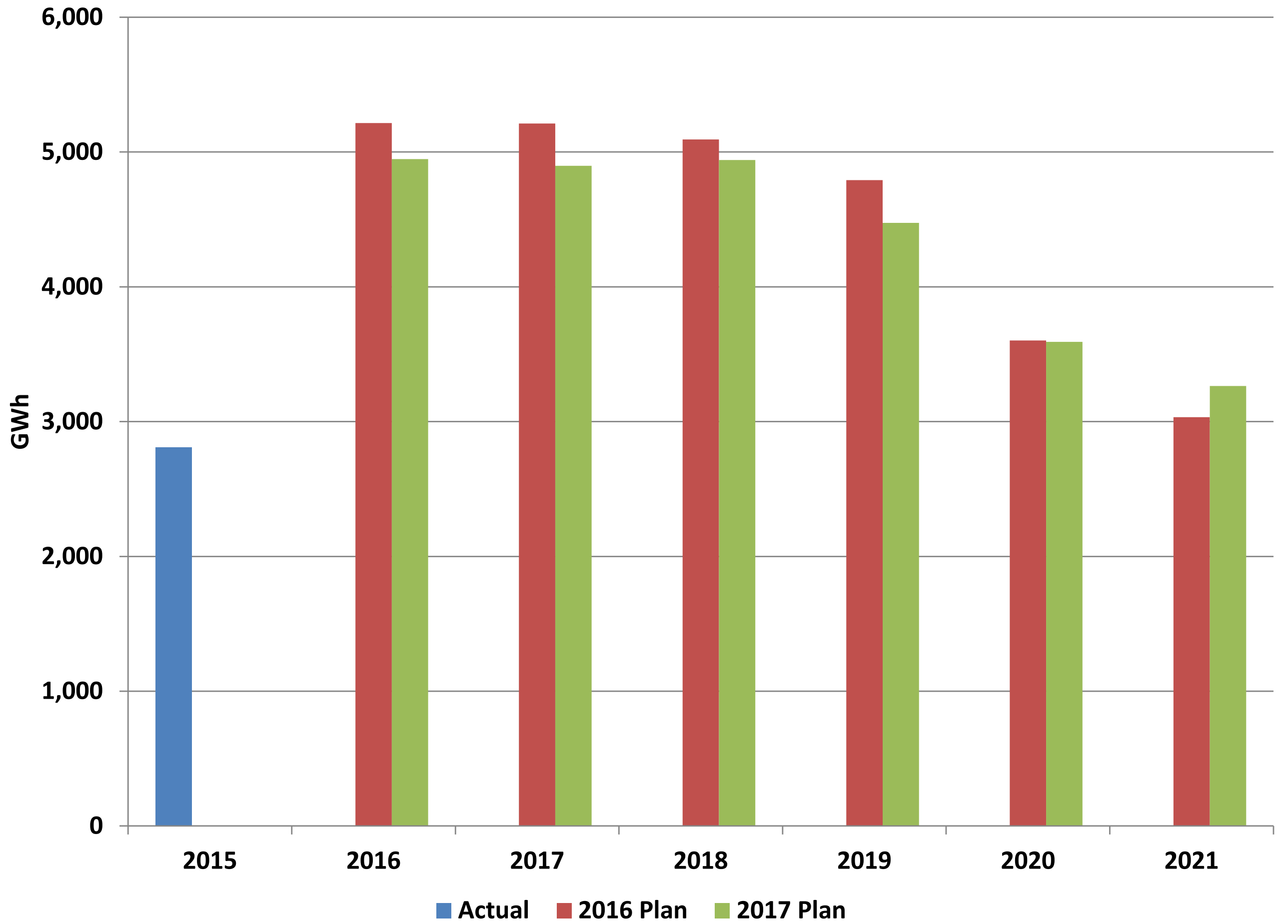
Cane Run 7 generation decreased slightly due to maintenance outage modeling and load, but increased in later years due to lower gas prices



2017 Plan in 2016: 6 + 6
CR7 commissioned in June 2015

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PPL companies

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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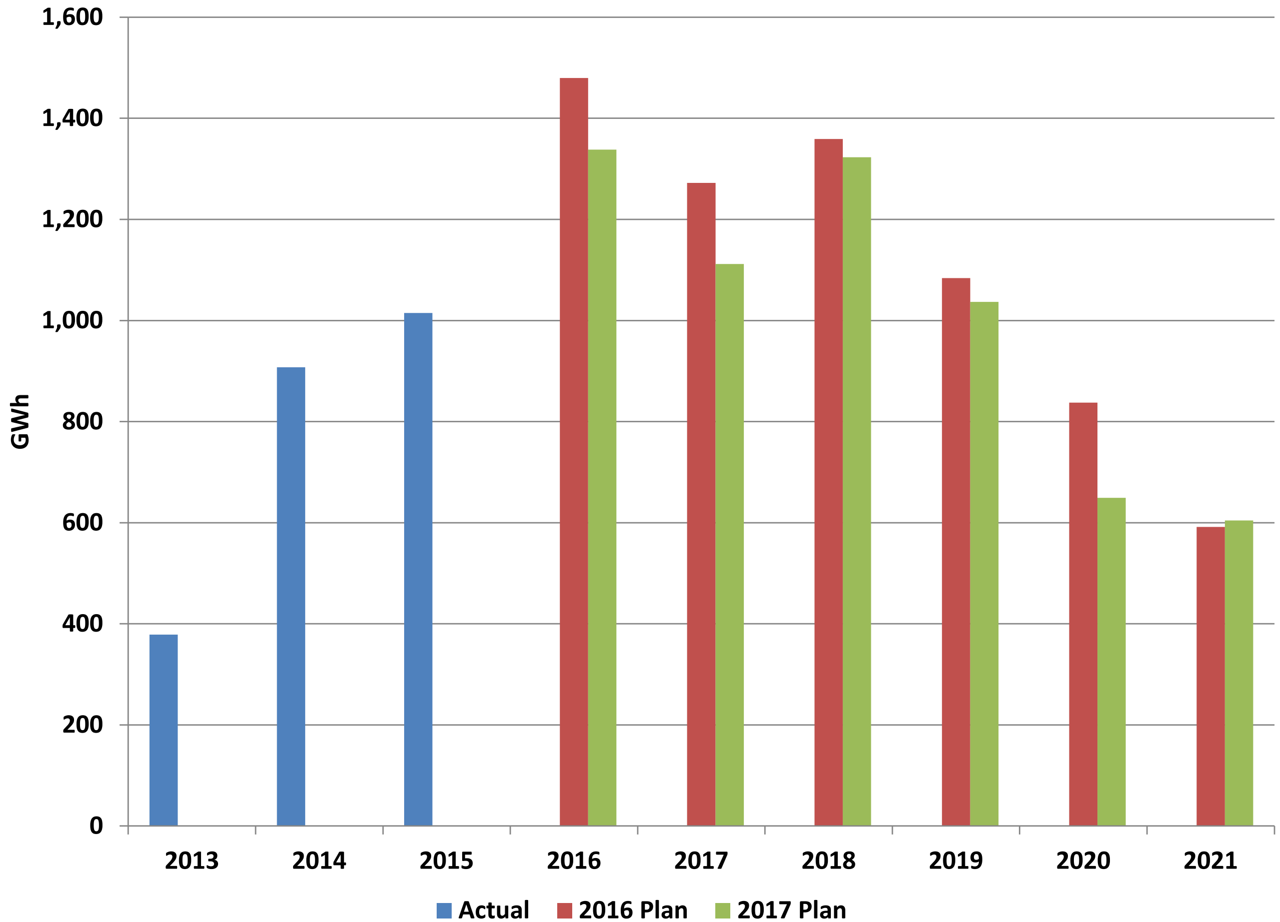
Trimble CT generation decreases mostly due to lower load and lower coal prices



2017 Plan in 2016: 6 + 6

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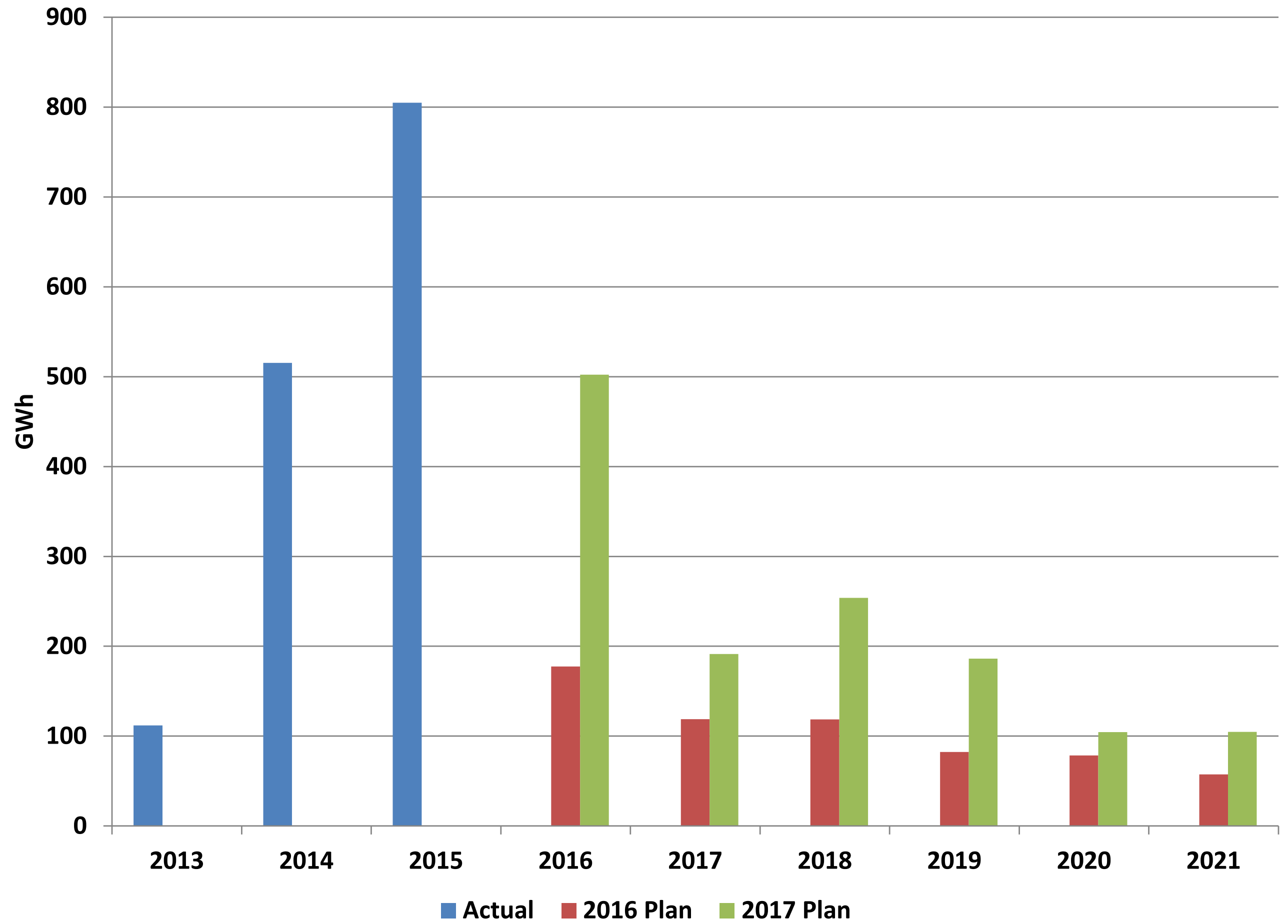
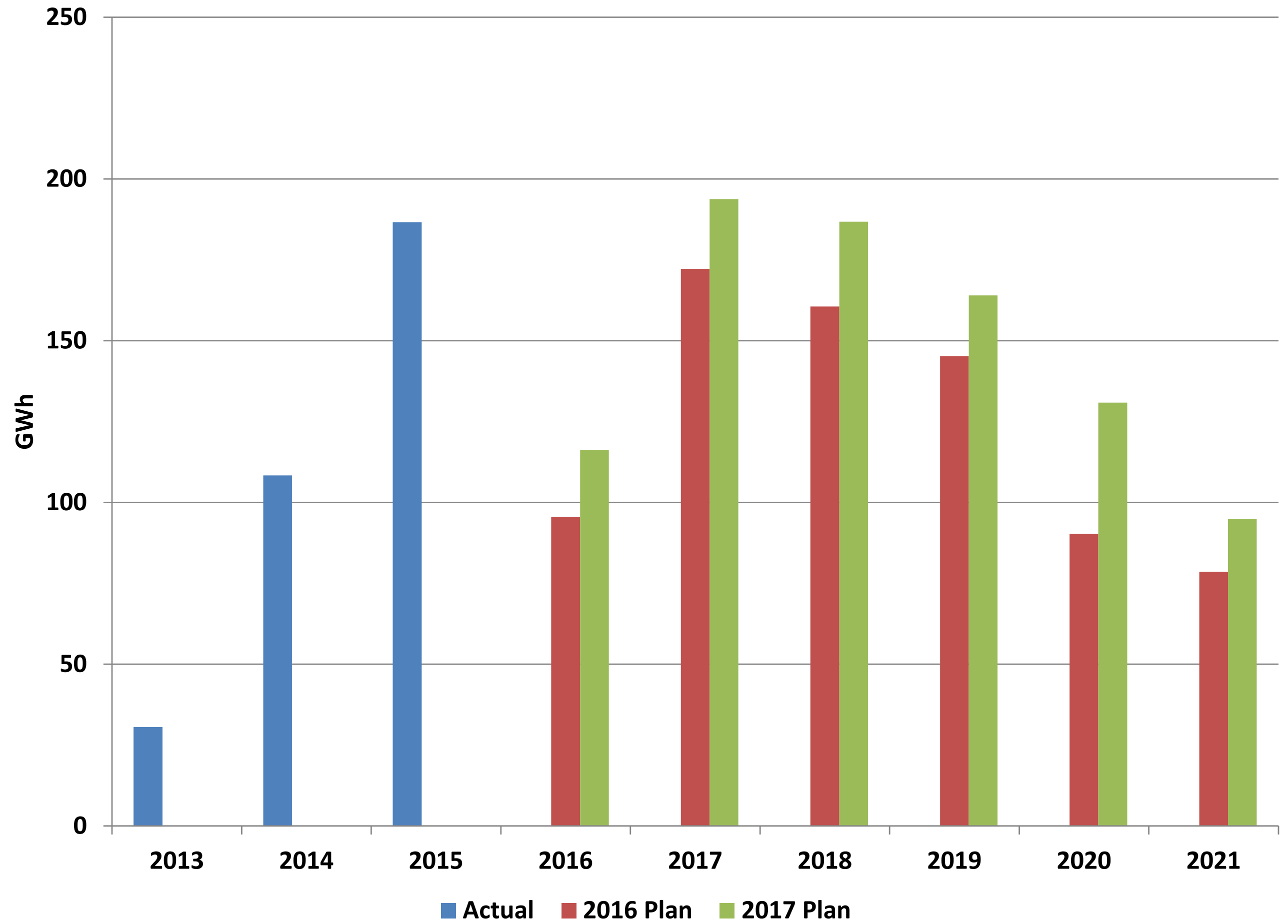
Brown CT generation increases mostly due to relative changes in CT maintenance costs



2017 Plan in 2016: 6 + 6

PPL companies

Paddy's Run generation increases mostly due to lower gas prices



2017 Plan in 2016: 6 + 6

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LG&E KU
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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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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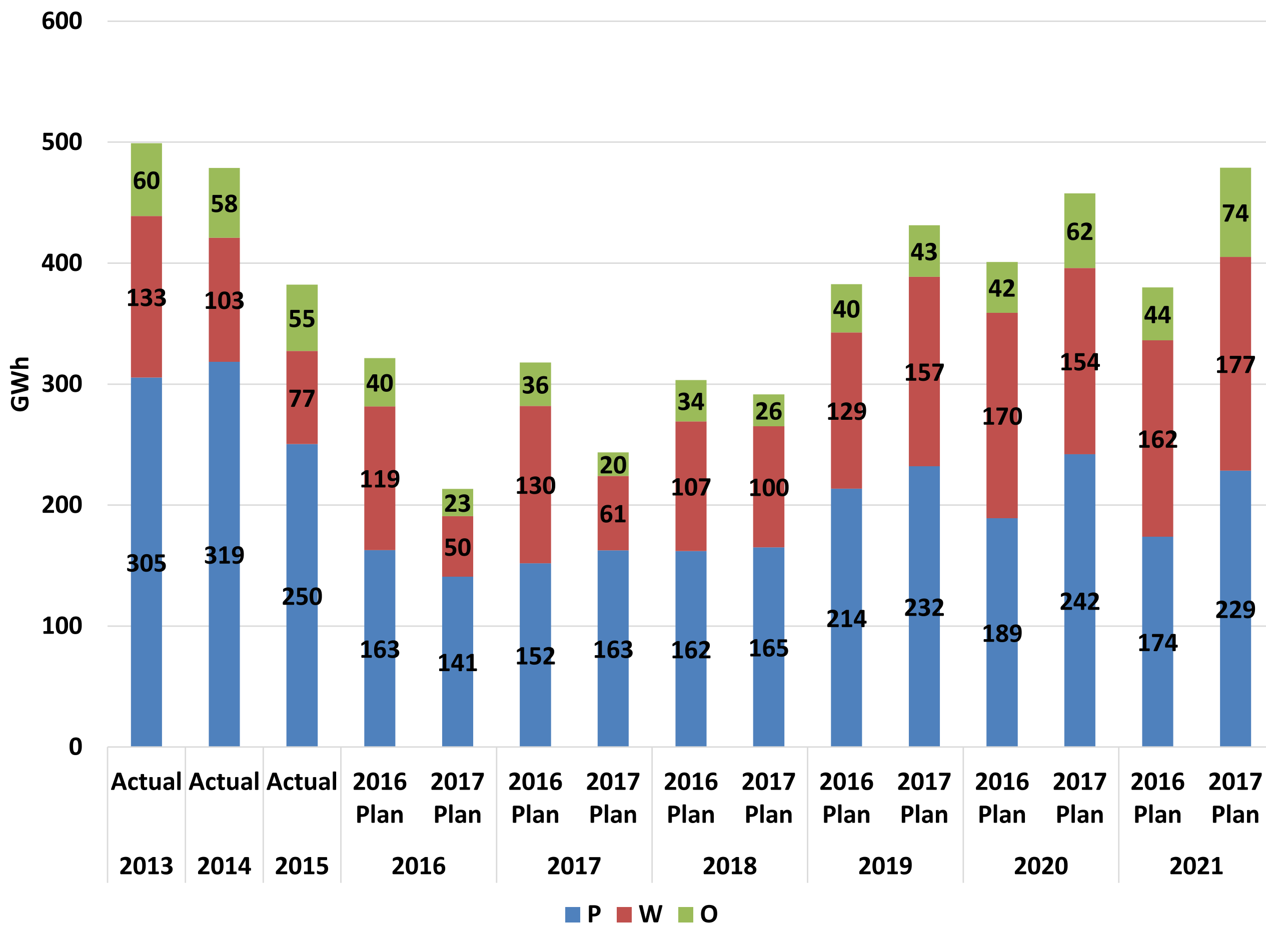
OSS volumes are lower in 2017-2018, and higher in 2019-2021



2017 Plan in 2016: 6 + 6

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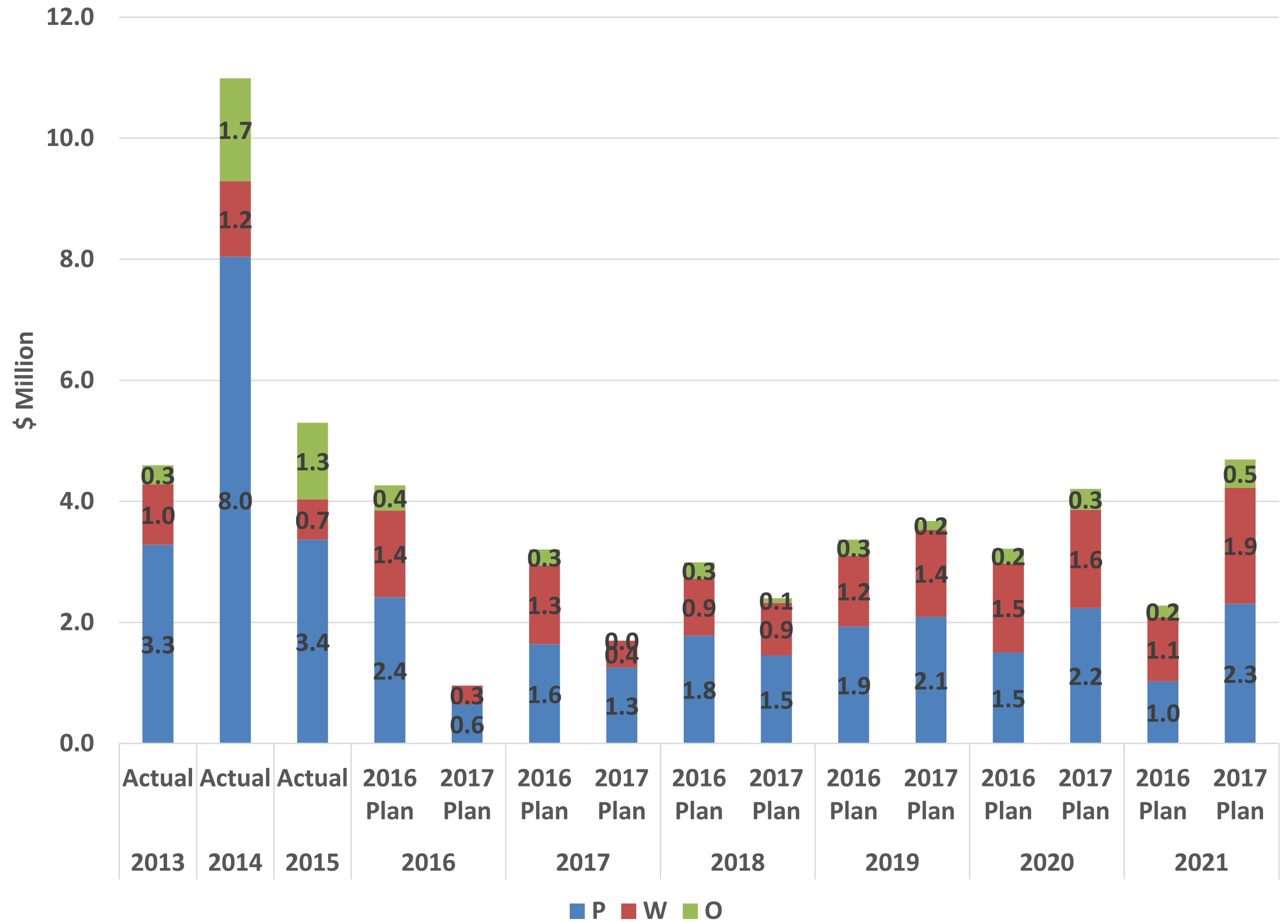
OSS Contribution by Peak Type



2017 Plan in 2016: 6 + 6

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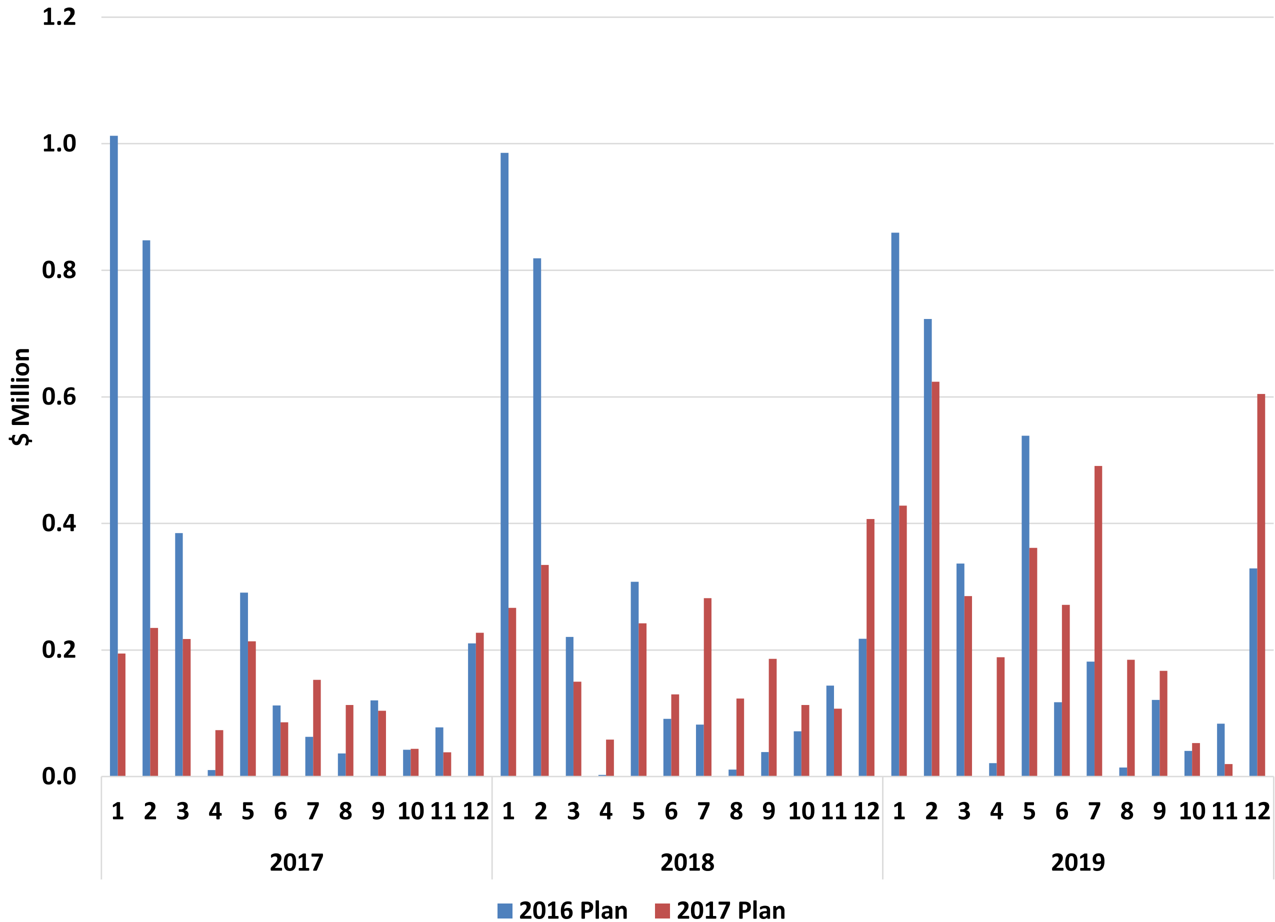
Removal of winter premium pricing results in OSS contribution more evenly spread between winter and summer



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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)

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FGD O&M decreases in 2017 Plan

FGD	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	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

SCR O&M decreases in 2017 Plan

SCR ($/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	0.00	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			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	0.00	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)

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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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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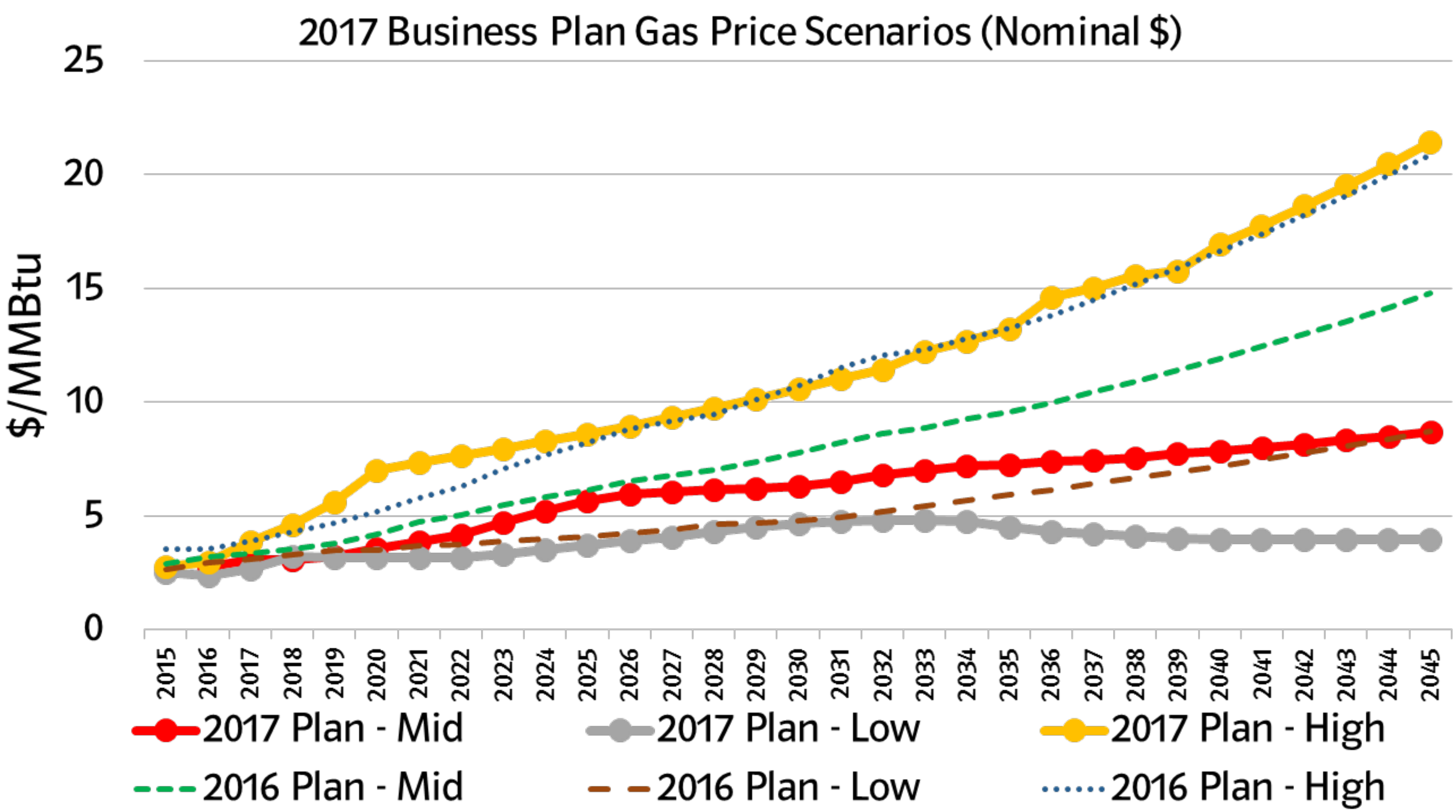
High/Low natural gas curves reflect wide range of prices



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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)**

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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

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. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

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 CO_2 emissions from 1,844 to 1,509 lb CO_2/MWh(net) beginning 2022 (proposed rule began interim compliance in 2020)***
- ***Changed Kentucky's proposed final (2030) limit on CO_2 emissions from 1,763 to 1,286 lb CO_2/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

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).

PPL companies

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
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.

PPL companies

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**

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LG&E KU PPL companies

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

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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	
2015 Actual	23,996
Baghouse Operations and Maintenance	583
Sorbent Injection systems'	(510)
Sorbent reactant (Hydrated Lime)	1,643
Landfill Operations and Maintenance	2,407
Mercury Additive	6,447
Other	10
2016 FC	34,576
Mercury Additive	(2,289)
Beneficial Reuse	500
Landfill Operations and Maintenance (TC)	628
Baghouse Operations and Maintenance	260
Sorbent reactant (Hydrated Lime)	(1,484)
Other	290
2017 Budget	32,482
Sorbent reactant (Hydrated Lime)	396
Landfill Operations and Maintenance (TC)	2,999
Other	167
2018 Plan	36,044
Landfill Operations and Maintenance (TC)	1,848
Sorbent reactant (Hydrated Lime)	283
Other	126
2019 Plan	38,300
Sorbent reactant (Hydrated Lime)	1,010
Landfill Operations and Maintenance	314
Mercury Additive	345
Other	228
2020 Plan	40,196
Sorbent reactant (Hydrated Lime)	331
Mercury Additive	336
Other	467
2021 Plan	41,330

Non Mechanism	
2015 Actual	26,206
Cane Run closure	(3,687)
Scrubber reactant (limestone)	347
Mercury Additive	1,055
Sorbent reactant (Hydrated Lime)	(634)
NOX reduction agent (Ammonia)	(1,016)
Other	252
2016 FC	22,523
NOX reduction agent (Ammonia)	289
Mercury Additive	(684)
Scrubber reactant (limestone)	252
Sorbent reactant (Hydrated Lime)	597
Other	(110)
2017 Budget	22,867
Ash Pond hauling MC	(583)
Other	193
2018 Plan	22,477
Scrubber reactant (limestone)	271
Other	186
2019 Plan	22,935
Scrubber reactant (limestone)	519
Sorbent reactant (Hydrated Lime)	63
Other	239
2020 Plan	23,756
Scrubber reactant (limestone)	490
Mercury Additive	427
Sorbent reactant (Hydrated Lime)	179
Other	123
2021 Plan	24,975

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LG&E KU PPL companies

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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Electric Distribution Operations

2017 Business Plan

September 2016

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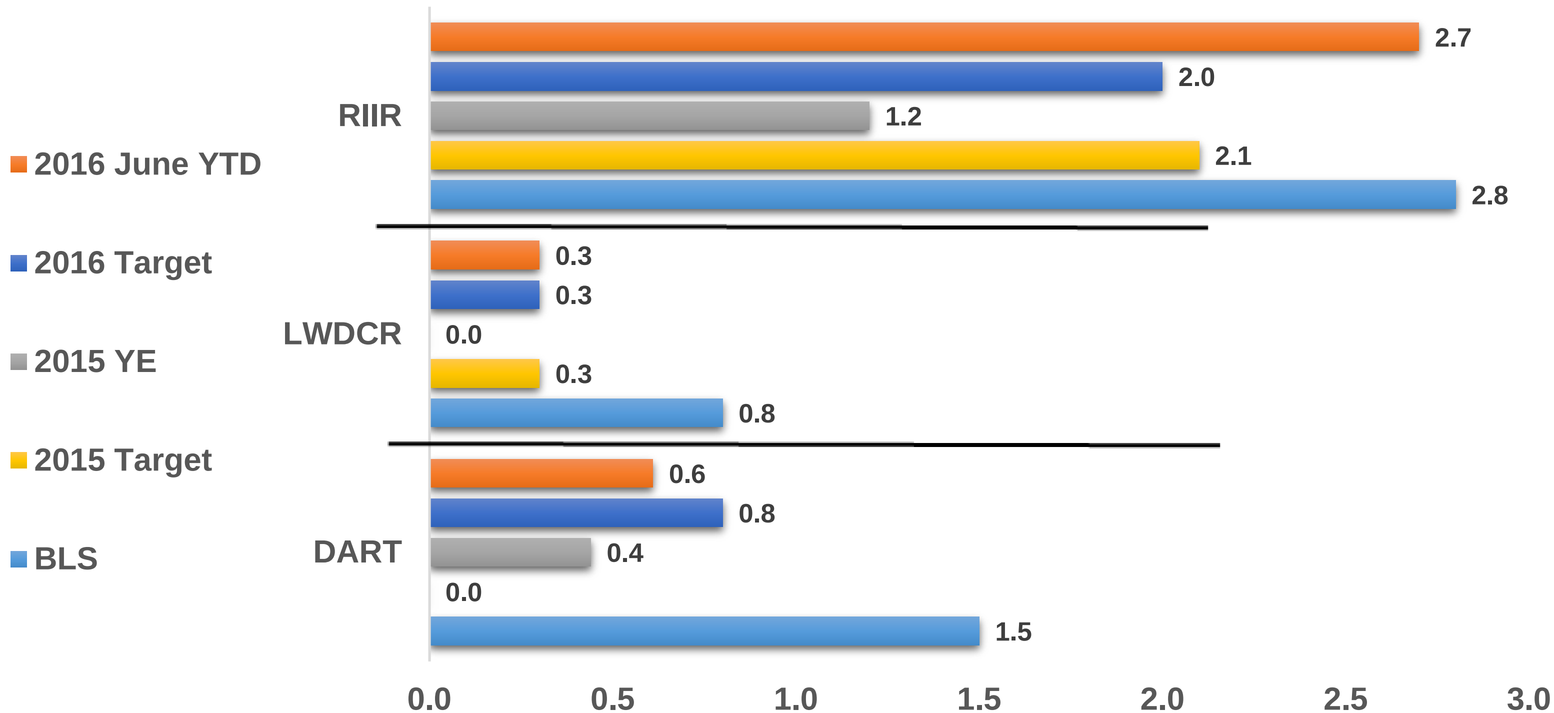
Plan Highlights

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



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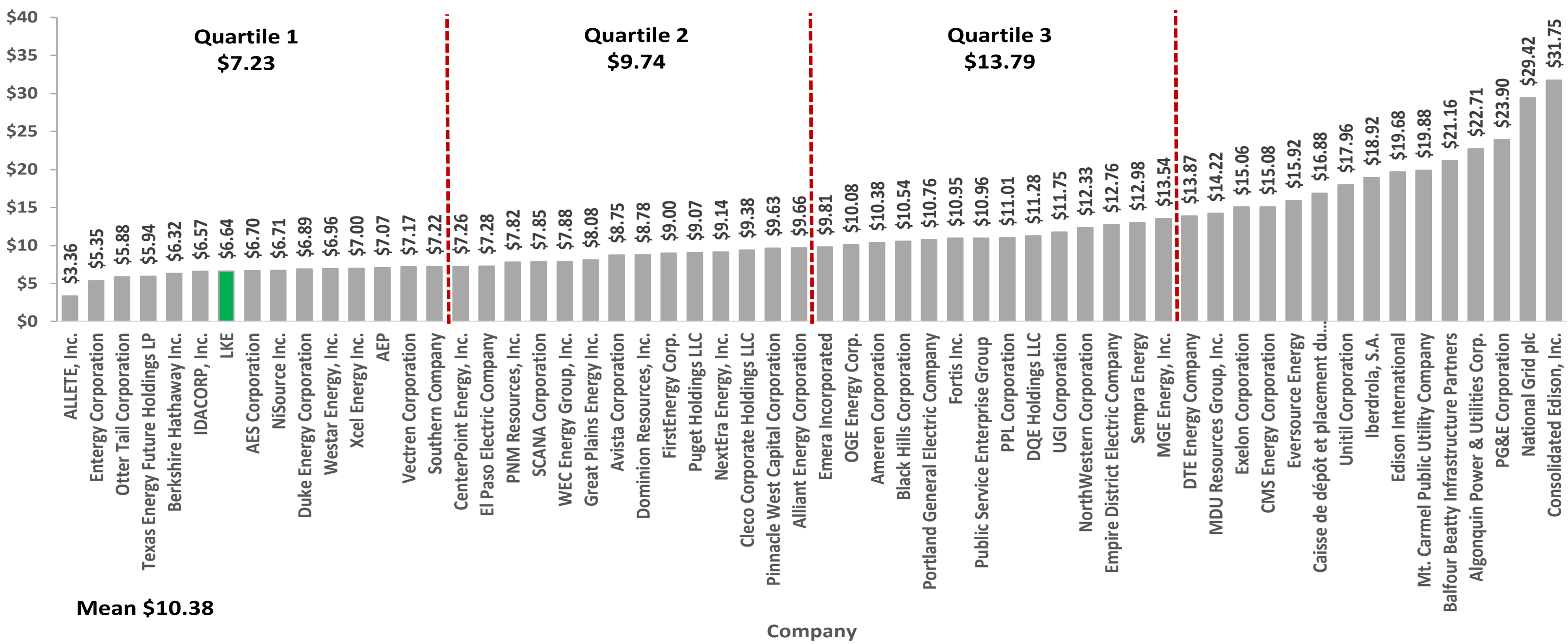
Plan Highlights

Total DO Electric Cash Cost per MWh



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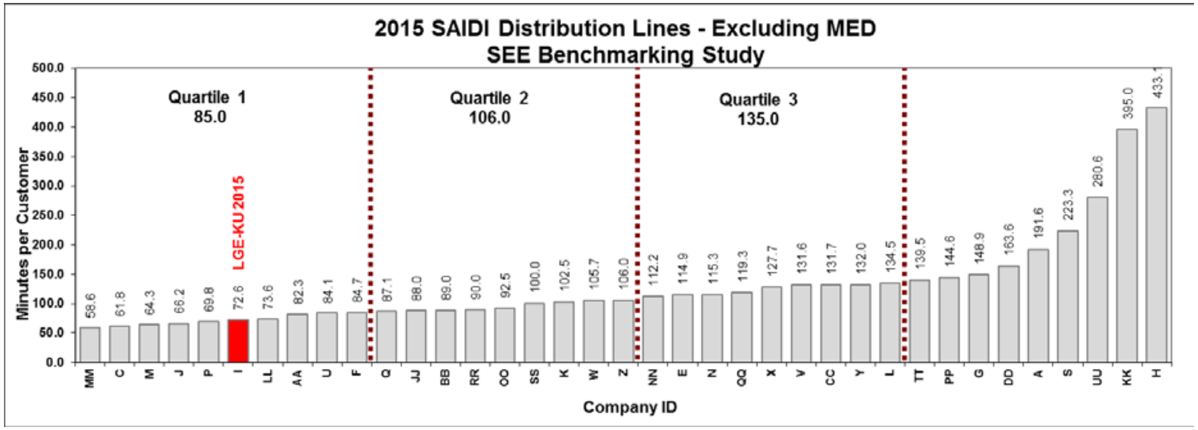
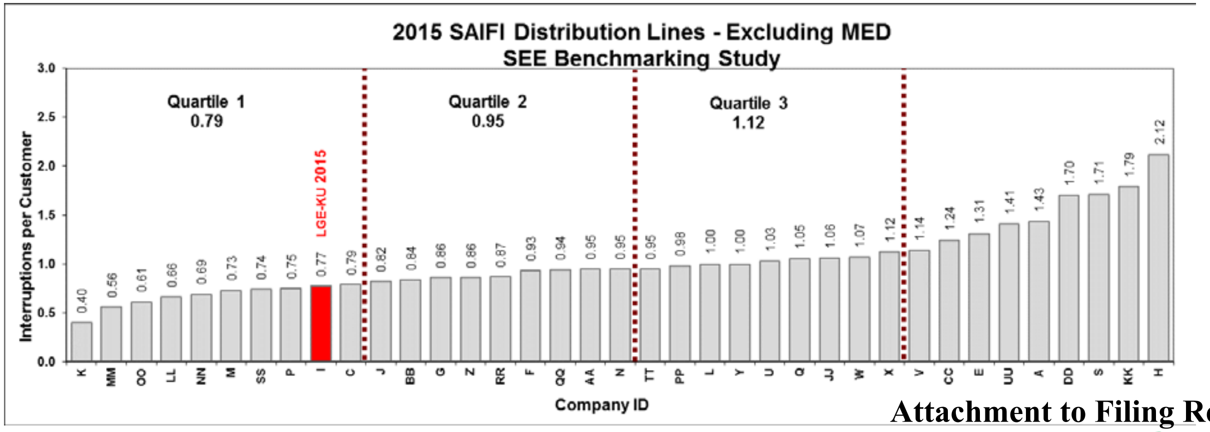
Plan Highlights

Reliability Performance





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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*

PPL companies

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

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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.*

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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.

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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

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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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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PPL companies

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.

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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	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

LG&E KU

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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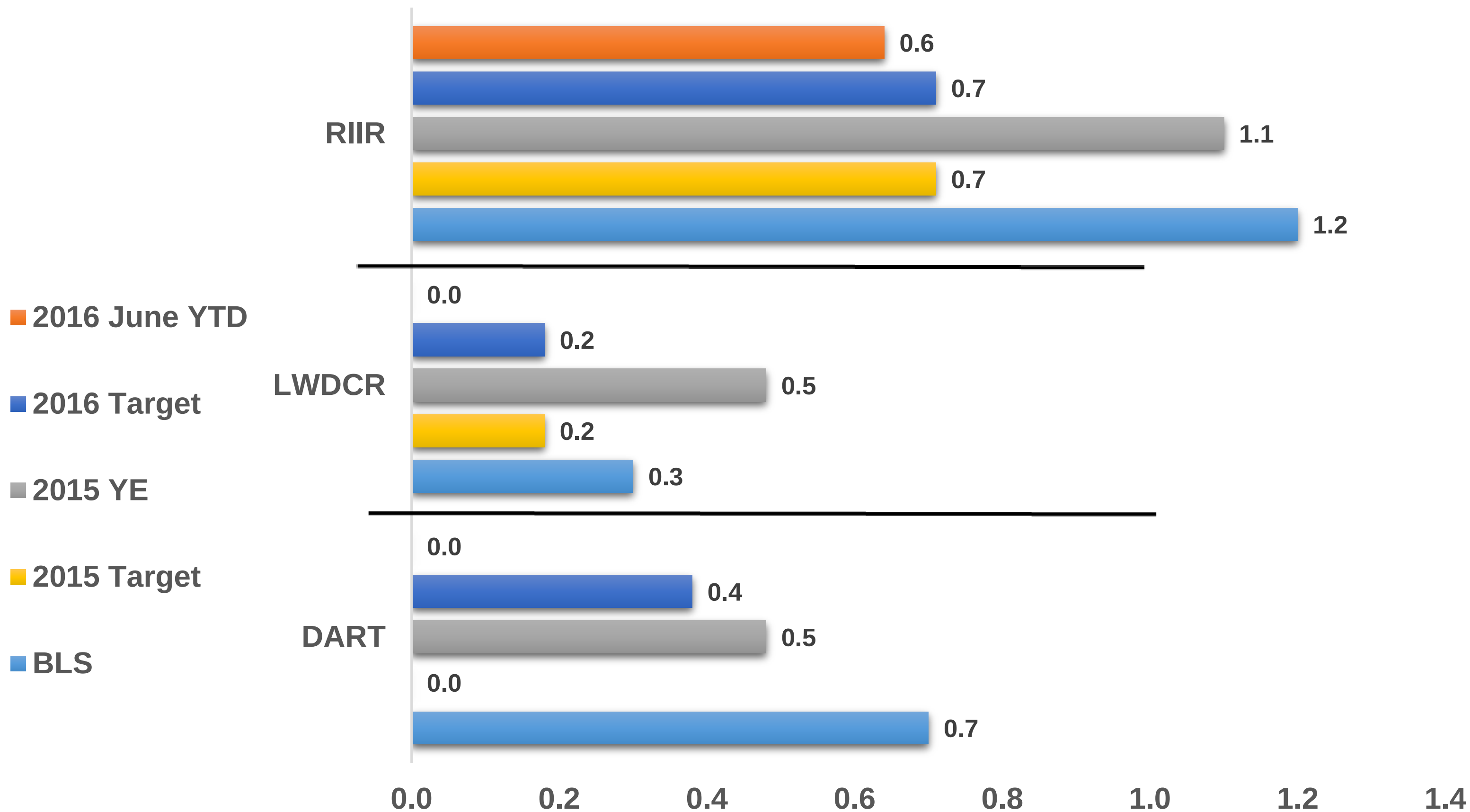
Safety Performance – Customer Service



2014 BLS - most recent data

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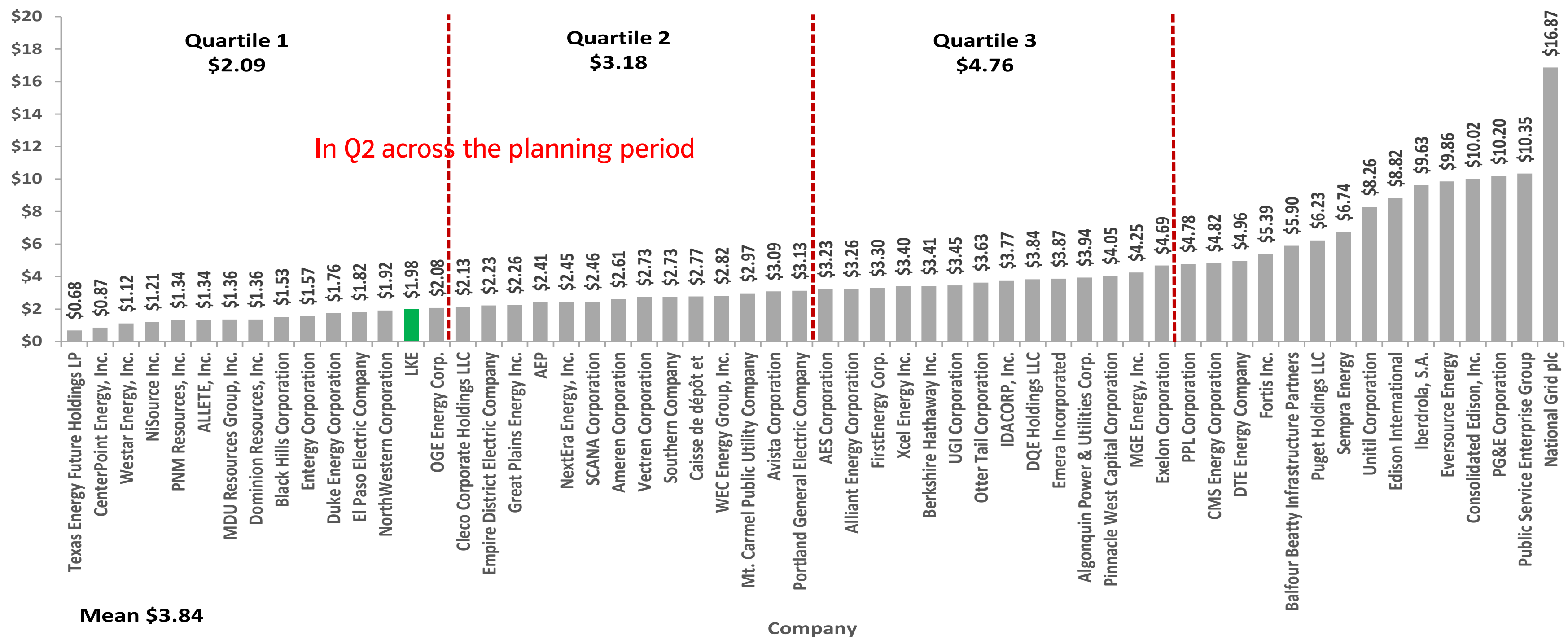
LG&E KU PPL companies

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)



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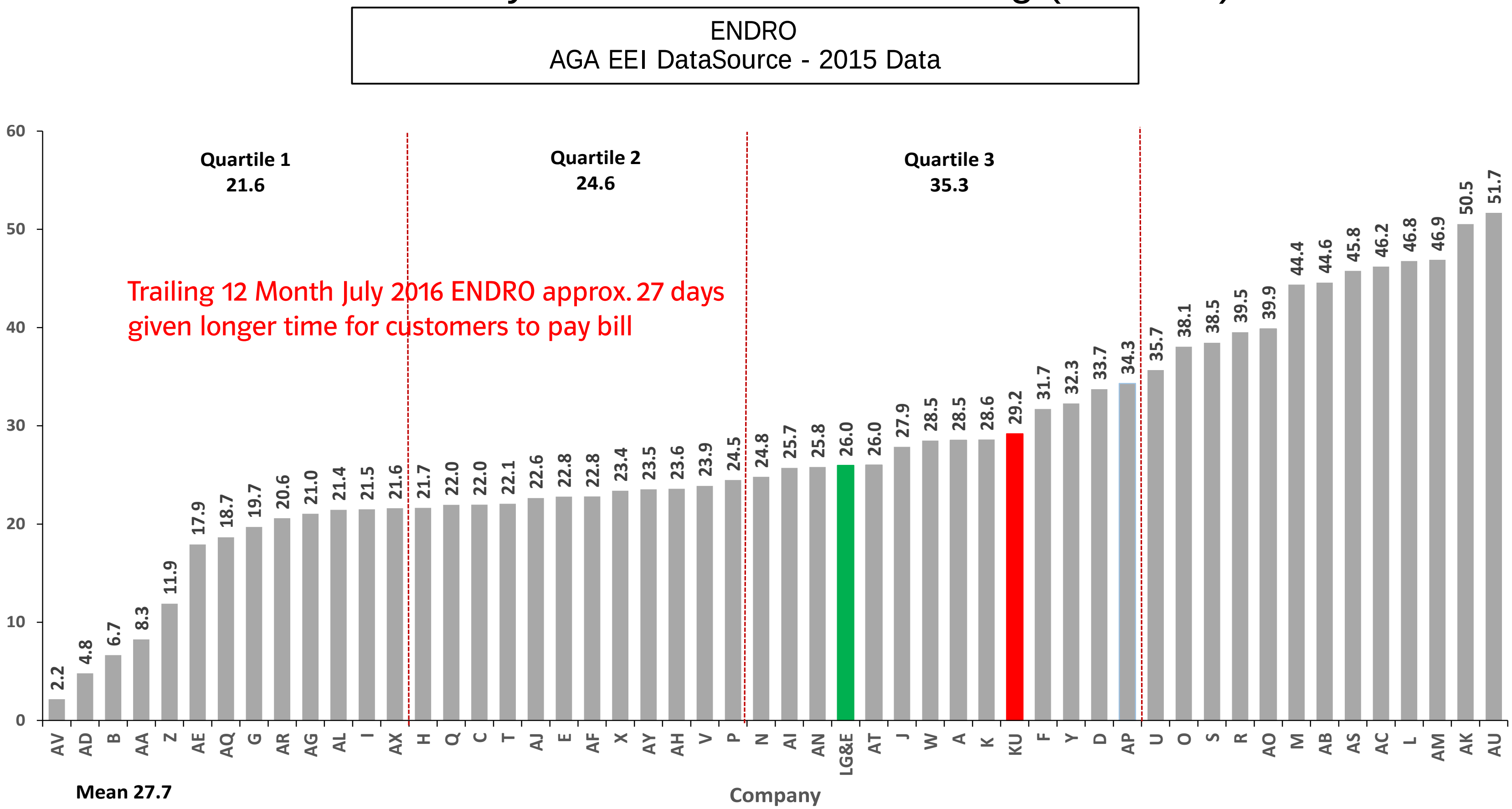
PPL companies

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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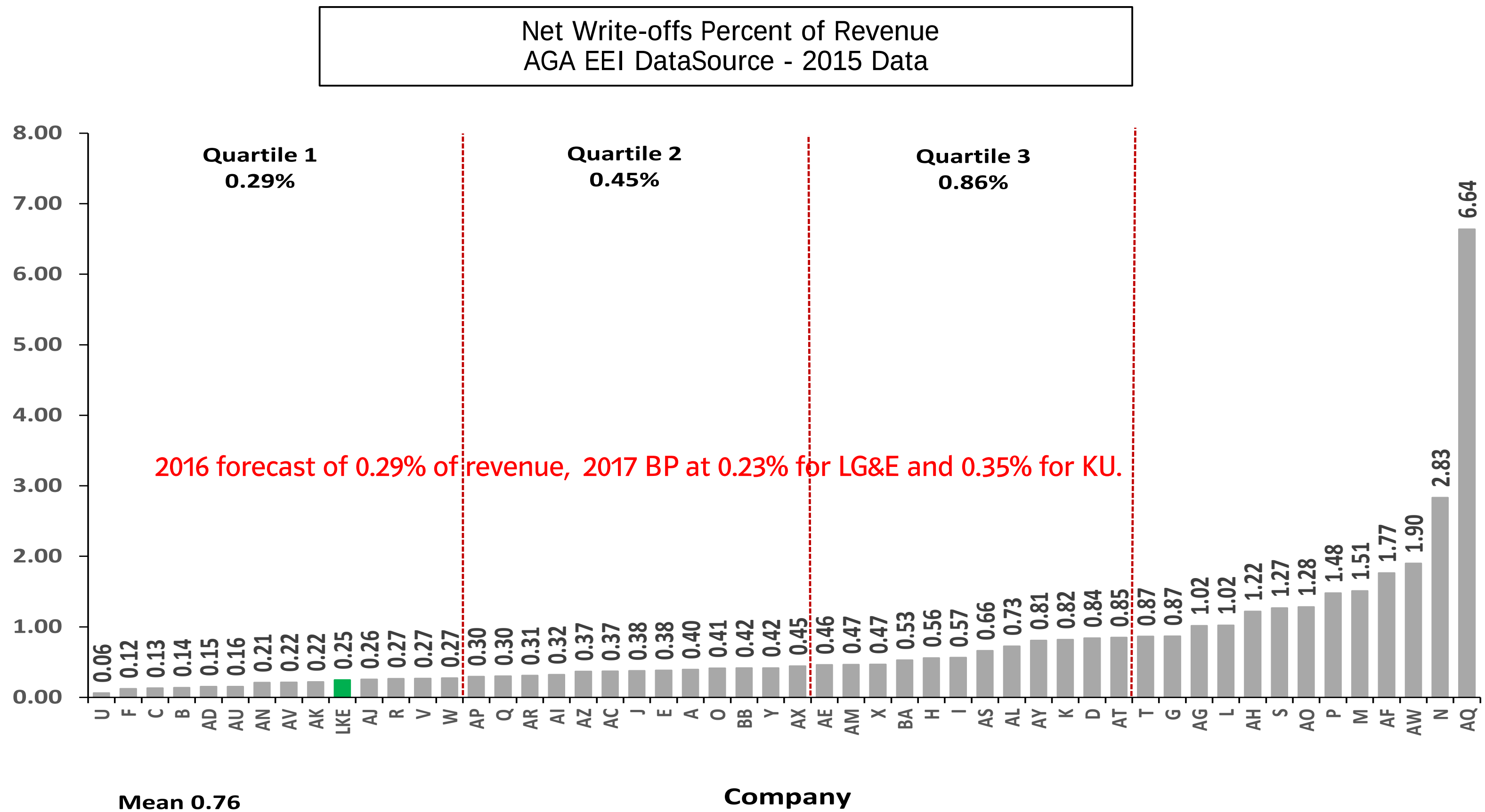
LG&E KU
PPL companies

Net Write-Offs as a Percent of Revenues to Ultimate Customers



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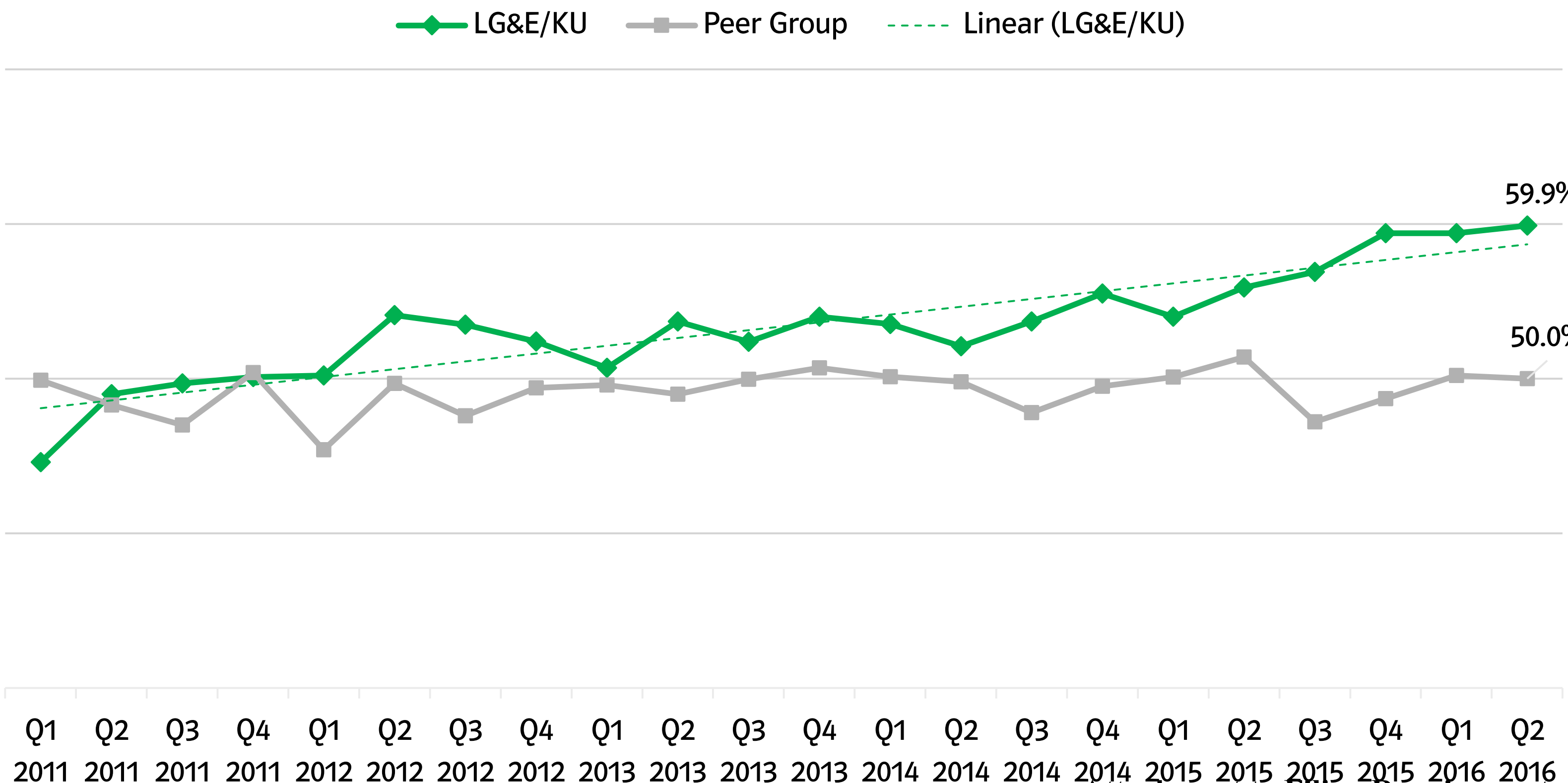
LG&E KU PPL companies

Residential Customers – Satisfaction Survey

Measured as “Top Two Box” (score of 9 or 10 on 10-point scale)



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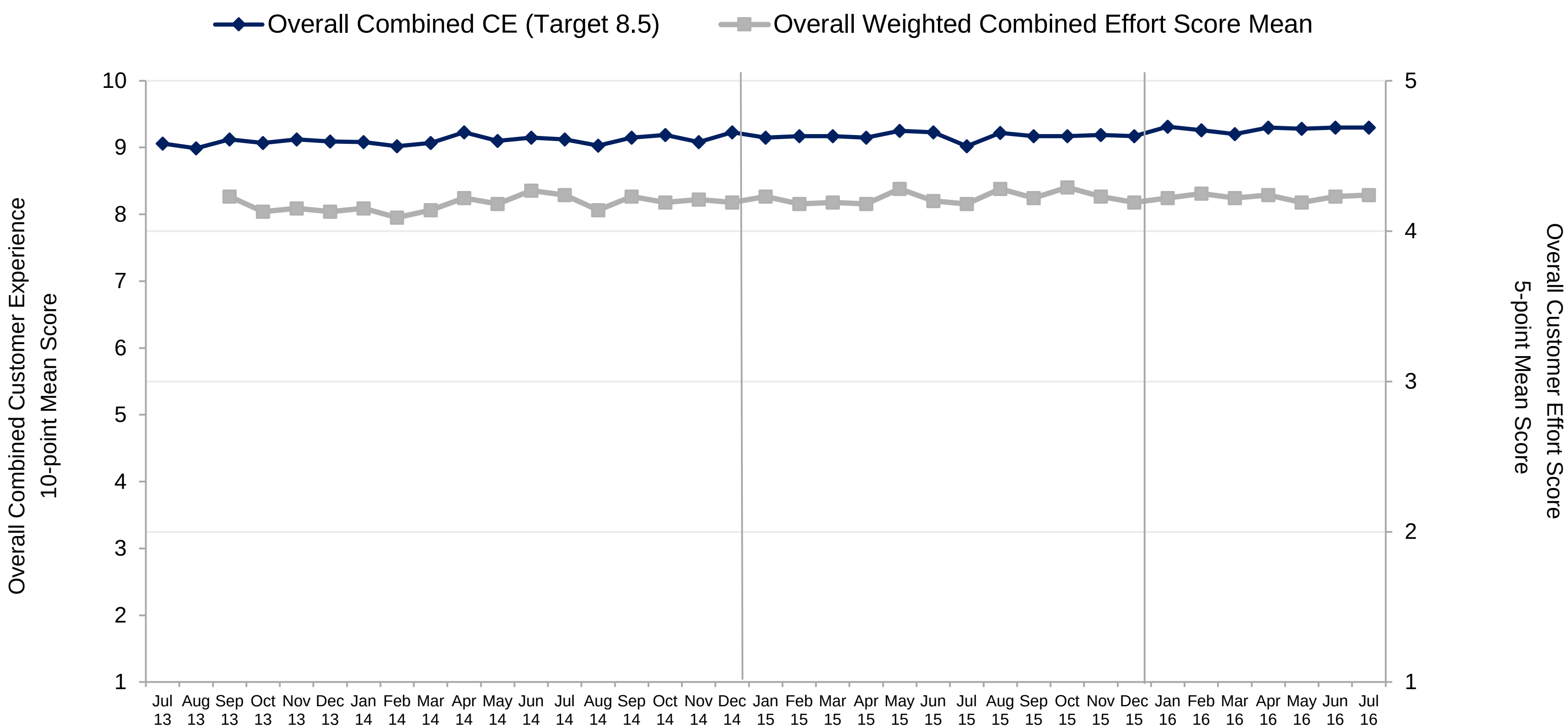
Plan Highlights

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.
Note: Residential and Business IVR transaction surveys were discontinued in 2016.

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LG&E KU
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*

- 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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LG&E KU 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
Mechanism recoverable					
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

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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
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)	

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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LG&E KU
PPL companies

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**

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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**

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**

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.

PPL companies

Transmission

2017 Business Plan

September 2016

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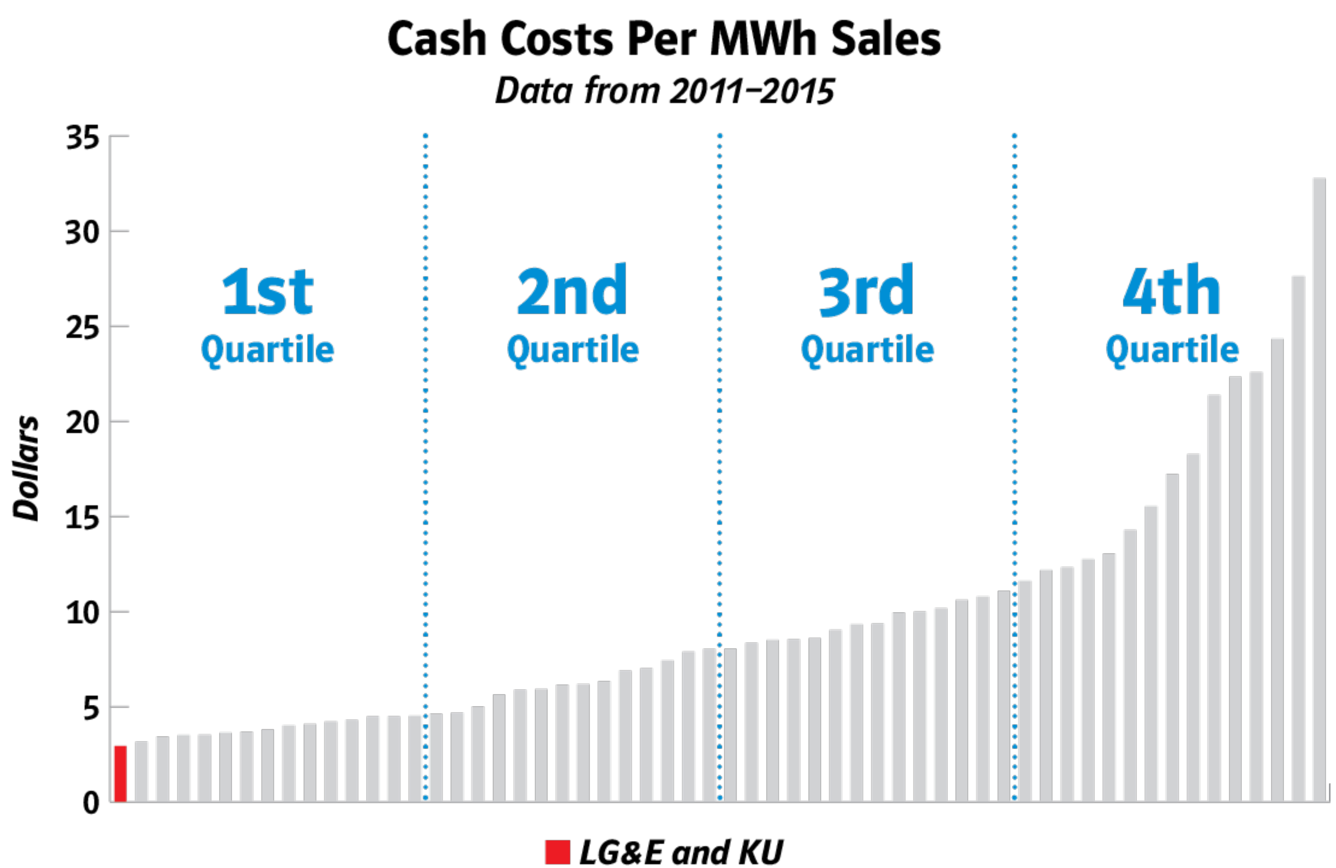
Plan Highlights

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.

PPL companies

Plan Highlights

FERC Benchmarking Data



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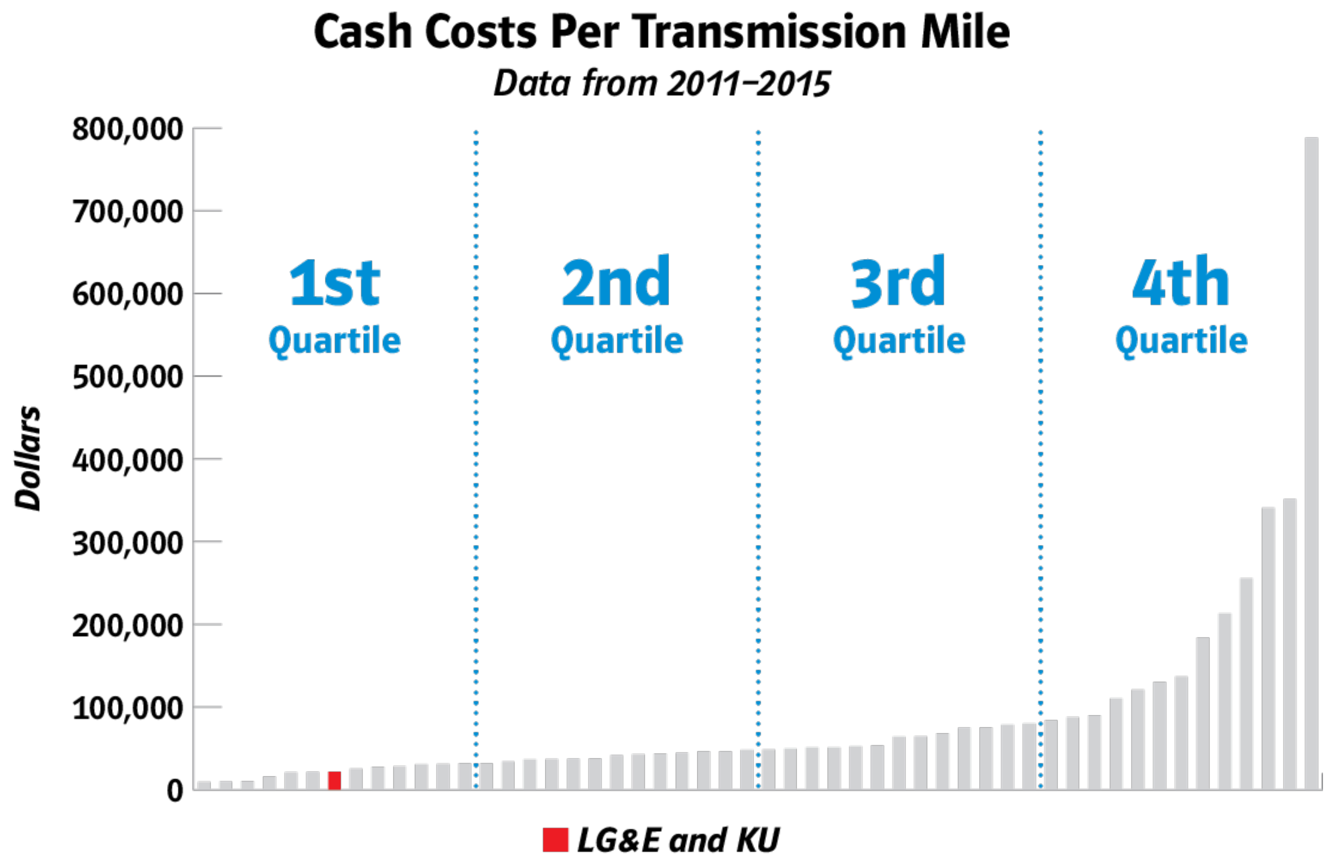
Plan Highlights

FERC Benchmarking Data



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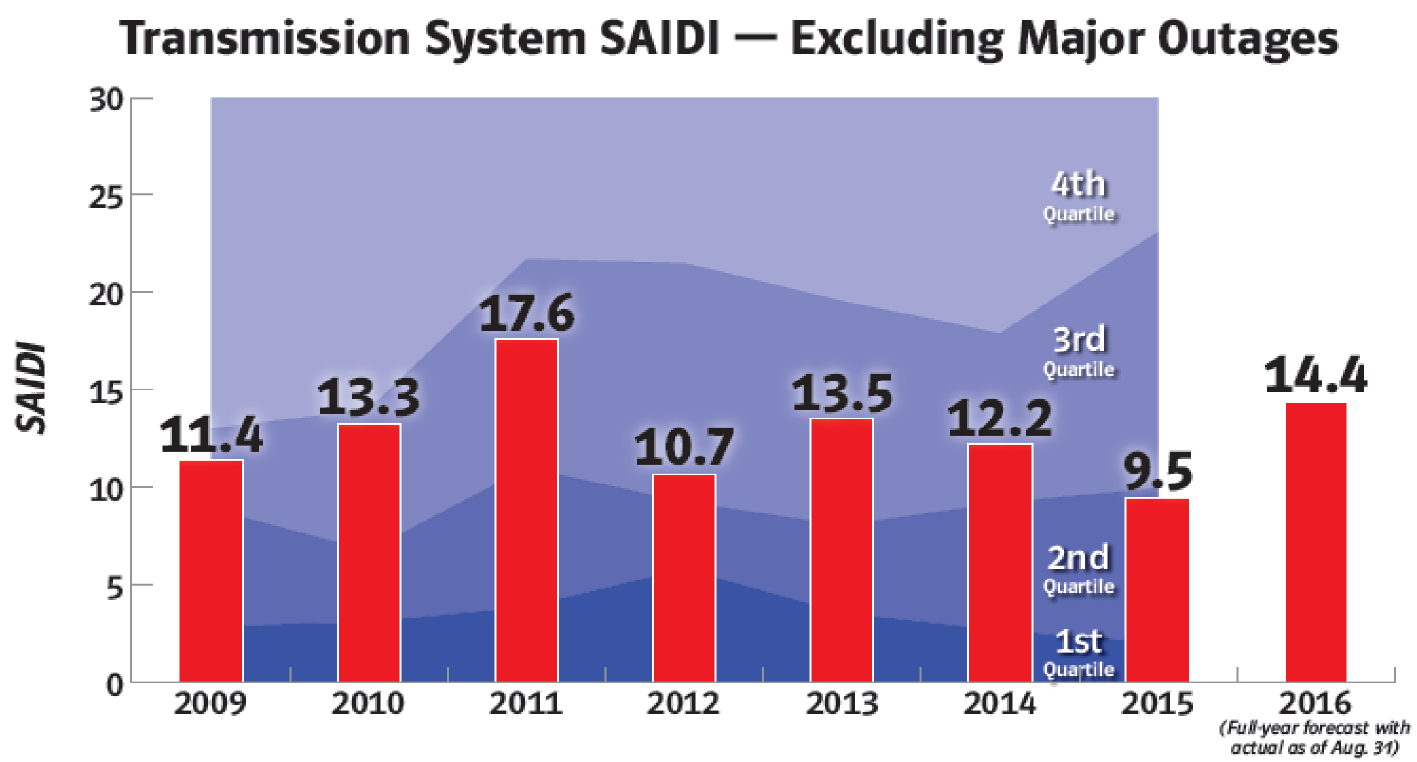
Plan Highlights

Historical Reliability Performance



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.

PPL companies

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**

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

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)

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							
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

PPL companies

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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LG&E KU PPL companies

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

LG&E KU PPL companies

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

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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)	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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PPL companies

PPL companies

Generation Services

2017 Business Plan

September 2016

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PPL companies

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**

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

PPL companies

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	

LG&E KU PPL companies

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**

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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	-	-	-	-	-

LG&E KU PPL companies

PPL companies

Energy Supply and Analysis

2017 Business Plan

September 2016

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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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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

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

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)**	**-**	**-**	**-**

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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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
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.)

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

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
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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PPL companies

Plan Risks

- Stricter Federal regulations pertaining to Operator qualifications for Gas Pipeline
- Aging equipment in Dielectric Testing Lab
- Ongoing Federal OSHA regulations

Appendix

PPL companies

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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PPL companies

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

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

LG&E KU PPL companies

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.*

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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PPL companies

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

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
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%.*

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.*

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

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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

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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**

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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

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

Excludes Interns

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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

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

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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.

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.

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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.*

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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

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**

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

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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.*

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

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
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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LG&E KU PPL companies

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.

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

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**

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PPL companies

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

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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
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.

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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**

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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

LG&E KU PPL companies

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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]	[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

LG&E KU
PPL companies

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

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Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
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 - Kentucky Utilities Company

Total Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	170,991,551	156,866,757	145,014,222	130,494,433	136,770,374	151,510,767	177,674,108	181,381,116	155,913,017	145,747,207	150,335,084	174,455,694	1,877,154,328
Total Operating Revenues	170,991,551	156,866,757	145,014,222	130,494,433	136,770,374	151,510,767	177,674,108	181,381,116	155,913,017	145,747,207	150,335,084	174,455,694	1,877,154,328
Operating Expenses													
Fuel for Electric Generation	56,328,658	54,685,604	48,391,038	43,731,378	48,720,336	55,892,831	61,408,106	62,497,587	48,857,350	42,826,021	45,533,405	55,882,391	624,754,704
Power Purchased	10,769,802	7,353,969	8,206,739	7,754,963	3,315,960	3,287,968	3,612,862	4,084,907	3,920,829	9,166,452	9,310,024	8,209,382	78,993,857
Other Operation Expenses	26,185,623	24,170,318	25,742,820	24,435,560	26,372,696	28,132,593	27,579,325	27,564,170	27,972,361	26,841,314	24,599,055	26,673,366	316,269,201
Maintenance	7,986,563	8,715,407	17,764,364	17,605,434	11,167,603	10,638,380	9,806,911	9,766,488	10,803,145	14,857,365	12,840,472	9,208,517	141,160,650
Depreciation & Amortization Expense	17,771,428	17,795,616	17,825,737	18,052,400	18,770,772	19,315,261	19,360,584	19,382,423	19,426,282	19,475,402	19,680,832	20,166,402	227,023,139
Current Income Taxes	16,314,866	13,288,840	5,370,947	3,456,704	7,132,935	8,126,598	17,822,454	18,676,592	12,294,901	8,107,054	10,529,869	15,461,977	136,583,736
Property and Other Taxes	3,320,512	3,323,180	3,320,143	3,322,161	3,322,337	3,321,486	3,325,253	3,325,998	3,325,221	3,324,676	3,328,170	3,328,178	39,887,315
Total Operating Expenses	138,677,452	129,332,933	126,621,788	118,358,601	118,802,638	128,715,118	142,915,494	145,298,165	126,600,088	124,598,284	125,821,827	138,930,213	1,564,672,601
Net Operating Income	32,314,099	27,533,823	18,392,434	12,135,833	17,967,735	22,795,649	34,758,613	36,082,951	29,312,929	21,148,923	24,513,257	35,525,481	312,481,727
AFUDC - Equity	98,983	100,126	101,225	102,056	51,303	-	-	-	-	-	-	-	453,693
Other Income less deductions	(34,749)	163,244	71,609	75,781	162,143	131,753	171,365	150,704	119,118	153,557	201,866	125,830	1,492,220
Income before Interest Charges	32,378,333	27,797,194	18,565,268	12,313,670	18,181,182	22,927,402	34,929,978	36,233,654	29,432,046	21,302,480	24,715,123	35,651,311	314,427,641
Interest Charges	6,623,617	6,596,302	6,633,996	6,641,589	6,699,257	6,708,927	6,700,171	6,682,919	6,679,079	8,350,401	7,909,235	7,917,123	84,142,616
Net Income	25,754,717	21,200,891	11,931,272	5,672,080	11,481,924	16,218,476	28,229,807	29,550,736	22,752,967	12,952,079	16,805,888	27,734,188	230,285,024

2016 Budget - Kentucky Utilities Company

Total 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	179,329,369	165,093,823	155,275,588	138,823,240	143,551,057	158,890,867	171,219,155	175,553,065	150,918,713	142,112,170	145,885,083	165,413,326	1,892,065,457	1,905,557,826
Total Operating Revenues	179,329,369	165,093,823	155,275,588	138,823,240	143,551,057	158,890,867	171,219,155	175,553,065	150,918,713	142,112,170	145,885,083	165,413,326	1,892,065,457	1,905,557,826
Operating Expenses														
Fuel for Electric Generation	54,448,748	49,467,938	45,313,603	37,628,253	46,302,882	51,883,006	54,204,504	56,383,182	44,156,195	43,768,278	44,820,562	50,560,315	578,937,466	584,972,385
Power Purchased	6,726,319	5,689,160	6,189,262	7,228,871	1,834,712	2,684,738	3,412,516	3,393,803	3,288,921	3,262,041	2,921,006	5,113,676	51,745,025	61,229,749
Other Operation Expenses	24,948,365	25,070,720	26,287,025	23,529,431	26,064,930	26,589,623	26,874,252	28,261,946	27,506,407	25,465,736	24,878,719	25,188,420	310,665,574	311,870,857
Maintenance	8,862,482	10,273,050	14,212,094	13,247,859	10,119,665	10,569,699	9,986,107	9,873,959	10,512,092	12,851,426	11,655,799	8,949,673	131,113,905	132,557,422
Depreciation & Amortization Expense	19,967,659	19,990,884	20,021,907	20,063,410	20,108,941	20,152,817	20,196,674	20,234,811	20,270,945	20,317,906	20,353,493	20,570,177	242,249,625	241,173,189
Current Income Taxes	20,511,417	16,715,326	12,087,768	9,907,336	10,680,669	13,537,483	17,460,620	17,802,794	12,799,195	9,642,897	11,512,729	16,658,586	169,316,820	167,137,351
Property and Other Taxes	3,459,119	3,460,314	3,464,574	3,463,026	3,459,860	3,457,819	3,462,055	3,470,155	3,466,339	3,467,308	3,464,433	3,460,028	41,555,030	41,286,917
Total Operating Expenses	138,924,110	130,667,392	127,576,234	115,068,186	118,571,659	128,875,185	135,596,728	139,420,650	122,000,093	118,775,592	119,606,742	130,500,874	1,525,583,445	1,540,227,869
Net Operating Income	40,405,260	34,426,431	27,699,354	23,755,054	24,979,398	30,015,682	35,622,428	36,132,415	28,918,619	23,336,578	26,278,341	34,912,451	366,482,012	365,329,957
AFUDC - Equity	5,773	7,719	9,613	10,516	11,178	13,765	16,764	18,487	21,060	23,004	24,753	24,250	186,882	137,879
Other Income less deductions	(118,794)	96,964	66,702	22,956	146,133	94,917	177,244	165,332	147,730	123,808	169,426	134,916	1,227,334	1,250,688
Income before Interest Charges	40,292,239	34,531,114	27,775,668	23,788,527	25,136,709	30,124,365	35,816,435	36,316,234	29,087,410	23,483,390	26,472,521	35,071,617	367,896,228	366,718,523
Interest Charges	8,126,498	8,110,167	8,110,751	8,132,061	8,141,734	8,150,020	8,135,535	8,108,072	8,212,581	8,128,937	8,133,766	8,144,491	97,634,613	97,182,714
Net Income	32,165,742	26,420,947	19,664,918	15,656,465	16,994,975	21,974,345	27,680,900	28,208,163	20,874,828	15,354,452	18,338,755	26,927,126	270,261,615	269,535,810

Total 12 months Preceding Filing Date[1] - Sum of November and December 2015 Budget plus January through October of the 2016 Budget

2017 Budget - Kentucky Utilities Company

Total 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	175,033,100	158,520,837	149,252,577	129,364,051	136,629,662	152,246,144	164,218,939	167,356,265	142,813,326	136,298,255	144,601,567	164,630,778	1,820,965,501	1,881,196,202
Total Operating Revenues	175,033,100	158,520,837	149,252,577	129,364,051	136,629,662	152,246,144	164,218,939	167,356,265	142,813,326	136,298,255	144,601,567	164,630,778	1,820,965,501	1,881,196,202
Operating Expenses														
Fuel for Electric Generation	49,350,784	43,528,578	39,477,807	36,762,625	38,738,673	46,158,781	49,483,871	50,361,583	38,870,421	38,798,011	41,810,982	44,951,834	518,293,951	567,900,143
Power Purchased	6,929,892	6,485,397	7,353,892	2,583,129	3,660,516	2,886,302	2,923,999	3,569,729	3,465,024	3,332,751	3,650,994	6,967,805	53,809,430	52,744,835
Other Operation Expenses	25,070,707	23,830,770	25,434,472	23,542,192	25,062,801	27,031,614	27,347,887	28,395,575	27,278,103	26,928,770	25,157,870	26,077,607	311,158,367	309,547,966
Maintenance	8,810,661	9,615,640	12,537,164	14,863,012	10,299,407	10,665,011	10,561,112	10,020,072	10,506,925	16,861,376	9,637,700	9,214,660	133,592,740	130,404,674
Depreciation & Amoritization Expense	20,322,981	20,336,645	20,350,175	20,376,467	20,412,838	20,453,256	25,579,756	25,683,310	25,808,108	25,896,087	26,017,741	26,193,967	277,431,331	242,950,708
Regulatory Debits	49,421	51,127	52,854	56,358	59,888	67,515	77,370	87,309	97,309	109,256	121,182	133,180	962,769	100,549
Current Income Taxes	20,579,048	16,787,152	12,347,815	7,623,448	10,416,730	12,705,313	14,253,482	14,641,524	9,524,977	4,962,147	10,345,668	15,072,231	149,259,533	37,366,200
Property and Other Taxes	3,542,100	3,537,919	3,545,176	3,539,865	3,544,888	3,539,638	3,535,477	3,547,113	3,539,303	3,548,093	3,541,603	3,532,826	42,494,000	41,715,616
Total Operating Expenses	134,655,595	124,173,229	121,099,355	109,347,096	112,195,740	123,507,430	133,762,953	136,306,215	119,090,171	120,436,490	120,283,739	132,144,109	1,487,002,121	1,514,820,766
Net Operating Income	40,377,505	34,347,609	28,153,222	20,016,955	24,433,922	28,738,714	30,455,986	31,050,049	23,723,155	15,861,765	24,317,828	32,486,669	333,963,380	366,375,435
AFUDC - Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	173,390
Other Income less deductions	(107,117)	113,494	55,080	89,764	111,468	104,915	140,725	120,095	116,270	102,520	57,390	85,589	(990,194)	1,255,541
Income before Interest Charges	40,270,388	34,461,103	28,208,302	20,106,719	24,545,390	28,843,629	30,596,711	31,170,145	23,839,426	15,964,285	24,375,218	32,572,258	334,953,573	367,804,366
Interest Charges	7,993,083	7,919,095	7,974,426	7,981,817	8,011,393	7,998,397	8,007,093	7,991,660	7,978,175	8,006,716	8,006,915	8,028,648	95,897,417	97,310,126
Net Income	32,277,306	26,542,008	20,233,876	12,124,902	16,533,997	20,845,232	22,589,618	23,178,485	15,861,251	7,957,569	16,368,303	24,543,609	239,056,156	270,494,241

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 - Kentucky Utilities Company

Total 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	177,116,674	160,389,092	151,415,007	131,759,195	139,293,477	154,154,049	165,892,165	169,360,250	145,263,230	138,774,598	146,613,743	167,022,000	1,847,053,479	1,834,046,624
Total Operating Revenues	177,116,674	160,389,092	151,415,007	131,759,195	139,293,477	154,154,049	165,892,165	169,360,250	145,263,230	138,774,598	146,613,743	167,022,000	1,847,053,479	1,834,046,624
Operating Expenses														
Fuel for Electric Generation	48,666,071	42,725,510	38,122,145	34,440,805	38,920,959	45,050,615	48,634,772	50,143,371	37,824,355	38,453,843	39,731,225	45,073,093	507,786,765	512,202,807
Power Purchased	7,336,196	6,737,832	8,613,379	4,675,953	3,502,409	2,972,911	3,120,563	2,899,186	4,082,665	3,422,454	5,029,994	6,456,168	58,849,711	57,748,982
Other Operation Expenses	26,311,263	24,841,137	26,158,293	24,968,489	26,122,658	27,377,128	27,634,476	29,153,324	27,373,907	27,647,868	25,937,794	26,917,042	320,443,381	316,964,780
Maintenance	9,477,989	9,977,265	17,462,499	18,567,817	14,440,024	12,564,018	11,322,565	10,868,288	13,583,751	17,450,848	14,222,027	9,656,672	159,593,763	149,291,457
Depreciation & Amortization Expense	26,333,714	26,354,412	26,385,568	26,441,080	26,485,353	26,545,304	26,735,356	26,906,037	26,965,830	27,036,827	27,139,877	27,654,661	320,984,019	313,724,400
Regulatory Debits	150,864	162,621	174,482	198,418	222,525	246,832	283,635	320,782	358,233	408,708	459,674	511,184	3,497,958	1,781,349
Current Income Taxes	18,262,703	14,686,715	8,558,352	4,109,320	6,868,954	10,449,207	14,092,029	14,443,958	8,766,043	4,818,281	8,605,950	14,845,132	128,506,645	131,735,280
Property and Other Taxes	3,773,992	3,767,018	3,770,189	3,771,123	3,773,683	3,765,104	3,773,723	3,779,905	3,771,513	3,783,831	3,773,888	3,766,616	45,270,580	43,865,521
Total Operating Expenses	140,312,792	129,252,511	129,244,906	117,173,005	120,336,565	128,971,119	135,597,120	138,514,851	122,726,297	123,022,659	124,900,428	134,880,568	1,544,932,821	1,527,314,576
Net Operating Income	36,803,882	31,136,581	22,170,101	14,586,190	18,956,912	25,182,930	30,295,045	30,845,399	22,536,933	15,751,939	21,713,315	32,141,433	302,120,658	306,732,048
AFUDC - Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Income less deductions	(87,999)	125,444	69,225	101,482	124,933	119,821	162,096	142,881	128,017	114,313	71,535	103,491	1,175,240	1,075,496
Income before Interest Charges	36,715,883	31,262,026	22,239,326	14,687,672	19,081,844	25,302,751	30,457,141	30,988,280	22,664,950	15,866,251	21,784,850	32,244,923	303,295,897	307,807,544
Interest Charges	8,057,728	8,007,212	8,054,561	8,070,671	8,106,853	8,097,435	8,099,744	8,097,325	8,095,173	8,122,860	8,134,966	8,151,285	97,095,812	- 96,413,666
Net Income	28,658,155	23,254,814	14,184,765	6,617,002	10,974,991	17,205,316	22,357,398	22,890,955	14,569,777	7,743,391	13,649,884	24,093,639	206,200,086	211,393,878

Kentucky Utilities Company
Case No. 2016-00370
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.

(SEAL)
NOTARY PUBLIC

My Commission Expires:

June 21, 2018

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
Fully Forecasted Test Period
Summary of 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
Trimble County	Trimble County CCRT - Landfill	N/A	$ 25,710,317	$ -	$ 25,710,317	$ 9,061,125	$ -	$ 9,061,125	$ -	Mar-16	Jul-18
	All Other Projects < 5%		$ 366,623,964	$ 445,269	$ 367,069,233	$ 2,156,683,536	$ 5,655,066	$ 2,162,338,602	$ 1,958,979,588		

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
Ghent	Ghent Process Water Pond	N/A	$ 34,615,000	$ -	$ 34,615,000	$ 108,573	$ -	$ 108,573	$ -	Jun-16	Dec-19
	All Other Projects < 5%		$ 512,610,458	$ -	$ 512,610,458	$ 1,117,755,869	$ 812,586	$ 1,118,568,455	$ 1,016,796,693		

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
Ghent	Ghent Process Water Pond	N/A	$ 66,763,967	$ -	$ 66,763,967	$ 108,573	$ -	$ 108,573	$ -	Jun-16	Dec-19
Brown	Brown Process Water Pond	N/A	$ 40,442,002	$ -	$ 40,442,002	$ 541	$ -	$ 541	$ -	Jun-16	Dec-19
NA	Advanced Metering Systems	N/A	$ 44,262,500	$ -	$ 44,262,500	$ -	$ -	$ -	$ -	Jan-17	Dec-19
	All Other Projects < 5%		$ 527,339,248	$ -	$ 527,339,248	$ 255,190,794	$ -	$ 255,190,794	$ 185,257,113		

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	Advanced Metering Systems	N/A	$ 47,840,000	$ -	$ 47,840,000	$ -	$ -	$ -	$ -	Jan-17	Dec-19
NA	Priority Transmission Line Replacement	N/A	$ 31,488,000	$ -	$ 31,488,000	$ -	$ -	$ -	$ -	Jan-19	Dec-19
	All Other Projects < 5%		$ 505,519,062	$ -	$ 505,519,062	$ 230,686,031	$ -	$ 230,686,031	$ 177,736,815		

Kentucky Utilities Company
Case No. 2016-00370
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 KU's response to Filing Requirement 807 KAR 5:001 Section 16(7)(f)[Tab No. 19].

Kentucky Utilities Company
Case No. 2016-00370
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 KU's responses to Tab Nos. 22-38.

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
Forecasted Income Statements 2016 - 2019
Base Period: Twelve Months Ended February 28, 2017
Forecasted Test Period: Twelve Months Ended June 30, 2018

Kentucky Utilities Company	**Income Statements**			
	2016	**2017**	**2018**	**2019**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Electric Operating Revenues	1,765,220,762	1,820,965,501	1,847,053,479	1,834,013,692
Total Operating Revenues	1,765,220,762	1,820,965,501	1,847,053,479	1,834,013,692
Operating Expenses				
Fuel for Electric Generation	501,704,848	518,293,951	507,786,765	504,276,586
Power Purchased	42,808,634	53,809,430	58,849,711	52,229,233
Other Operation Expenses	292,564,794	311,158,367	320,443,381	329,360,284
Maintenance	130,667,354	133,592,740	159,593,763	164,133,641
Depreciation & Amortization Expense	234,674,026	277,431,331	320,984,019	346,250,060
Regulatory Debits	178,816	962,769	3,497,958	9,072,737
Current Income Taxes	160,566,953	149,259,533	128,506,645	107,260,981
Property and Other Taxes	40,905,109	42,494,000	45,270,580	47,669,252
Investment Tax Credit	4,000,000			
Loss(Gain) from Disposition of Allowances	(92)			
Total Operating Expenses	1,408,070,444	1,487,002,121	1,544,932,821	1,560,252,774
Net Operating Income	357,150,318	333,963,380	302,120,658	273,760,918
AFUDC - Equity	320,941	-	-	-
Other Income less deductions	1,102,510	990,194	1,175,240	1,194,544
Income before Interest Charges	358,573,768	334,953,573	303,295,897	274,955,462
Interest Charges	95,352,664	95,897,417	97,095,812	102,640,804
Net Income	263,221,104	239,056,156	206,200,086	172,314,659

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
Balance Sheet - Total Company
Calendar Years 2016 - 2019

	2016	2017	2018	2019
Kentucky Utilities Company	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	9,377,187,354	9,844,041,457	10,370,533,279	10,733,716,682
Accumulated Provision for Depreciation and Amortization	(3,043,922,211)	(3,305,071,468)	(3,579,357,317)	(3,833,245,847)
Total Utility Net Plant	**6,333,265,143**	**6,538,969,989**	**6,791,175,962**	**6,900,470,836**
INVESTMENTS				
Investment in Subsidiary Companies				
Net Nonutility property	971,313	971,313	971,313	971,313
Other Investments	250,000	250,000	250,000	250,000
Total other Property and Investments	**1,221,313**	**1,221,313**	**1,221,313**	**1,221,313**
CURRENT AND ACCRUED ASSETS				
Cash	5,000,000	5,000,000	5,000,000	5,000,000
Special Deposits and Temporary Cash Investments	(0)	(0)	0	(0)
Accounts Receivable - Less Reserves	241,305,360	242,805,155	243,856,197	236,708,624
Accounts Receivable from Associated Companies	(133,217)	3,488,997	7,496,773	13,088,744
Inventories	157,655,660	136,479,027	132,918,188	133,849,976
Prepayments	16,282,753	16,781,354	17,450,440	18,328,442
Other Current and Accrued Assets				
Total Current and Accrued Assets	**420,110,555**	**404,554,533**	**406,721,598**	**406,975,785**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	28,476,070	26,344,650	24,006,332	23,182,469
Accumulated Deferred Income Tax Asset	351,912,941	351,912,941	351,912,941	351,912,941
Regulatory Assets	478,969,424	519,364,856	563,923,348	621,917,504
Miscellaneous Deferred Debits	54,032,228	52,870,222	59,546,505	45,995,695
Total Deferred Debits & Other	**913,390,662**	**950,492,669**	**999,389,126**	**1,043,008,609**
TOTAL ASSETS	**7,667,987,674**	**7,895,238,504**	**8,198,507,999**	**8,351,676,543**

Kentucky Utilities Company
Case No. 2016-00370
Balance Sheet - Total Company
Calendar Years 2016 - 2019

	2016	2017	2018	2019
Kentucky Utilities Company - Total	$	$	$	$
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	308,139,978	308,139,978	308,139,978	308,139,978
Common Stock Expense	(321,289)	(321,289)	(321,289)	(321,289)
Paid-in-capital	605,354,638	588,095,021	646,719,371	656,615,096
Retained Earnings	1,826,225,186	1,904,192,628	1,974,163,990	2,026,811,835
Other Comprehensive Income	(1,795,298)	(1,795,298)	(1,795,298)	(1,795,298)
Total Proprietary Capital	**2,737,603,215**	**2,798,311,041**	**2,926,906,752**	**2,989,450,323**
Total Long-Term Debt	**2,341,670,856**	**2,342,209,898**	**2,342,748,941**	**2,593,287,983**
TOTAL CAPITALIZATION	**5,079,274,071**	**5,140,520,939**	**5,269,655,692**	**5,582,738,306**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	83,690,630	140,336,505	252,425,694	58,832,085
Accounts Payable	82,473,971	80,566,613	79,766,454	78,636,267
Accounts Payable to Associated Companies	47,708,867	51,052,470	51,675,864	52,369,934
Customer Deposits	28,000,984	28,000,984	28,000,984	28,000,984
Taxes Accrued	6,408,034	6,461,353	6,545,282	6,608,621
Interest Accrued	15,979,080	14,534,902	14,538,083	15,245,277
Dividends Payable Affiliate				
Miscellaneous Current Liabilities	21,988,850	22,441,471	22,049,383	21,612,979
Total Current and Accrued Liabilities	**286,250,415**	**343,394,298**	**455,001,746**	**261,306,147**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	1,550,485,400	1,692,435,807	1,816,373,751	1,923,139,417
Investment Tax Credits	95,172,737	93,326,534	91,309,816	89,293,098
Regulatory Liabilities	147,919,987	142,005,753	138,827,935	136,156,388
Customer Advances for Construction	1,576,406	1,576,406	1,576,406	1,576,406
Asset Retirement Obligations	368,706,782	367,520,996	330,723,624	281,160,392
Other Deferred Credits	6,310,542	6,310,542	6,310,542	6,310,542
Miscellaneous Long Term Liabilities	2,343,040	2,343,040	2,343,040	2,343,040
Accumulated Provision for Post Retirement Benefits	129,948,295	105,804,191	86,385,448	67,652,808
Balancing Adjustment	-	-	-	-
Total Deferred Credits	**2,302,463,188**	**2,411,323,267**	**2,473,850,561**	**2,507,632,091**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**7,667,987,674**	**7,895,238,504**	**8,198,507,999**	**8,351,676,543**

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
Forecasted Cash Flow Statements 2016 - 2019
Base Period: Twelve Months Ended February 28, 2017
Forecasted Test Period: Twelve Months Ended June 30, 2018

Kentucky Utilities Company Cash Flow Statements	2016	2017	2018	2019
Cash Flows from Operating Activities				
Net Income	$ 263,221,104	$ 239,056,156	$ 206,200,086	$ 172,314,659
Items not requiring (providing) cash currently:				
Depreciation	234,707,955	277,431,331	320,984,019	346,250,060
Amortization	10,852,938	13,768,502	16,522,416	20,881,603
Deferred Income Taxes and Investment Tax Credits	154,015,465	138,766,153	120,464,066	103,798,058
Change in current assets and current liabilities:				
Change in Customer A/R	(35,601,056)	(5,122,009)	(5,058,819)	1,555,603
Change in Inventories	(9,399,845)	21,176,632	3,560,839	(931,788)
Change in Other Current Assets	(7,192,180)	339,081	(7,669,693)	12,348,484
Change in Regulatory Assets	(10,520,686)	(612,769)	1,189,484	(5,816,298)
Change in Accounts Payable	24,786,836	(278,620)	(1,422,364)	(1,060,583)
Change in Taxes Accrued	(14,086,086)	53,319	83,930	63,338
Change in Interest Accrued	285,154	(1,444,177)	3,181	707,194
Change in Other Current Liabilities	(83,984)	11,592,225	9,728,964	9,023,573
Other operating activities:				
ARO Expenditures	(10,638,595)	(17,491,920)	(51,419,038)	(62,379,204)
Pension Cash Payments	(22,050,382)	(25,797,910)	(20,263,208)	(18,908,469)
Other	1,171,243	-	-	-
Net Cash from Operating Activities	579,467,880	651,435,994	592,903,863	577,846,231
Cash Flows from Investing Activities				
Capital Expenditures for Property, Plant and Equipment	(416,128,342)	(529,733,538)	(627,388,678)	(522,467,859)
Net Cash from Investing Activities	(416,128,342)	(529,733,538)	(627,388,678)	(522,467,859)
Cash Flows from Financing Activities				
Issuance of Long-Term Debt	-	-	-	250,000,000
Net Increase (Decrease) in Short-Term Debt	35,693,158	56,645,875	112,089,189	(193,593,609)
Capital Contribution Received from Parent	41,496,555	-	58,624,350	9,895,725
Dividends on common stock	(246,299,105)	(178,348,331)	(136,228,724)	(119,666,813)
Cost of Issuing or Retiring Debt	(624,140)			(2,013,675)
Net Cash from Financing Activities	(169,733,532)	(121,702,455)	34,484,814	(55,378,372)
Net (Decrease) Increase in Cash and Cash Equivalents	(6,393,994)	-	-	-
Cash & Cash Equivalents - Beginning of Period	11,455,024	5,061,030	5,061,030	5,061,030
Cash & Cash Equivalents - End of Period	$ 5,061,030	$ 5,061,030	$ 5,061,030	$ 5,061,030

Note - The cash flow statements presented are at the Company level and not at a jurisdictional level.

Kentucky Utilities Company
Case No. 2016-00370
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.

KENTUCKY UTILITIES COMPANY
CASE NO. 2016-00370
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 KENTUCKY JURISDICTION (a)	3,533,494,351	3,613,861,313	3,685,637,892	4,101,596,097
2	ADJUSTED OPERATING INCOME	251,865,863	228,993,215	193,919,984	150,382,473
3	EARNED RATE OF RETURN (2 / 1)	7.13%	6.34%	5.26%	3.67%
4	REQUIRED RATE OF RETURN	7.34%	7.32%	7.26%	7.30%
5	REQUIRED OPERATING INCOME (1 x 4)	259,441,390	264,486,134	267,468,666	299,224,755
6	OPERATING INCOME DEFICIENCY (5 - 2)	7,575,527	35,492,919	73,548,682	148,842,282
7	GROSS REVENUE CONVERSION FACTOR	1.642132	1.642132	1.642132	1.642132
8	REVENUE DEFICIENCY (6 x 7)	12,440,017	58,284,065	120,776,659	244,418,705
9	ADJUSTED OPERATING REVENUES	1,477,618,530	1,485,913,920	1,489,717,167	1,494,147,223
10	REVENUE REQUIREMENTS (8 + 9)	1,490,058,547	1,544,197,985	1,610,493,827	1,738,565,928

(a) 13 months average
(b) Held constant for all periods. See Section 16(8)(h) Schedule H-1

Kentucky Utilities Company
Case No. 2016-00370
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

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:

KU Energy (GWh)

Rate	2016 *	2017	2018	2019
AES	143	152	152	151
FLS	568	553	553	553
GS	1,787	1,809	1,803	1,797
PS-Pri	157	169	170	171
PS-Sec	2,070	2,161	2,133	2,108
RS	5,989	6,087	6,096	6,110
RTS	1,447	1,484	1,496	1,492
TOD-Pri	4,063	4,108	4,127	4,142
TOD-Sec	1,679	1,664	1,678	1,691
Lighting	125	126	126	126
Total	18,027	18,314	18,333	18,341

*2016 includes 8 months of actual data and 4 months forecast

Kentucky Utilities Company
Case No. 2016-00370
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

KU Demand (Sum of Monthly Billing Demands)

Rate	SubRate	Unit	2016 *	2017	2018	2019
FLS	Base	MVA	2,307	2,292	2,292	2,292
	Intermediate	MVA	2,307	2,292	2,292	2,292
	Peak	MVA	1,645	1,625	1,625	1,625
PS-Pri	Base	MW	459	485	489	490
PS-Sec	Base	MW	6,168	6,213	6,247	6,247
RTS	Base	MVA	3,247	3,315	3,341	3,332
	Intermediate	MVA	3,190	3,262	3,287	3,278
	Peak	MVA	3,128	3,204	3,229	3,220
TOD-Pri	Base	MVA	9,756	9,626	9,484	9,512
	Intermediate	MVA	8,966	9,087	9,124	9,150
	Peak	MVA	8,824	8,959	8,995	9,021
TOD-Sec	Base	MW	4,371	4,402	4,525	4,471
	Intermediate	MW	3,953	3,995	4,115	4,059
	Peak	MW	3,858	3,892	4,011	3,954

*2016 includes 8 months of actual data and 4 months forecast

Kentucky Utilities Company
Case No. 2016-00370
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 KU's Application.

Kentucky Utilities Company
Case No. 2016-00370
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	231	148	144	164
Brown 2	435	371	361	399
Brown 3	988	888	871	857
Ghent 1	3,127	3,077	2,995	3,008
Ghent 2	3,092	2,901	3,046	2,614
Ghent 3	2,680	2,892	2,577	2,826
Ghent 4	3,117	3,023	2,932	2,848
Mill Creek 1	N/A	N/A	N/A	N/A
Mill Creek 2	N/A	N/A	N/A	N/A
Mill Creek 3	N/A	N/A	N/A	N/A
Mill Creek 4	N/A	N/A	N/A	N/A
OVEC	253	216	195	194
Trimble County 1	N/A	N/A	N/A	N/A
Trimble County 2	2,323	2,883	2,737	3,005
SCCT				
Bluegrass/EKPC[3]	N/A	N/A	N/A	N/A
Brown 5	31	12	22	10
Brown 6	17	35	40	34
Brown 7	15	43	58	49
Brown 8	103	15	18	9
Brown 9	110	9	11	7
Brown 10	120	6	10	7
Brown 11	71	9	11	8
Cane Run 11	N/A	N/A	N/A	N/A
Haefling	0	0	0	0
Paddys Run 11	N/A	N/A	N/A	N/A
Paddys Run 12	N/A	N/A	N/A	N/A
Paddys Run 13	54	91	88	77
Trimble Co 05	217	226	293	220
Trimble Co 06	143	218	242	190
Trimble Co 07	165	144	144	142
Trimble Co 08	41	38	53	38
Trimble Co 09	122	104	134	88
Trimble Co 10	53	22	28	21
Zorn 1	N/A	N/A	N/A	N/A
NGCC				
Cane Run 7	3,854	3,820	3,854	3,490
Hydro				
Dix Dam	91	76	76	76
Ohio Falls	N/A	N/A	N/A	N/A
Solar				
Brown Solar	8	12	12	12
Total Coal	16,246	16,399	15,857	15,916
Total SCCT	1,263	971	1,150	900
Total NGCC	3,854	3,820	3,854	3,490
Total Hydro	91	76	76	76
Total Solar	8	12	12	12
Grand Total	21,461	21,279	20,949	20,394

[1] Generation volumes reflect KU's ownership share of the unit. "N/A" is shown for units with no KU 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

Kentucky Utilities Company
Case No. 2016-00370
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: 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:

8. Mix of gas supply (gas);

Response:

Not applicable to KU’s Application.

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company
Case No. 2016-00370
Employee Level
Years 2016-2019

	Estimated Number of Full-Time KU Employees at 12/31
2016	931
2017	936
2018	939
2019	935

	Estimated Number of Total KU Employees at 12/31 [A]
2016	948
2017	947
2018	948
2019	944

	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.

Kentucky Utilities Company
Case No. 2016-00370
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

<u>Description of Filing Requirement:</u>

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;

<u>Response:</u>

See attached.

Kentucky Utilities Company
Case No. 2016-00370
Labor Cost
Years 2016-2019

Forecast Year	Total Wages	Amount Over Previous Year	Percentage Over Previous Year
2016	$ 187,499,733		
2017	$ 191,449,567	$ 3,949,834	2.11%
2018	$ 197,075,755	$ 5,626,188	2.94%
2019	$ 201,468,251	$ 4,392,496	2.23%

Kentucky Utilities Company
Case No. 2016-00370
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.

KENTUCKY UTILITIES COMPANY
CASE NO. 2016-00370
CAPITAL STRUCTURE REQUIREMENT
AS OF DECEMBER 31

		FORECASTED							
		2016		2017		2018		2019	
LINE NO.	CLASS OF CAPITAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		$		$		$		$	
1	SHORT-TERM DEBT	59,157,069	1.63%	97,605,645	2.67%	174,368,326	4.59%	43,729,187	1.05%
2	LONG-TERM DEBT	1,635,091,326	45.06%	1,610,710,779	44.08%	1,601,719,942	42.18%	1,910,328,764	45.75%
3	COMMON EQUITY	1,934,729,798	53.31%	1,945,906,682	53.25%	2,021,473,769	53.23%	2,221,648,010	53.20%
4	TOTAL CAPITAL	3,628,978,192	100.00%	3,654,223,106	100.00%	3,797,562,038	100.00%	4,175,705,961	100.00%

Kentucky Utilities Company
Case No. 2016-00370
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.

Kentucky Utilities Company

Case No. 2016-00370

Net Original Cost Kentucky Jurisdictional Rate Base as of December 31,

	FORECASTED			
	2016	2017	2018	2019
Title of Account (1)	Kentucky Jurisdictional Pro Forma Base Rate Base (2)	Kentucky Jurisdictional Pro Forma Base Rate Base (3)	Kentucky Jurisdictional Pro Forma Base Rate Base (4)	Kentucky Jurisdictional Pro Forma Base Rate Base (5)
1. Utility Plant at Original Cost	$ 6,799,061,885	$ 7,081,611,183	$ 7,398,135,887	$ 8,138,455,188
2. Deduct:				
3. Reserve for Depreciation	2,549,489,654	2,701,230,647	2,853,096,543	3,136,187,787
4. Net Utility Plant	4,249,572,231	4,380,380,536	4,545,039,344	5,002,267,401
5. Deduct:				
6. Customer Advances for Construction	1,549,704	1,549,704	1,549,704	1,549,704
7. Accumulated Deferred Income Taxes	822,743,338	921,500,358	961,702,388	1,062,503,246
8. Investment Tax Credit	82,806,055	81,199,747	79,450,595	83,021,571
9. Total Deductions	907,099,097	1,004,249,808	1,042,702,687	1,147,074,521
10. Net Plant Deductions	3,342,473,135	3,376,130,729	3,502,336,657	3,855,192,880
11. Add:				
12. Materials and Supplies	136,270,999	126,191,774	117,442,865	124,574,226
13. Prepayments	12,669,287	16,096,054	17,117,301	18,605,685
14. Emission Allowances	0	(0)	-	-
15. Cash Working Capital (page 2)	100,154,542	104,562,443	107,281,349	113,663,471
16. Total Additions	249,094,828	246,850,271	241,841,516	256,843,382
17. Total Net Original Cost Rate Base	$ 3,591,567,963	$ 3,622,981,000	$ 3,744,178,173	$ 4,112,036,262

KENTUCKY UTILITIES

Calculation of Cash Working Capital
As of December 31

	FORECASTED			
	2016	2017	2018	2019
Title of Account (1)	Kentucky Jurisdictional Pro Forma Base Rate Base (2)	Kentucky Jurisdictional Pro Forma Base Rate Base (3)	Kentucky Jurisdictional Pro Forma Base Rate Base (4)	Kentucky Jurisdictional Pro Forma Base Rate Base (5)
1. Operating and maintenance expense for the 12 months ended December 31,	$ 838,854,994	$ 883,785,302	$ 909,971,525	$ 958,374,589
2. Deduct:				
3. Electric Power Purchased	37,618,661	47,285,758	51,720,727	49,066,817
4. Total Deductions	$ 37,618,661	$ 47,285,758	$ 51,720,727	$ 49,066,817
5. Remainder (Line 1 - Line 4)	$ 801,236,333	$ 836,499,543	$ 858,250,798	$ 909,307,772
6. Cash Working Capital	$ 100,154,542	$ 104,562,443	$ 107,281,350	$ 113,663,472

Kentucky Jurisdictional (12 1/2% of Line 5)

Kentucky Utilities Company
Case No. 2016-00370
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 KU's Application.

Kentucky Utilities Company
Case No. 2016-00370
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:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2016-00370
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:

Not applicable to KU’s Application.

Kentucky Utilities Company
Case No. 2016-00370
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 KU's Application.

Kentucky Utilities Company
Case No. 2016-00370
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 KU's Application.

Kentucky Utilities Company
Case No. 2016-00370
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 KU is attached. The Federal Communications Commission has not conducted an audit of KU, 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.

Vincent Sorgi
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http://www.pplweb.com/

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.

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.

Kentucky Utilities Company
Case No. 2016-00370
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 not 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.

$96,000,000
COUNTY OF CARROLL, KENTUCKY
Pollution Control Revenue Refunding Bonds
2016 Series A
(Kentucky Utilities Company Project)

Dated: Date of original delivery	**Due:** September 1, 2042
Long Term Rate Period: 3 years	**Mandatory Purchase Date:** September 1, 2019
Interest Payment Dates: March 1 and September 1	**Interest Rate:** 1.05%

The County of Carroll, Kentucky, Pollution Control Revenue Refunding Bonds, 2016 Series A (Kentucky Utilities Company Project) (the "Bonds") will be special and limited obligations of the County of Carroll, 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 Kentucky Utilities 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

KENTUCKY UTILITIES COMPANY

From and after the date of the issuance and delivery of the Bonds, the Bonds will bear interest at the Long Term Rate of 1.05% per annum from the date of issuance to and including August 31, 2019, and will be subject to mandatory purchase following the initial Long Term Rate Period on September 1, 2019 (the "Mandatory Purchase Date"). Interest on the Bonds will be payable on each March 1 and September 1, commencing March 1, 2017. The interest rate period, interest rate and interest rate mode will be subject to change under certain conditions, as described in this Official Statement. Prior to the Mandatory Purchase Date, the Bonds will not be subject to optional redemption, but will be subject to extraordinary optional redemption and mandatory redemption following a determination of taxability prior to maturity, 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 $250,000 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.

The Bonds are offered when, as and if issued and received by the Underwriters, 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 Underwriters by their 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 August 25, 2016.

BofA Merrill Lynch **PNC Capital Markets LLC**

Dated: August 17, 2016

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Underwriters 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 Underwriters have provided the following sentence for inclusion in this Official Statement. The Underwriters have reviewed the information in this Official Statement in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do 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 Underwriters 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

$96,000,000
County of Carroll, Kentucky
Pollution Control Revenue Refunding Bonds
2016 Series A
(Kentucky Utilities 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 Carroll, Kentucky (the "Issuer") of its Pollution Control Revenue Refunding Bonds, 2016 Series A (Kentucky Utilities Company Project), in the aggregate principal amount of $96,000,000 (the "Bonds") to be issued pursuant to an Indenture of Trust dated as of August 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 Kentucky Utilities Company (the "Company") and the Issuer, dated as of August 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 all of the $96,000,000 outstanding principal amount of County of Carroll, Kentucky, Pollution Control Revenue Bonds, 2002 Series C (Kentucky Utilities Company Project) (the "2002 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 Underwriters' obligation to purchase the Bonds that the Company irrevocably instruct the trustee in respect of the 2002 Bonds, on or prior to the date of issuance of the Bonds, to call the 2002 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 2016CCA (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 August 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.

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 Underwriters. The First Mortgage Indenture (including the form of the First Mortgage Bonds) is available for inspection at the office of the Company in Lexington, 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 Underwriters have reviewed the information in Appendix A to this Official Statement in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do 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 Long Term Rate for the initial Long Term Rate Period. In the event of a remarketing of the Bonds on or after the Mandatory Purchase Date, 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 2002 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, solid waste and water pollution control facilities at the Company's Ghent Generating Station located in Carroll County, Kentucky (the "Generating Station").

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 2002 Bonds, on the date of the issuance of the Bonds. The 2002 Bonds currently bear interest at an auction rate and mature on October 1, 2032. For the twelve months ended June 30, 2016, the weighted average interest rate on the 2002 Bonds was 0.526%.

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, 2042. The Bonds are also subject to redemption prior to maturity as described in this Official Statement.

The Bonds will bear interest at the Long Term Rate of 1.05% per annum from August 25, 2016 to and including August 31, 2019, and will be subject to mandatory purchase following the initial Long Term Rate Period on September 1, 2019 (the "Mandatory Purchase Date"). Interest on the Bonds will be paid on each March 1 and September 1, commencing March 1, 2017. The Bonds will continue to bear interest at a Long Term Rate for periods to be determined by the Company until a Conversion to another Interest Rate Mode or until the maturity or redemption 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 Long Term Rate for the initial Long Term Rate Period. In the event of a remarketing of the Bonds on or after the Mandatory Purchase Date, 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.

Interest on the Bonds will be computed on the basis of a 360-day year, consisting of twelve 30-day months. Interest payable on each March 1 and September 1 will be payable to the registered owner of the Bond as of the February 15 and August 15 preceding such March 1 and September 1.

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 $250,000 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) which has been purchased (see "Mandatory Purchase 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 or the establishment of a new Long Term Rate Period.

"*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.

"*Long Term Rate Period*" means the period beginning on, and including, the date of issuance of the Bonds and ending on, and including, August 31, 2019 and, thereafter, the period established by the Company under the Indenture and beginning on September 1, 2019 and ending on the day preceding the last Interest Payment Date for such period and, thereafter, each successive period of the same duration until the day immediately preceding the earliest of the change to a different Long Term Rate Period, the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Remarketing Agent*" means Merrill Lynch, Pierce, Fenner & Smith Incorporated and its successor or successors, who will act as the Remarketing Agent with respect to 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 to be entered into between the Remarketing Agent and the Company (the "Remarketing Agreement"). The Remarketing Agent may, without notice to the Company, assign its rights and obligations as Remarketing Agent to a broker-dealer affiliate in accordance with the terms of the Indenture and the Remarketing Agreement.

"*Tender Agent*" means, so long as the Bonds are held in DTC's book-entry-only system, the Trustee, who will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Mandatory Purchase of Bonds

General. The Bonds will be subject to mandatory purchase on the Mandatory Purchase Date at a purchase price equal to the principal amount thereof plus accrued and unpaid interest. Notice to owners of such mandatory purchase will be given by the Bond Registrar by first class mail at least 20 days prior the Mandatory Purchase 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, unless otherwise instructed by the Company, the Remarketing Agent will use its commercially reasonable best efforts to remarket Bonds purchased on the Mandatory Purchase Date. 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 on the Mandatory Purchase Date upon delivery of such Bond to the Tender Agent on such Mandatory Purchase Date; provided that such Bond must be delivered to the Tender Agent at or prior to 11:00 a.m. (New York City time). 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. If the Mandatory Purchase Date is not a Business Day, the purchase price will be payable on the next succeeding Business Day.

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 Mandatory 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 Mandatory Purchase Date. Any owner who so fails to deliver such Bond for purchase on (or before) the Mandatory 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.

Redemptions

Optional Redemption. Except as described below under the subheadings "— Extraordinary Optional Redemption in Whole" and "— Extraordinary Optional Redemption in Whole or in Part," the Bonds are not subject to optional redemption prior to the Mandatory Purchase Date.

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 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;

(ii) 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;

(iii) 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

(iv) 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.

As a result of a Company Letter Agreement between the Issuer and the Company, to be dated as of August 25, 2016, the Company will agree that it will not, prior to September 1, 2019, exercise the rights under the Loan Agreement it would otherwise have to redeem the Bonds under the following circumstances:

(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; or

(ii) 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 the Generating Station or any generating unit at the Generating Station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in clean air or water 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.

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."

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 20 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.

Conversion of Interest Rate Modes

The Interest Rate Mode for the Bonds is subject to Conversion from time to time, including on the Mandatory Purchase Date following the end of the initial Long Term Rate Period, at the option of the Company in accordance with the terms of the Indenture, upon notice from the Bond Registrar to the registered owners of the Bonds. 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.

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 Underwriters 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 shall effect delivery of purchased 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 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 Underwriters 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 UNDERWRITERS, 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 $250,000 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 "— Mandatory Purchase 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, 2042 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 (i) 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, (ii) the expenses in connection with any redemption of the Bonds and (iii) 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 — Mandatory Purchase 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 and solid waste disposal facilities, as applicable, under Section 103(b)(4)(E) and (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)(E) and (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 Commonwealths of Kentucky and Virginia, 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:

(i) 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;

(ii) 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 (i) 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;

(iii) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(iv) the occurrence of an Event of Default under the Indenture; or

(v) 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 be 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 has 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 — Extraordinary Optional Redemption in Whole" and "— Extraordinary Optional Redemption in Whole or in Part." Upon the occurrence of the event described under the heading "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 amonnt 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 whicb interest on the Bonds bas 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 (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; 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; 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 $2,350,779,405 were outstanding under the First Mortgage Indenture, of which $350,779,405 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 $1.8 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 sucb 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 he 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 2002 Bond Fund

The proceeds from the issuance of the Bonds will be deposited by the Trustee in the County of Carroll, Kentucky, Pollution Control Revenue Bond Fund, 2002 Series C (Kentucky Utilities Company Project) created by the Indenture of Trust dated as of July 1, 2002 for the 2002 Bonds in an amount adequate to pay, together with other moneys to be provided by the Company, all principal of and accrued interest on the related issue of the 2002 Bonds to become due and payable on their scheduled redemption date.

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:

(i) failure to make due and punctual payment of any installment of interest on any Bond within a period of five Business Days from the due date;

(ii) 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 — Mandatory Purchase of Bonds — Remarketing and Purchase of Bonds" above;

(iii) failure by 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;

(iv) the occurrence of an "Event of Default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default"); or

(v) 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 (v) 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 (i) 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 and (ii) will not 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 2002 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 2002 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 2002 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 2002 Bonds directing the redemption of the 2002 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:

(i) Provisions of the Code applicable to corporations (as defined for federal income tax purposes) which impose an alternative minimum tax on a portion of the excess of adjusted current earnings over other alternative minimum taxable income may subject a portion of the interest on the Bonds earned by certain corporations to such corporate alternative minimum tax. Such corporate alternative minimum tax does not apply to any S corporation, regulated investment company, real estate investment trust or REMIC.

(ii) 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.

(iii) 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 Underwriters by their counsel, McGuireWoods LLP, Chicago, Illinois.

Underwriting

Merrill Lynch, Pierce, Fenner & Smith Incorporated and PNC Capital Markets LLC (the "Underwriters") have agreed, subject to the terms of the bond purchase agreement between the Issuer and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the Underwriters, to purchase the Bonds from the Issuer at the public offering price set forth on the cover page of this Official Statement. The Underwriters are committed to purchase all the Bonds if any Bonds are purchased. In connection with the underwriting of the Bonds, the Underwriters will be paid by the Company a fee in the amount of $312,000, which excludes reimbursement for certain reasonable out-of-pocket expenses.

The Underwriters 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 Underwriters.

In connection with the offering of the Bonds, the Underwriters 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 Underwriters and the Issuer against certain civil liabilities, including liabilities under the federal securities laws, or contribute to payments that the Underwriters or the Issuer may be required to make in respect thereof.

In the ordinary course of its business, the Underwriters and certain of their affiliates have in the past and may in the future engage in investment and commercial banking transactions with the Company, including the provision of certain advisory services to the Company.

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 Underwriters 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; (h) 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 by 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 6 series of pollution control bonds. The MSRB's Electronic Municipal Market Access website reflects that within the past five years the Company did not timely file certain information in connection with a December 2014 downgrade of credit ratings for four series of Company pollution control bonds resulting from the downgrade of the bank providing the letters of credit supporting such bonds. Moody's Investors Service, Inc. downgraded the long-term rating of the four Company pollution control bonds on December 2, 2014. The Company was not aware of the downgrade until February 10, 2015 and filed the required disclosures on February 11, 2015. 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 CARROLL, KENTUCKY

By: /s/ Bobby Lee Westrick
County Judge/Executive

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Appendix A

Kentucky Utilities Company

Kentucky Utilities Company ("KU"), incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of December 31, 2015, KU provided electricity to approximately 518,000 customers in 77 counties in central, southeastern and western Kentucky, approximately 28,000 customers in five counties in southwestern Virginia and fewer than 10 customers in Tennessee. KU's service area covers approximately 4,800 non-contiguous square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by natural gas fueled combined cycle combustion turbines, a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 11 municipalities.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. KU's affiliate, Louisville Gas and Electric Company ("LG&E"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and natural gas in Kentucky. KU's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of LG&E, PPL Corporation or KU's other affiliates will be obligated to make any payment on the Loan Agreement or the Bonds.

The information above concerning KU is only a summary and does not purport to be comprehensive. Additional information regarding KU, 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	$ 860	$ 881	$ 1,728	$ 1,737	$ 1,635
Operating income	$ 257	$ 225	$ 455	$ 433	$ 433
Net income	$ 129	$ 117	$ 234	$ 220	$ 228
Total assets[1]	$ 8,070	$ 7,853	$ 8,011	$ 7,701	$ 7,147
Long-term debt obligations (including amounts due within one year)[1]	$2,327	$ 2,080	$ 2,326	$ 2,079	$ 2,078
Ratio of earnings to fixed charges[2]	5.3	5.7	5.3	5.4	5.9

Capitalization:

	June 30, 2016	% of Capitalization
Long-term debt and notes payable	$ 2,356	41%
Common equity	3,322	59%
Total capitalization	$ 5,678	100%

(1) Effective December 31, 2015, KU 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 $11 million and $13 million, respectively.

Additionally, effective October 1, 2015, KU 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 $20 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 KU'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 KU or that KU currently deems immaterial may also impair its business operations, its financial results and the value of the Bonds.

Available Information

KU 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, DC 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 KU with the SEC, are incorporated herein by reference:

1. Form 10-K Annual Report of KU for the year ended December 31, 2015;

2. Form 10-Q Quarterly Reports of KU for the quarters ended March 31, 2016 and June 30, 2016; and

3. Form 8-K Current Reports of KU filed with the SEC on January 12, 2016, February 3, 2016 and June 17, 2016.

All documents filed by KU 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.

KU 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, Kentucky Utilities Company, One Quality Street, Lexington, Kentucky 40507, telephone: (859) 255-2100.

Appendix B

(Form of Opinion of Bond Counsel)

August___, 2016

Re: $96,000,000 County of Carroll, Kentucky, Pollution Control Revenue Refunding Bonds, 2016 Series A (Kentucky Utilities Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, 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 (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $96,000,000 (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 Kentucky Utilities Company (the "**Company**") for the current refunding of $96,000,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 2002 Series C (Kentucky Utilities Company Project), dated October 3, 2002 (the "**Refunded 2002 Series C Bonds**"), which were issued for the purpose of currently refunding a portion of the costs of construction of air and water pollution control facilities and solid waste disposal facilities serving certain electric generating units of the Company located in Carroll County, Kentucky (the "**Project**"), as provided by the Act.

The 2016 Series A Bonds mature on September 1, 2042 and bear interest initially at the Long Term 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 August 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 2002 Series C 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 August 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 not 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 and solid waste disposal facilities qualified for financing under Section 103(b)(4)(E) and (F) of the Internal Revenue Code of 1954, as amended, and Section 1313(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) Provisions of the Code applicable to corporations (as defined for federal income tax purposes) which impose an alternative minimum tax on a portion of the excess of adjusted current earnings over other alternative minimum taxable income may subject a portion of the interest on the 2016 Series A Bonds earned by certain corporations to such corporate alternative minimum tax. Such corporate alternative minimum tax does not apply to any S corporation, regulated investment company, real estate investment trust, or REMIC.

(b) 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.

(c) 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. Nicholas Marsh, County Attorney of Carroll 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

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Kentucky Utilities Company
Case No. 2016-00370
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:

See attached.

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

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**
Kentucky Utilities Company	**End of** 2015/Q4

FERC FORM No.1/3-Q (REV. 02-04)

KENTUCKY UTILITIES 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.

KENTUCKY UTILITIES 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)	32,598
Total number of Miles of Pole line (Located in Kentucky)	20,536

Name of Counties in which you furnish Electric Service:
(If additional space is required, add additional sheet)

Adair	Campbell	Fayette	Harrison	Lincoln	McLean	Russell
Anderson	Carlisle	Fleming	Hart	Livington	Nelson	Scott
Ballard	Carroll	Franklin	Henderson	Lyon	Nicholas	Shelby
Barren	Casey	Fulton	Henry	Madison	Ohio	Spencer
Bath	Christian	Gallatin	Hickman	Marion	Oldham	Taylor
Bell	Clark	Garrard	Hopkins	Mason	Owen	Trimble
Bourbon	Clay	Grant	Jessamine	Mercer	Pendleton	Union
Boyle	Crittenden	Grayson	Knox	Montgomery	Pulaski	Washington
Bracken	Daviess	Green	Larue	Muhlenberg	Robertson	Webster
Bullitt	Edmonson	Hardin	Laurel	McCracken	Rockcastle	Whitley
Caldwell	Estill	Harlan	Lee	McCreary	Rowan	Woodford

Kentucky Utilities Company
Supplemental Electric Information
Revenues, Customers and KWH Sales
For Reporting Year 2015

	Revenues	KWHs Sold	Customers
440 Residential	$ 576,210,558	5,995,217,738	423,953
442 Commercial & Industrial Sales			
Small (or Commercial)	$ 361,977,363	3,802,669,897	80,162
Large (or Industrial)	$ 418,748,749	6,883,841,474	2,969
444 Public Street & Highway Lighting	$ 11,294,624	41,840,116	1,446
445 Other Sales to Public Authorities	$ 121,799,758	1,555,854,887	7,423
446 Sales to Railroads and Railways	$ -	-	-
448 Interdepartmental Sales	$ -	-	-
TOTAL Sales to Ultimate Customers	$ 1,490,031,052	18,279,424,112	515,953
447 Sales for Resale	$ 143,406,275	2,763,736,400	23
449 Provision for Rate Refund - FERC Municiple Rates	$ (3,840,132)		
TOTAL Sales of Electricity	$ 1,629,597,195	21,043,160,512	515,976

THIS PAGE MUST BE COMPLETED AND RETURNED WITH THE ANNUAL REPORT

**** For Kentucky Operations Only**

KENTUCKY UTILITIES 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.

3. 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	926
3.	Total Part-Time and Temporary Employee	14
4.	Total Employees	940

Additional Requested Information

Utility Name Kentucky Utilities Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	4	7	5	7	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**
Kentucky Utilities Company	**End of** 2015/Q4

FERC FORM No.1/3-Q (REV. 02-04)

EY
Building a better working world

Ernst & Young LLP
Suite 2400
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 Kentucky Utilities Company:

We have audited the accompanying financial statements of Kentucky Utilities 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 123.59 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 Kentucky Utilities 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 Kentucky Utilities 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 Kentucky Utilities 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)* One Quality Street, Lexington, KY 40507		
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) ☒ 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	03 Signature Kent W. Blake	04 Date Signed *(Mo, Da, Yr)* 03/23/2016
02 Title Chief Financial Officer		

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
Kentucky Utilities 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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	None
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
Kentucky Utilities 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	None
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 Kentucky Utilities 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 August 17, 1912
Virginia December 1, 1991

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 services in Kentucky, Tennessee and Virginia.

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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 beneficieries for whom trust was maintained, and purpose of the trust.

Kentucky Utilities Company (KU) 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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 (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	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 KU.

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
Kentucky Utilities 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	S. Bradford Rives, Chief Administrative Officer	220 West Main Street, Louisville, KY 40202
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	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.: 13 Column: a

S. Bradford Rives, Chief Administrative Officer, announced his retirement, effective March 13, 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Various	Docket No. ER13-2428
2		
3	Open Access Transmission Tariff (OATT)	
4	Attachment O	Docket No. ER11-2955
5		
6	OATT Schedule 1	Docket No. ER10-1509
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Name of Respondent Kentucky Utilities 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: 106 Line No.: 1 Column: a

Municipal	Rate Schedule No. for Amended Agreement as filed 2/1/2016
Barbourville	184 3.0.0
Bardstown	185 3.0.0
Bardwell	186 3.0.0
Berea	197 3.0.0
Corbin	188 3.0.0
Falmouth	189 3.0.0
Frankfort	190 3.0.0
Madisonville	161 3.0.0
Nicholasville	157 3.0.0
Paris (1)	83 3.0.0
Paris (1)	407 3.0.0
Providence	195 3.0.0

(1) Paris is in FERC litigation with the Company and final Orders are pending.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)?

[X] Yes
[ ] 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
1	20150501-5364	05/01/2015	ER13-2428	Annual Update to Generation	Various
2				Formula Rates	
3					
4	20150807-5188	08/07/2015	ER13-2428	Formula Revisions were	
5				filed 08/07/2015	
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 1061 Line No.: 1 Column: d

In September 2013, KU filed an application with the FERC to adjust the formula rate under which KU provides wholesale requirements power sales to 12 municipal customers. Among other changes, the application requested an amended formula whereby KU would charge cost-based rates with a subsequent true-up. KU's application proposed an authorized return on equity of 10.7%. Certain elements, including the new formula rate, became effective April 23, 2014, subject to refund. In April 2014, nine municipalities submitted notices of termination, under the original notice period provisions, to cease taking power under the wholesale requirements contracts. Such termination to be effective in 2019, except in the case of one municipality with a 2017 effective date. In addition, a tenth municipality has become a transmission only customer as of June 2015. In July 2014, KU agreed on settlement terms with the two municipal customers that did not provide termination notices and filed the settlement proposal with the FERC for its approval. In August 2014, the FERC issued an order on the interim settlement agreement allowing the proposed rates to become effective pending a final order. During the fourth quarter of 2015, the FERC approved the settlement agreement resolving the rate case with respect to these two municipalities, including approval of the formula rate with a true-up provision and authorizing a return on equity of 10% or the return on equity awarded to the other parties in this case, whichever is lower. In August 2015, KU filed a partial settlement agreement with the nine terminating municipalities, which was approved by FERC in the fourth quarter of 2015 resolving all but one open matter with one municipality, including providing for certain refunds, approving the formula rate with a true-up provision, and authorizing a 10.25% return on equity. Refunds to both the remaining municipals and the departing municipals were issued during the fourth quarter of 2015 totalling $3.4 million. A single remaining unresolved issue with one terminating municipality is in FERC litigation proceedings. Hearings on the dispute were conducted in January 2016. KU cannot predict the ultimate outcome of the remaining FERC proceeding regarding its wholesale power agreement with the remaining municipality, but the amounts under continuing dispute are not estimated to be significant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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				
3				
4	Page 2 of 5	Schedule 10	3	2
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6	Page 3 of 5	Schedule 10	3	1
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

FOOTNOTE DATA

Schedule Page: 1062 Line No.: 4 Column: b

Transmission Gross Plant in Service excludes certain Virginia assets in compliance with FERC Order in Docket No. ER02-2560.

Schedule Page: 1062 Line No.: 6 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
Kentucky Utilities 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 Kentucky Utilities 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, KU and LG&E 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 KU and LG&E. The early termination and repurchase transaction occurred pursuant to provisions in such lease. KU and LG&E 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 KU.

4. None of a material nature.

5. None.

6. KU received FERC authorization in FERC Docket No. ES13-68-000 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. KU's money pool balance was zero at December 31, 2015, and December 31, 2014. KU'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 $48 million and $236 million, respectively.

   KU has a letter of credit facility totaling $198 million. The facility is consistent with the above FERC authorization and was approved by Kentucky Public Service Commission Order in Case No. 2008-00309 on September 16, 2008, by the Virginia State Corporation Commission on August 29, 2008, in Case No. PUE-2008-00077, and by the Tennessee Regulatory Authority on September 15, 2008, in Docket No. 08-00144. Letters of credit totaling $198 million were outstanding under this facility at December 31, 2015, and December 31, 2014.

   On September 28, 2015, KU issued $500 million of first mortgage bonds of which $250 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. 2014-00082 dated June 16, 2014, and amended June 30, 2014, Virginia State Corporation Commission Order in Case No. PUE-2014-00031 dated May 8, 2014, and Tennessee Regulatory Authority Order in Case No. 2014-00033 dated June 24, 2014.

   KU has a revolving credit facility totaling $400 million. The facility was approved by the Kentucky Public Service Commission Order, Case No. 2010-00206 on September 30, 2010, by the Virginia State Corporation Commission on October 19, 2010, in Case No. PUE-2010-00061, and by the Tennessee Regulatory Authority on October 21, 2010, in Docket No. 10-00119. There were no borrowings outstanding under this facility at December 31, 2015, and December 31, 2014. On January 29, 2016, KU 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. 2015-00137 on July 2, 2015, by the Virginia State Corporation Commission on June 18, 2015, in Case No. PUE-2014-00031, and by the Tennessee Regulatory Authority on August 3, 2015, in Docket

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

No. 15-00056.

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 USW Local 09447-01 and IBEW Local 2100 contracts, union employees received a negotiated wage increase of 2.5% effective July 26, 2015. Additionally, the KU hourly employees received an annual increase of 2.5% effective July 26, 2015.

9. See Notes 4 and 10 of Notes to Financial Statements on page 123.

10. None.

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. KU 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
Kentucky Utilities Company	(1) [X] 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	8,814,981,934	7,787,639,370
3	Construction Work in Progress (107)	200-201	267,026,968	880,068,809
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,082,008,902	8,667,708,179
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,849,851,989	2,798,968,737
6	Net Utility Plant (Enter Total of line 4 less 5)		6,232,156,913	5,868,739,442
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)		6,232,156,913	5,868,739,442
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		971,313	971,313
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	250,000	250,000
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)		0	0
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)		1,221,313	1,221,313
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,140,987	7,008,866
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		61,030	61,030
38	Temporary Cash Investments (136)		4,253,006	4,066,766
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		118,748,901	126,706,511
41	Other Accounts Receivable (143)		7,890,513	5,608,374
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,832,010	2,417,633
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		847,986	59,765,613
45	Fuel Stock (151)	227	97,051,051	99,282,056
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	41,183,222	38,655,516
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	140,356	158,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	9,371,630	10,574,016
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		7,513,311	7,629,374
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		41,430	9,979
60	Rents Receivable (172)		763,971	1,294,701
61	Accrued Utility Revenues (173)		80,083,721	91,068,107
62	Miscellaneous Current and Accrued Assets (174)		0	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)		373,259,105	449,472,148
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,557,911	15,052,789
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	382,517,903	333,252,432
73	Prelim. Survey and Investigation Charges (Electric) (183)		6,761,703	5,723,428
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	685,725,650	710,049,311
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	46,995	0
81	Unamortized Loss on Reaquired Debt (189)		8,907,228	9,590,735
82	Accumulated Deferred Income Taxes (190)	234	372,714,647	246,753,190
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,474,232,037	1,320,421,885
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,080,869,368	7,639,854,788

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

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Unamortized Debt Expenses (181) Without Purchase Accounting	$	20,924,669
Purchase Accounting Adjustment		(3,366,758)
Total for Unamortized Debt Expenses (181)	$	17,557,911

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Unamortized Debt Expenses (181) Without Purchase Accounting	$	18,614,827
Purchase Accounting Adjustment		(3,562,038)
Total for Unamortized Debt Expenses (181)	$	15,052,789

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Other Regulatory Assets (182.3) Without Purchase Accounting	$	379,151,145
Purchase Accounting Adjustment		3,366,758
Total for Other Regulatory Assets (182.3)	$	382,517,903

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Other Regulatory Assets (182.3) Without Purchase Accounting	$	329,468,702
Purchase Accounting Adjustment		3,783,730
Total for Other Regulatory Assets (182.3)	$	333,252,432

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Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	40,963,313
Purchase Accounting Adjustment		644,762,337
Total for Miscellaneous Deferred Debits (186)	$	685,725,650

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Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	38,961,965
Purchase Accounting Adjustment		671,087,346
Total for Miscellaneous Deferred Debits (186)	$	710,049,311

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Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	358,038,656
Purchase Accounting Adjustment		14,675,991
Total for Accumulated Deferred Income Taxes (190)	$	372,714,647

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Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	221,690,913
Purchase Accounting Adjustment		25,062,277
Total for Accumulated Deferred Income Taxes (190)	$	246,753,190

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	308,139,978	308,139,978
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	2,596,446,834	2,596,446,834
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	321,289	321,289
11	Retained Earnings (215, 215.1, 216)	118-119	382,553,214	302,016,562
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)	-287,400	233,308
16	Total Proprietary Capital (lines 2 through 15)		3,286,531,337	3,206,515,393
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,350,779,405	2,100,779,405
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	369,516	522,778
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		9,648,803	10,011,254
24	Total Long-Term Debt (lines 18 through 23)		2,341,500,118	2,091,290,929
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)		2,343,040	2,049,992
29	Accumulated Provision for Pensions and Benefits (228.3)		93,702,289	117,607,470
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		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		362,143,424	210,966,864
35	Total Other Noncurrent Liabilities (lines 26 through 34)		458,188,753	330,624,326
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		47,997,120	235,592,322
38	Accounts Payable (232)		108,362,454	153,042,158
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		39,179,664	46,590,075
41	Customer Deposits (235)		26,249,503	27,255,893
42	Taxes Accrued (236)	262-263	20,427,557	13,974,039
43	Interest Accrued (237)		15,760,841	11,624,315
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
Kentucky Utilities 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)		3,989,313	5,223,518
48	Miscellaneous Current and Accrued Liabilities (242)		19,107,816	20,129,874
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
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)		281,074,268	546,695,875
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,968,685	2,218,444
57	Accumulated Deferred Investment Tax Credits (255)	266-267	93,018,938	94,865,140
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	8,679,929	38,716,696
60	Other Regulatory Liabilities (254)	278	190,748,865	199,781,848
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)		1,272,308,390	983,763,085
64	Accum. Deferred Income Taxes-Other (283)		146,850,085	145,383,052
65	Total Deferred Credits (lines 56 through 64)		1,713,574,892	1,464,728,265
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,080,869,368	7,639,854,788

Name of Respondent Kentucky Utilities 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: 112 Line No.: 7 Column: c

Other Paid-In Capital (208-211) Without Purchase Accounting	$	563,858,083
Purchase Accounting Adjustment		2,032,588,751
Total for Other Paid-In Capital (208-211)	$	2,596,446,834

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Other Paid-In Capital (208-211) Without Purchase Accounting	$	563,858,083
Purchase Accounting Adjustment		2,032,588,751
Total for Other Paid-In Capital (208-211)	$	2,596,446,834

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Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	1,809,303,187
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000	$	(1,418,324,387)
Amortization of Purchase Accounting Adjustments - (net of deferred taxes of $7,438,679)		(8,425,586)
Total for Retained Earnings (215, 215.1, 216)	$	382,553,214

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)	$	382,553,214
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)		1,418,324,387
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)		8,425,586
Retained Earnings as of 12/31/2015, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,809,303,187
Retained Earnings prior to the 11/1/2010 acquisition		1,418,324,387
Cumulative post-acquisition net income		1,038,978,800
Cumulative post-acquisition dividends		(648,000,000)
Retained Earnings as of 12/31/2015, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,809,303,187

Schedule Page: 112 Line No.: 11 Column: d

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	1,728,986,179
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000	$	(1,418,324,387)
Amortization of Purchase Accounting Adjustments - (net of deferred taxes of $7,578,518)		(8,645,230)
Total for Retained Earnings (215, 215.1, 216)	$	302,016,562

As of December 31, 2014, in compliance with Docket No. EL12-27-000, the amount in the

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

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)	$	302,016,562
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)		1,418,324,387
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)		8,645,230
Retained Earnings as of 12/31/2014, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,728,986,179
Retained Earnings prior to the 11/1/2010 acquisition		1,418,324,387
Cumulative post-acquisition net income		805,661,792
Cumulative post-acquisition dividends		(495,000,000)
Retained Earnings as of 12/31/2014, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,728,986,179

Schedule Page: 112 Line No.: 15 Column: c

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(1,627,215)
Purchase Accounting Adjustment		1,339,815
Total for Accumulated Other Comprehensive Income (219)	$	(287,400)

Schedule Page: 112 Line No.: 15 Column: d

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(1,232,509)
Purchase Accounting Adjustment		1,465,817
Total for Accumulated Other Comprehensive Income (219)	$	233,308

Schedule Page: 112 Line No.: 21 Column: c

Other Long-Term Debt (224) Without Purchase Accounting	$	-
Purchase Accounting Adjustment		369,516
Total for Other Long-Term Debt (224)	$	369,516

Schedule Page: 112 Line No.: 21 Column: d

Other Long-Term Debt (224) Without Purchase Accounting	$	-
Purchase Accounting Adjustment		522,778
Total for Other Long-Term Debt (224)	$	522,778

Schedule Page: 112 Line No.: 59 Column: c

Other Deferred Credits (253) Without Purchase Accounting	$	8,679,929
Purchase Accounting Adjustment		-
Total for Other Deferred Credits (253)	$	8,679,929

Schedule Page: 112 Line No.: 59 Column: d

Other Deferred Credits (253) Without Purchase Accounting	$	38,495,004
Purchase Accounting Adjustment		221,692

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Total for Other Deferred Credits (253)	$	38,716,696

Schedule Page: 112 Line No.: 60 Column: c

Other Regulatory Liabilities (254) Without Purchase Accounting	$	153,390,897
Purchase Accounting Adjustment		37,357,968
Total for Other Regulatory Liabilities (254)	$	190,748,865

Schedule Page: 112 Line No.: 60 Column: d

Other Regulatory Liabilities (254) Without Purchase Accounting	$	136,098,871
Purchase Accounting Adjustment		63,682,977
Total for Other Regulatory Liabilities (254)	$	199,781,848

Schedule Page: 112 Line No.: 64 Column: c

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	132,317,835
Purchase Accounting Adjustment		14,532,250
Total for Accumulated Deferred Income Taxes - Other (283)	$	146,850,085

Schedule Page: 112 Line No.: 64 Column: d

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	120,524,136
Purchase Accounting Adjustment		24,858,916
Total for Accumulated Deferred Income Taxes - Other (283)	$	145,383,052

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	1,729,060,333	1,737,199,654		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	883,449,371	942,074,055		
5	Maintenance Expenses (402)	320-323	133,441,019	130,920,339		
6	Depreciation Expense (403)	336-337	209,271,260	187,157,353		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	10,864,312	9,436,591		
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	38,301,170	35,625,305		
15	Income Taxes - Federal (409.1)	262-263	-19,453,420	-94,167,437		
16	- Other (409.1)	262-263	1,153,593	6,539,531		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	538,010,714	414,668,257		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	376,623,459	189,296,966		
19	Investment Tax Credit Adj. - Net (411.4)	266				
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)		156	546		
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)		1,418,414,404	1,442,956,482		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		310,645,929	294,243,172		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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
1,729,060,333	1,737,199,654					2
						3
883,449,371	942,074,055					4
133,441,019	130,920,339					5
209,271,260	187,157,353					6
						7
10,864,312	9,436,591					8
						9
						10
						11
						12
						13
38,301,170	35,625,305					14
-19,453,420	-94,167,437					15
1,153,593	6,539,531					16
538,010,714	414,668,257					17
376,623,459	189,296,966					18
						19
						20
						21
156	546					22
						23
						24
1,418,414,404	1,442,956,482					25
310,645,929	294,243,172					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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)		310,645,929	294,243,172		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		43,936	34,253		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		31,727	8,305		
33	Revenues From Nonutility Operations (417)		7,321	28,869		
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)		124,234	34,064		
38	Allowance for Other Funds Used During Construction (419.1)		1,975,811	1,388,314		
39	Miscellaneous Nonoperating Income (421)		2,179,817	1,082,421		
40	Gain on Disposition of Property (421.1)		51,682	10,595		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,351,074	2,570,211		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			2,855		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,650,752	1,597,409		
46	Life Insurance (426.2)		-1,899,664	-1,372,796		
47	Penalties (426.3)		9,180	17,591		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		945,577	1,132,401		
49	Other Deductions (426.5)		1,832,938	1,283,278		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,538,783	2,660,738		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	10,827	10,715		
53	Income Taxes-Federal (409.2)	262-263	-1,231,898	-1,254,451		
54	Income Taxes-Other (409.2)	262-263	-224,662	-228,548		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	726,377	545,810		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	396,414	59,364		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		1,846,202	1,871,259		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-2,961,972	-2,857,097		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,774,263	2,766,570		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		75,653,843	70,702,345		
63	Amort. of Debt Disc. and Expense (428)		2,958,222	2,940,774		
64	Amortization of Loss on Reaquired Debt (428.1)		683,508	626,896		
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)		1,170	5,790		
68	Other Interest Expense (431)		3,307,390	3,509,327		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		720,594	445,556		
70	Net Interest Charges (Total of lines 62 thru 69)		81,883,539	77,339,576		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		233,536,653	219,670,166		
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)		233,536,653	219,670,166		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 114 Line No.: 17 Column: c

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	526,506,249
Amortization of Purchase Accounting Adjustment		11,504,465
Total for Provision for Deferred Income Taxes (410.1)	$	538,010,714

Schedule Page: 114 Line No.: 17 Column: d

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	404,001,013
Amortization of Purchase Accounting Adjustment		10,667,244
Total for Provision for Deferred Income Taxes (410.1)	$	414,668,257

Schedule Page: 114 Line No.: 17 Column: g

See footnote data detail on Schedule Page: 114, Line No.: 17, Column c.

Schedule Page: 114 Line No.: 17 Column: h

See footnote data detail on Schedule Page: 114, Line No.: 17, Column d.

Schedule Page: 114 Line No.: 18 Column: c

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	365,178,613
Amortization of Purchase Accounting Adjustment		11,444,846
Total for Provision for Deferred Income Taxes (411.1)	$	376,623,459

Schedule Page: 114 Line No.: 18 Column: d

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	178,689,501
Amortization of Purchase Accounting Adjustment		10,607,465
Total for Provision for Deferred Income Taxes (411.1)	$	189,296,966

Schedule Page: 114 Line No.: 18 Column: g

See footnote data detail on Schedule Page: 114, Line No.: 18, Column c.

Schedule Page: 114 Line No.: 18 Column: h

See footnote data detail on Schedule Page: 114, Line No.: 18, Column d.

Schedule Page: 114 Line No.: 39 Column: c

Miscellaneous Nonoperating Income (421) Without Purchase Accounting	$	1,973,595
Amortization of Purchase Accounting Adjustment		206,222
Total for Miscellaneous Nonoperating Income (421)	$	2,179,817

Schedule Page: 114 Line No.: 39 Column: d

Miscellaneous Nonoperating Income (421) Without Purchase Accounting	$	876,199
Amortization of Purchase Accounting Adjustment		206,222
Total for Miscellaneous Nonoperating Income (421)	$	1,082,421

Schedule Page: 114 Line No.: 46 Column: c

The balance includes the increase in the cash surrender value less the monthly premium amounts that are paid from the cash surrender value balance.

Schedule Page: 114 Line No.: 46 Column: d

The balance includes the increase in the cash surrender value less the monthly premium amounts that are paid from the cash surrender value balance.

Schedule Page: 114 Line No.: 55 Column: c

Provision for Deferred Income Taxes (410.2) Without Purchase Accounting	$	641,826
Amortization of Purchase Accounting Adjustment		84,551
Total for Provision for Deferred Income Taxes (410.2)	$	726,377

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 55 Column: d

Provision for Deferred Income Taxes (410.2) Without Purchase Accounting	$	461,259
Amortization of Purchase Accounting Adjustment		84,551
Total for Provision for Deferred Income Taxes (410.2)	$	545,810

Schedule Page: 114 Line No.: 56 Column: c

Provision for Deferred Income Taxes (411.2) Without Purchase Accounting	$	392,084
Amortization of Purchase Accounting Adjustment		4,330
Total for Provision for Deferred Income Taxes (411.2)	$	396,414

Schedule Page: 114 Line No.: 56 Column: d

Provision for Deferred Income Taxes (411.2) Without Purchase Accounting	$	55,033
Amortization of Purchase Accounting Adjustment		4,331
Total for Provision for Deferred Income Taxes (411.2)	$	59,364

Schedule Page: 114 Line No.: 62 Column: c

Interest on Long-Term Debt (427) Without Purchase Accounting	$	75,807,104
Amortization of Purchase Accounting Adjustment		(153,261)
Total for Interest on Long-Term Debt (427)	$	75,653,843

Schedule Page: 114 Line No.: 62 Column: d

Interest on Long-Term Debt (427) Without Purchase Accounting	$	70,856,019
Amortization of Purchase Accounting Adjustment		(153,674)
Total for Interest on Long-Term Debt (427)	$	70,702,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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		302,016,562	230,346,396
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Rounding		-1	
5				
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)		233,536,653	219,670,166
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		-153,000,000	(148,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-153,000,000	(148,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		382,553,214	302,016,562
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)		382,553,214	302,016,562
	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	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	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
Kentucky Utilities 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)	233,536,653	219,670,166
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	209,271,260	187,157,353
5	Amortization of Plant	10,864,312	9,436,591
6			
7			
8	Deferred Income Taxes (Net)	163,920,162	227,281,396
9	Investment Tax Credit Adjustment (Net)	-1,775,102	-1,800,159
10	Net (Increase) Decrease in Receivables	70,785,504	-67,977,090
11	Net (Increase) Decrease in Inventory	905,685	-24,084,329
12	Net (Increase) Decrease in Allowances Inventory	18,516	134,637
13	Net Increase (Decrease) in Payables and Accrued Expenses	-13,558,919	32,206,310
14	Net (Increase) Decrease in Other Regulatory Assets	-49,682,443	-91,890,194
15	Net Increase (Decrease) in Other Regulatory Liabilities	17,292,025	-14,344,308
16	(Less) Allowance for Other Funds Used During Construction	1,975,811	942,758
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	17,877,880	91,572,741
19	Change in Other Deferred Debits	-4,985,715	-3,783,826
20	Change in Other Deferred Credits	-656,313	4,176,182
21	Interest Rate Swaps Settlement	-43,688,302	
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	608,149,392	566,812,712
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-499,334,059	-589,441,421
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-1,975,811	-942,758
31	Other (provide details in footnote):	-21,520,266	-15,528,654
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-518,878,514	-604,027,317
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	73,359	6,320
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)		

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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):	6,510,737	1,202,912
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-512,294,418	-602,818,085
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	245,094,386	-2,138,398
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		85,631,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	245,094,386	83,492,602
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		91,000,000
77			
78	Net Decrease in Short-Term Debt (c)	-187,631,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-153,000,000	-148,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-95,536,614	26,492,602
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	318,360	-9,512,771
87			
88	Cash and Cash Equivalents at Beginning of Period	11,136,663	20,649,433
89			
90	Cash and Cash Equivalents at End of period	11,455,023	11,136,662

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FOOTNOTE DATA

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Other changes in Net Utility Plant	$ (115,094,990)
Accumulated Provision for Uncollectible Accounts - Debit	4,797,655
Amortization of Debt Expenses and Losses on Bonds	2,964,279
Unamortized Discount on Long-Term Debt - Debit	677,451
Unamortized Discount on Short-Term Debt - Debit	35,798
Net increase in Prepayments and Other Assets	(1,706,023)
Net decrease in Other Deferred Debits	2,385,741
Net increase in Other Comprehensive Income	(394,706)
Net decrease in Customer Advances for Construction	(249,760)
Net increase in Asset Retirement Obligations	151,176,561
Net decrease in the Provision for Pension and Postretirement Benefits	(5,748,634)
Pension and Postretirement Funding	(20,885,500)
Net decrease in Other Liabilities	(4,381)
Reserve for Depreciation	144,035
Change in Deferred Income Taxes - Purchase Accounting	59,619
Change in Unappropriated Undistributed Subsidiary Earnings - Purchase Accounting	(126,001)
Change in Pollution Control Bonds - Purchase Accounting	(153,262)
Rounding	(2)
Total	$ 17,877,880

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Other operating cash flows:

Other changes in Net Utility Plant	$ (3,183,342)
Accumulated Provision for Uncollectible Accounts - Debit	8,005,373
Amortization of Debt Expenses and Losses on Bonds	3,448,403
Unamortized Discount on Long-Term Debt - Debit	698,583
Unamortized Discount on Short-Term Debt - Credit	(6,044)
Net increase in Prepayments and Other Assets	(3,231,988)
Net decrease in Other Deferred Debits	601,722
Net increase in Other Comprehensive Income	(315,489)
Net decrease in Customer Advances for Construction	(663,912)
Net increase in Asset Retirement Obligations	32,105,982
Net increase in the Provision for Pension and Postretirement Benefits	59,416,001
Pension and Postretirement Funding	(4,804,100)
Net decrease in Other Liabilities	(4,381)
Reserve for Depreciation	(274,169)
Change in Deferred Income Taxes - Purchase Accounting	59,779
Change in Unappropriated Undistributed Subsidiary Earnings - Purchase Accounting	(126,001)
Change in Pollution Control Bonds - Purchase Accounting	(153,674)
Rounding	(2)
Total	$ 91,572,741

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Other plant investing cash flows:

Costs of removal of utility plant	$ (20,799,674)
Allowance for funds used during construction - borrowed	(720,592)
	$ (21,520,266)

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Other plant investing cash flows:

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FOOTNOTE DATA

Costs of removal of utility plant	$	(15,528,654)

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Other investing cash flows:

Proceeds for Key Man Life Insurance	$	6,510,737

Schedule Page: 120 Line No.: 53 Column: c

Other investing cash flows:

Proceeds for Key Man Life Insurance	$	1,202,912

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Other financing cash flows:

LG&E and KU Energy LLC Equity Contribution	$	91,000,000

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Cash and Cash Equivalents is comprised of the following amounts:

Cash (131)	$	7,140,987
Working Fund (135)		61,030
Temporary Cash Investments (136)		4,253,006
Total Cash and Cash Equivalents	$	11,455,023

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Cash and cash equivalents is comprised of the following amounts:

Cash (131)	$	7,008,866
Working Fund (135)		61,030
Temporary Cash Investments (136)		4,066,766
Total Cash and Cash Equivalents	$	11,136,662

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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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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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 KU and LG&E, with a capacity of 642 MW (501 MW and 141 MW to KU and LG&E).

***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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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).

***KPSC* -** Kentucky Public Service Commission, the state agency that has jurisdiction over the regulation of rates and service of utilities in Kentucky.

***KU 2010 Mortgage Indenture* -** KU's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as supplemented.

***kWh* -** kilowatt hour, basic unit of electrical energy.

***LIBOR* -** London Interbank Offered Rate.

***MATS* -** Mercury and Air Toxics Standards, regulations promulgated by the EPA.

***MW* -** megawatt, one thousand kilowatts.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

TRA **-** Tennessee Regulatory Authority, the state agency that has jurisdiction over the regulation of rates and service of utilities in Tennessee.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

VSCC **-** Virginia State Corporation Commission, the state agency that has jurisdiction over the regulation of Virginia corporations, including utilities.

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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

KU is engaged in the generation, transmission, distribution and sale of electricity. KU also serves customers in Virginia (under the Old Dominion Power name) and in Tennessee under the KU name.

KU has no controlling interest in any Variable Interest Entities (VIEs). All other investments are carried at cost or fair value.

KU'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

KU is a cost-based rate-regulated utility for which rates are set by regulators to enable KU to recover the costs of providing electric 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

KU'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." KU 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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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 KU'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. KU 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.

KU 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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NOTES TO FINANCIAL STATEMENTS (Continued)

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	$ 5	$ -	$ 5	$ 2
2014	4	8	(3)	7	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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NOTES TO FINANCIAL STATEMENTS (Continued)

Cash

Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered to be cash equivalents.

Fair Value Measurements

KU 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. KU 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.

KU 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, KU'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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NOTES TO FINANCIAL STATEMENTS (Continued)

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

KU 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. KU and 11 other electric utilities are equity owners of OVEC. OVEC's power is currently supplied to KU and 12 other companies affiliated with the various owners. KU owns 2.5% of OVEC's common stock. Pursuant to a power purchase agreement, KU is contractually entitled to its ownership percentage of OVEC's output, which is approximately 53 MW.

KU's investment in OVEC is not significant. The direct exposure to loss as a result of KU's involvement with OVEC is generally limited to the value of its investment; however, KU 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. KU 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. KU 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.

KU generally does not record AFUDC, except for certain instances in its FERC approved rates charged to its municipal customers, as a return is provided on construction work in progress.

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. KU's weighted-average rates of depreciation for regulated utility plant were 3.71% and 3.63% 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, KU 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.

KU accounts for emission allowances as intangible assets. KU 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)

KU 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.

KU 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. KU is a single reporting unit.

KU 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.

KU 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

KU 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 KU 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

KU does not directly sponsor any defined benefit plan. KU participates in defined benefit pension and other postretirement plans. These plans are sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to KU 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.

LKE uses 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

KU is included in PPL's consolidated U.S. federal income tax return.

Significant management judgment is required in developing KU'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. KU uses a two-step process to evaluate tax positions. The first step requires KU 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 KU 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

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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 KU'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.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU 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 KU 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 KU 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.

KU defers investment tax credits when the credits are utilized and amortize the deferred amounts over the average lives of the related assets.

KU recognizes interest and penalties in "Income Taxes" on its Statements of Income.

KU'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."

KU's income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if KU filed a separate return. Tax benefits are not shared between companies. KU 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. KU's intercompany tax receivables (payables) were ($5) million and $60 million at December 31, 2015 and 2014.

<u>Taxes, Other Than Income</u>

KU 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

<u>Leases</u>

KU 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, 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. See Note 4 for further discussion of the fuel adjustment clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2015	2014
Fuel	$ 97	$ 100
Materials and supplies	50	49
Total	$ 147	$ 149

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, KU 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 KU 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 KU. See Note 8 for additional information.

Presentation of Debt Issuance Costs

Effective December 31, 2015, KU 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 KU to reclassify debt issuance costs not associated with a line of credit

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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, KU 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 KU to reclassify deferred tax assets and deferred tax liabilities from current to noncurrent on the Balance Sheet, and did not have a significant impact. KU reclassified $8 million and $4 million from current deferred tax assets and liabilities to noncurrent deferred tax liabilities on the Balance Sheet as of December 31, 2014.

2. Preferred Securities

KU is authorized to issue up to 5,300,000 shares of preferred stock and 2,000,000 shares of preference stock without par value. KU had no preferred or preference 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.

KU’s provision for deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC, VSCC, TRA 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 KU's deferred income tax assets and liabilities at December 31 were as follows:

	2015	2014
Deferred Tax Assets		
Federal loss carryforwards (a)	$ 97	$ -
Regulatory liabilities	28	41
Deferred investment tax credits	36	37
Income taxes due to customers	-	2
Derivative liability	-	13
Other	7	7
Total deferred tax assets	168	100
Deferred Tax Liabilities		
Plant - net	1,164	922
Regulatory assets	44	53
Other	6	7
Total deferred tax liabilities	1,214	982
Net deferred tax liability	$ 1,046	$ 882

(a) Increase in Federal loss carryforwards primarily relates to the extension of bonus depreciation.

KU expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

At December 31, 2015, KU had $279 million of federal net operating loss carryforwards that expire in 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:

	Year Ended December 31, 2015	Year Ended December 31, 2014
Income Tax Expense (Benefit)		
Current - Federal	$ (21)	$ (95)
Current - State	1	6
Total Current Expense (Benefit)	(20)	(89)
Deferred - Federal	240	212
Deferred - State	19	14
Total Deferred Expense, excluding operating loss carryforwards	259	226
Investment tax credit, net - Federal	(2)	(2)
Tax benefit of operating loss carryforwards		
Deferred - Federal	(97)	-
Total Tax Benefit of Operating Loss Carryforwards	(97)	-
Total income tax expense (a)	$ 140	$ 135
Total income tax expense - Federal	$ 120	$ 115
Total income tax expense - State	20	20
Total income tax expense (a)	$ 140	$ 135

(a) Excludes deferred federal and state tax expense (benefit) recorded to OCI of less than $(1) million in 2015 and 2014.

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	Year Ended December 31, 2015	Year Ended December 31, 2014
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 131	$ 124
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	13	13
Amortization of investment tax credit	(2)	(2)
Other	(2)	-
Total increase (decrease)	9	11
Total income tax expense	$ 140	$ 135
Effective income tax rate	37.4%	38.0%

	Year Ended December 31, 2015	Year Ended December 31, 2014
Taxes, other than income		
Property and other	$ 29	$ 27
Total	$ 29	$ 27

Unrecognized Tax Benefits

KU's income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if KU filed a separate return. Based on this tax sharing agreement, KU 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

KU 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.

KU is subject to the jurisdiction of the KPSC, FERC, VSCC and TRA.

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KU'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 other means. As such, KU 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. KU 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. KU's customer rates will continue to reflect the original contracted prices for these contracts.

KU's Virginia base rates are calculated based on a return on rate base (net utility plant plus working capital less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities, except the levelized fuel factor, are excluded from the return on rate base utilized in the calculation of Virginia base rates. Therefore, no return is earned on the related assets.

KU's rates to municipal customers for wholesale requirements are calculated based on annual updates to a rate formula that utilizes a return on rate base (net utility plant plus working capital less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities are excluded from the return on rate base utilized in the development of municipal rates. Therefore, no return is earned on the related assets.

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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	$	11		1
Fuel adjustment clause		-		2
Other		8		1
Total current regulatory assets	$	19	$	4
Noncurrent Regulatory Assets:				
Defined benefit plans	$	125	$	133
Storm costs		28		35
Unamortized loss on debt		9		10
Interest rate swaps		43		33
AROs		86		51
Plant retirement costs		6		-
Other		6		6
Total noncurrent regulatory assets	$	303	$	268
Current Regulatory Liabilities:				
Demand side management	$	4	$	1
Fuel adjustment clause		12		-
Other		3		4
Total current regulatory liabilities	$	19	$	5
Noncurrent Regulatory Liabilities:				
Coal contracts (a)	$	10	$	34
Power purchase agreement - OVEC (a)		26		29
Net deferred tax assets		-		2
Defined benefit plans		24		16
Interest rate swaps		41		42
Other		1		2
Total noncurrent regulatory liabilities	$	102	$	125

(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 and liabilities 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 and liabilities are adjusted at least annually or whenever the funded status of defined benefit plans is re-measured. Of the regulatory asset and liability balances recorded, costs of $9 million are expected to be amortized into net periodic defined benefit costs in 2016 in accordance with KU'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 KU'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 $4 million. 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 in 2016.

Storm Costs

KU has the ability to request from the KPSC and VSCC, as applicable, 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, KU can request recovery of those expenses in a base rate case and begin amortizing the costs when recovery starts. KU'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 2040.

Environmental Cost Recovery

Kentucky law permits KU 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, KU 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.

Fuel Adjustment Clauses

KU'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 KU'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.

KU also employs a levelized fuel factor mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any under- or over-recovery of fuel expenses from the prior year. 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

KU'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. KU'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, KU 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, KU 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 $500 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

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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.

AROs

The accretion and depreciation expenses related to KU'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.

Coal Contracts

As a result of purchase accounting associated with PPL's acquisition of LKE, KU'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.

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

KU'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.

Plant Retirement Costs

The 2014 Kentucky rate case settlement that became effective July 1, 2015, provided for deferred recovery of costs associated with Green River's remaining coal-fired generating units through their retirement date, which occurred in September 2015. These costs include inventory write-downs and separation benefits and will be amortized over three years.

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 electricity rates of $125 million. 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 mechanism. The settlement agreement provided for deferred recovery of costs associated with KU's retirement of Green River Units 3 and 4. The new regulatory asset will be amortized over three years. The settlement also provided for regulatory asset treatment for the difference between pension expense calculated in accordance with KU'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, KU and LG&E 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 KU and LG&E’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 KU and LG&E 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 KU and LG&E 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, KU 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 KU approximately $678 million. The applications request an authorized 10% return on equity with respect to KU’s ECR mechanism consistent with the 2014 Kentucky rate case approved in June 2015.

FERC Wholesale Formula Rates

In September 2013, KU filed an application with the FERC to adjust the formula rate under which KU provided wholesale requirements power sales to 12 municipal customers. Among other changes, the application requests an amended formula whereby KU would charge cost-based rates with a subsequent true-up to actual costs, replacing the current formula which does not include a true-up. KU's application proposed an authorized return on equity of 10.7%. Certain elements, including the new formula rate, became effective April 23, 2014, subject

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to refund. In April 2014, nine municipalities submitted notices of termination, under the original notice period provisions, to cease taking power under the wholesale requirements contracts. Such terminations are to be effective in 2019, except in the case of one municipality with a 2017 effective date. In addition, a tenth municipality has become a transmission-only customer as of June 2015. In July 2014, KU agreed on settlement terms with the two municipal customers that did not provide termination notices and filed the settlement proposal with the FERC for its approval. In August 2014, the FERC issued an order on the interim settlement agreement allowing the proposed rates to become effective pending a final order. During the fourth quarter of 2015, the FERC approved the settlement agreement resolving the rate case with respect to these two municipalities, including approval of the formula rate with a true-up provision and authorizing a return on equity of 10% or the return on equity awarded to other parties in this case, whichever is lower. In August 2015, KU filed a partial settlement agreement with the nine terminating municipalities, resolving all but one open matter with one municipality. The settlement was approved by FERC in the fourth quarter of 2015, including authorizing the agreed-upon refunds, approving the formula rate with a true-up provision, and authorizing a 10.25% return on equity. Refunds to both the remaining municipals and the departing municipals were issued during the fourth quarter of 2015 totaling $3.4 million. A single remaining unresolved issue with one terminating municipality is in FERC litigation proceedings. Hearings on the dispute were conducted in January 2016 and preliminary rulings on the matter may occur in mid- or late-2016. KU cannot predict the ultimate outcome of this FERC proceeding, but the amounts under continuing dispute are not estimated to be significant.

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5. Financing Activities

Credit Arrangements and Short-term Debt

KU maintains credit facilities 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 facilities were 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	$ 400	-	$ 48	$ 352
Letter of Credit Facility (a) (b) (c)	Oct. 2017	198	-	198	-
Total KU Credit Facilities		$ 598	-	$ 246	$ 352

	December 31, 2014	
	Borrowed	Letters of Credit and Commercial Paper Issued
Syndicated Credit Facility (a) (b)	-	$ 236
Letter of Credit Facility (a) (b) (c)	-	198
Total KU Credit Facilities	-	$ 434

(a) KU pays customary fees under its facilities 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 facilities and other customary covenants. Additionally, as it relates to the syndicated and bilateral credit facilities and subject to certain conditions, KU may request up to a $100 million increase in its facility's capacity.
(c) KU's letter of credit facility agreement allows for certain payments under the letter of credit facility to be converted to loans rather than requiring immediate payment.

In January 2016, the expiration date for KU's syndicated credit facility expiring in July 2019 was extended to December 2020.

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KU 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 KU'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**
0.72%	$ 350	$ 48	$ 302

December 31, 2014	
Weighted - Average Interest Rate	**Commercial Paper Issuances**
0.49%	$ 236

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Long-term Debt

	Weighted - Average Rate	Maturities (c)	December 31, 2015
First Mortgage Bonds (a) (b)	3.74%	2020 - 2045	$ 2,351
Total Long-term Debt Before Adjustments			2,351
Other			
Unamortized discount			(10)
Unamortized debt issuance costs			(15)
Total Long-term Debt			2,326
Less current portion of Long-term Debt			-
Total Long-term Debt, noncurrent			$ 2,326

			December 31, 2014
First Mortgage Bonds (a) (b)	3.44%	2015 - 2043	$ 2,101
Total Long-term Debt Before Adjustments			2,101
Other			
Unamortized discount			(10)
Unamortized debt issuance costs			(12)
Total Long-term Debt			2,079
Less current portion of Long-term Debt			250
Total Long-term Debt, noncurrent			$ 1,829

(a) KU's first mortgage bonds are secured by the lien of the KU 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of KU'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. The aggregate carrying value of the property subject to the lien was $5.7 billion and $5.5 billion at December 31, 2015 and 2014.

(b) Includes KU'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 KU 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 KU. The related revenue bond documents allow KU 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 KU that were in a term rate mode totaled $27 million. At December 31, 2015, the aggregate tax-exempt revenue bonds issued on behalf of KU that were in a variable rate mode totaled $324 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, $96 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 KU 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 KU to convert the bonds to other interest rate modes.

Certain of the variable rate tax-exempt revenue bonds totaling $228 million at December 31, 2015, are subject to tender for purchase by KU at the option of the holder and to mandatory tender for purchase by KU 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 $500 million in 2020 and $1,851 million after 2020.

In September 2015, KU issued $250 million of 3.30% First Mortgage Bonds due 2025 and $250 million of 4.375% First Mortgage Bonds due 2045. KU received proceeds of $248 million for each issuance, 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.

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

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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. KU 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. KU 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, KU 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 KU 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 $1.6 billion were restricted for purposes of paying dividends to LKE, and net assets of $1.7 billion were available for payment of dividends to LKE. KU believes it will not be required to change its current dividend practices as a result of the foregoing requirement. In addition, under Virginia law, KU is prohibited from making loans to affiliates without the prior approval of the VSCC. There are no comparable statutes under Kentucky law applicable to KU. However, orders from the KPSC require KU to obtain prior consent or approval before lending amounts to PPL or LKE.

6. Acquisitions, Development and Divestitures

From time to time, KU 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, KU retired the remaining two coal-fired generating units at the Green River plant on September 30, 2015. KU incurred costs of $6 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. See Note 4 for more information related to the regulatory recovery of the costs associated with the retirement of the Green River 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. KU and LG&E 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.

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7. Leases

KU has entered into various agreements for the lease of office space, vehicles, land and other equipment.

Rent - Operating Leases

Rent expense for operating leases was $11 million and $10 million for the years ended December 31, 2015 and 2014.

Total future minimum rental payments for all operating leases are estimated to be:

2016	$	10
2017		9
2018		7
2019		5
2020		5
Thereafter		11
Total	$	47

8. Retirement and Postemployment Benefits

Defined Benefits

KU does not directly sponsor any defined benefit plans. The majority of employees are eligible for pension benefits under a non-contributory defined benefit pension plan sponsored by LKE. KU is allocated a portion of the funded status and costs of the plan sponsored by LKE based on its participation in the plan, which management believes are reasonable. The LKE plan was 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.

For the pension plan KU participates in, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2016 are $8 million ($1 million amortization of prior service cost and $7 million amortization of actuarial loss). For the postretirement plan KU participates in, the estimated amount to be amortized from regulatory liabilities into net periodic defined benefit costs in 2016 is $1 million (amortization of prior service cost).

LKE adopted the new mortality tables issued by the Society of Actuaries in October 2014 (RP-2014 base tables) for its defined benefit pension and other postretirement benefit plans at December 31, 2014 and 2015. In addition, LKE updated the basis for estimating projected mortality improvements and selected the IRS BB-2D two-dimensional improvement scales on a generational basis for its defined benefit pension and other postretirement benefit plans. 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 also resulted in an increased allocations from LKE to KU for defined benefit pension and other postretirement benefit obligations and future expense and a decrease in allocated funded status.

The amounts recognized in KU’s regulatory assets at December 31 were as follows:

	Pension Benefits	
	2015	**2014**
Amounts recognized in regulatory assets (pre-tax) consists of:		
Prior service cost (credit)	$ 4	$ 6
Net actuarial (gain) loss	121	127
Total	$ 125	$ 133

Allocations to KU 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 $9 million and $3 million in 2015 and 2014. 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 $2 million each in 2015 and 2014. These allocated amounts are based on KU’s participation in those plans, which management believes is reasonable.

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 KU'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. Of the costs charged to operating expense or regulatory assets, excluding amounts charged to construction and other non-expense accounts, $1 million was recorded as regulatory assets during 2015.

The actuarially determined obligations of current active employees and retired employees of KU are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to KU for pension benefits resulted in a liability of $46 million and $59 million at December 31, 2015 and 2014. Allocations to KU for other postretirement benefits resulted in a liability of $42 million and $52 million at December 31, 2015 and 2014.

Plan Assets - Pension Plans

The pension plan sponsored by LKE 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 KU'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 investment guidelines as of the end of 2015 are presented below.

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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 KU and LG&E Retirement Plan.
(b) Includes commingled debt funds, which are treated as debt securities for asset allocation purposes.

LKE's plan assets are invested solely in the Master Trust, which is fully disclosed below. The fair value of these 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 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

LKE's defined benefit pension plans have the option to utilize available prior year credit balances to meet current and future contribution requirements. However, KU contributed $9 million to LKE’s pension plans on behalf of KU employees in January 2016.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the LKE plan for KU retirees.

	Allocated from LKE Pension Plan
2016	$ 27
2017	28
2018	28
2019	28
2020	29
2020-2025	150

Savings Plans

Substantially all employees of KU are eligible to participate in deferred savings plans (401(k)s). Employer contributions to the plans were $4 million each in 2015 and 2014.

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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	62.00%	$ 65	$ 19	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00%	43	9	1
Trimble County Unit 2	60.75%	803	113	15
Trimble County Units 5-6	71.00%	70	15	-
Trimble County Units 7-10	63.00%	121	23	-
Cane Run Unit 7	78.00%	411	6	5
E.W. Brown Solar Unit	61.00%	-	-	6
December 31, 2014				
Generating Plants				
E.W. Brown Units 6-7	62.00%	$ 65	$ 15	$ 1
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00%	42	6	-
Trimble County Unit 2	60.75%	797	98	17
Trimble County Units 5-6	71.00%	70	11	-
Trimble County Units 7-10	63.00%	120	18	1
Cane Run Unit 7	78.00%	-	-	403

KU provides its own funding for its share of each of the above facilities. KU 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

KU enters into purchase contracts to supply the coal and natural gas requirements for generation facilities. These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Coal	2022
Coal Transportation and Fleeting Services	2024
Natural Gas Transportation	2026

KU 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	$	8
2017		8
2018		8
2019		9
2020		9
Thereafter		193
	$	235

In addition, KU had total energy purchases under the OVEC power purchase agreement of $7 million and $8 million for the years ended December 31, 2015 and 2014.

Legal Matters

KU is involved in legal proceedings, claims and litigation in the ordinary course of business. KU cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

E.W. Brown Environmental Claims

In October 2015, KU received a notice of intent from Earthjustice and the Sierra Club informing certain federal and state agencies of the Sierra Club's intent to file a citizen suit, following expiration of the mandatory 60-day notification period, for alleged violations of the Clean Water Act. The claimant alleges discharges at the E.W. Brown plant in violation of applicable rules and the plant's water discharge permit. The claimant asserts that, unless the alleged discharges are promptly brought into compliance, it intends to seek civil penalties, injunctive relief and attorney's fees. In November 2015, the claimants submitted an amended notice of intent to add the Kentucky Waterways Alliance as a claimant. The parties have conducted limited settlement discussions in the matter. KU cannot predict the outcome of this matter or the potential impact on the operations of the E. W. Brown plant, including increased capital or operating costs, if any.

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, KU 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 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. KU 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.

KU 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. KU 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 KU 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.

KU is entitled to recover, through the ECR mechanism, certain costs of complying with the Clean Air Act, as 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, VSCC, TRA or the FERC. KU 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 KU believes are subject to cost recovery.

Although KU 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 achieved by 2018. KU 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 KU's Green River 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.

KU 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. KU 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 $17 million. KU 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 KU, it can influence the permitting of large capital projects at KU'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.

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

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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, KU may need to modify its current portfolio of generating assets during the next decade and/or participate in an allowance trading program.

KU 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. KU cannot predict the outcome of this matter or the potential impact, if any, on plant operations, or future capital or operating needs. KU believes that the costs, which could be significant, would be subject to cost recovery.

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.

Water/Waste

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. KU 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.

KU is currently pursuing KPSC approval for a compliance plan providing for construction of additional landfill

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capacity at the Brown Station, closure of impoundments at the Trimble County, Brown, and Ghent stations, and construction of process water management facilities at those plants. In addition to the foregoing measures required for compliance with federal CCR rule requirements, KU is also proposing to close impoundments at the retired Green River, Pineville, and Tyrone plants to comply with applicable state law requirements. KU currently estimate the cost of these CCR compliance measures at $661 million. See Note 4 for additional information.

In connection with the final CCR rule, KU 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 KU'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.

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. KU continues to assess the requirements of this complex rule to determine available compliance strategies. KU 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.

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. KU

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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. KU 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.

Superfund and Other Remediation

KU 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 KU 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 KU. To date, the costs of these sites have not been significant.

There are additional sites, formerly owned or operated by KU predecessors or affiliates. KU 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 KU to take more extensive assessment and remedial actions at former coal gas manufacturing plants. KU cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, KU 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 KU'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 KU'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 KU 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.

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Guarantees and Other Assurances

In the normal course of business, KU 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, KU 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. KU's proportionate share of OVEC's outstanding debt was $138 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.

KU 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 KU, 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

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. 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. 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. 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.

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Support Costs

LKS provides KU with administrative, management and support services. The costs of these services are charged to KU as direct support costs. General costs that cannot be directly attributed to a specific LKE subsidiary are allocated and charged to KU 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 KU $185 million and $165 million for the years ended December 31, 2015 and 2014, including amounts applied to accounts that are further distributed between capital and expense on KU'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 KU for fuel purchases and other costs for products or services provided by third parties. KU and LG&E also provide services to each other and to LKS. Billings between KU and LG&E 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 KU are reimbursed through LKS.

Intercompany Derivatives

Periodically, KU 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	$ 11	$ 11	$ -	$ -
Total assets	$ 11	$ 11	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ -	$ -	$ -	$ -
Total price risk management liabilities	$ -	$ -	$ -	$ -

	December 31, 2014			
	Total	**Level 1**	**Level 2**	**Level 3**
Assets				
Cash and cash equivalents	$ 11	$ 11	$ -	$ -
Total assets	$ 11	$ 11	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 33	$ -	$ 33	$ -
Total price risk management liabilities	$ 33	$ -	$ 33	$ -

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage interest rate risk, KU uses interest rate contracts such as forward-starting 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. 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 KU'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	$ 2,326	$ 2,467	$ 2,079	$ 2,313

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 KU. These risks are significantly mitigated due to recovery mechanisms in place.

Interest rate risk

- KU is exposed to interest rate risk associated with forecasted fixed-rate debt issuances. KU utilizes forward starting interest rate swaps to hedge changes in benchmark interest rates, when appropriate, in connection with future debt issuances.

- KU is exposed to interest rate risk associated with debt securities and derivatives held by defined benefit plans.

Commodity price risk

- KU's rates include certain mechanisms for fuel 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

- KU 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 KU defaults on its obligation, KU 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 KU would be recoverable from customers through applicable rate mechanisms, thus mitigating its financial risk.

KU 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. KU 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.

KU had no obligation to return cash collateral under master netting arrangements at December 31, 2015 and 2014.

KU did not post any 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

KU 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

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appropriate. Risk limits under KU'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, KU 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, KU issued first mortgage bonds totaling $500 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.

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 KU'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.

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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)

Offsetting Derivative Instruments

KU 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.

KU has elected not to offset derivative assets and liabilities and not to offset net derivative positions against 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	$ -	$ -	$ -	$ -
December 31, 2014				
Treasury derivatives	$ 33	$ -	$ -	$ 33

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 KU'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.

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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 KU'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.

At December 31, 2015, KU had no derivative contracts in a net liability position that contain credit risk-related contingent features.

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)	$ 145	$ 136	$ 145	$ 112
Land and transmission rights	14	1	14	1
Emission allowances (b)	2	-	2	-
OVEC power purchase agreement (c)	39	13	39	10
Total subject to amortization	$ 200	$ 150	$ 200	$ 123

(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.

Amortization expense was as follows:

	2015	2014
Intangible assets with regulatory offset	$ 27	$ 24

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Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2016	2017	2018	2019	2020
Intangibles with regulatory offset	$ 13	$ 3	$ 3	$ 3	$ 2

15. Asset Retirement Obligations

KU's AROs are primarily related to the final retirement of assets associated with generating units. KU'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. KU'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	$ 211	$ 178
Accretion expense	13	10
Obligations incurred	2	1
Changes in estimated cash flow or settlement date	136	22
Obligations settled	(2)	-
ARO at end of period	$ 360	$ 211

KU recorded increases of $139 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, KU had $25 million of the ARO balances classified as current liabilities. These 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 4 for information on the rate recovery applications with the KPSC.

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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. KU expects to adopt this guidance effective January 1, 2018.

KU 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	$ (84)	$ -
Interest on borrowed money	73	73
Other cash paid for interest	2	-

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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				674,799
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(441,491)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(441,491)
5	Balance of Account 219 at End of Preceding Quarter/Year				233,308
6	Balance of Account 219 at Beginning of Current Year				233,308
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				(520,708)
9	Total (lines 7 and 8)				(520,708)
10	Balance of Account 219 at End of Current Quarter/Year				(287,400)

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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			674,799	[redacted]	[redacted]
2			(441,491)	[redacted]	[redacted]
3				[redacted]	[redacted]
4			(441,491)	219,670,166	219,228,675
5			233,308	[redacted]	[redacted]
6			233,308	[redacted]	[redacted]
7				[redacted]	[redacted]
8			(520,708)	[redacted]	[redacted]
9			(520,708)	233,536,653	233,015,945
10			(287,400)	[redacted]	[redacted]

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FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 5 Column: e

See footnote data detail on Schedule Page: 112, Line No: 15, Column: d.

Schedule Page: 122(a)(b) Line No.: 10 Column: e

See footnote data detail on Schedule Page: 112, Line No: 15, Column: c.

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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)	7,232,591,744	7,232,591,744
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,581,756,561	1,581,756,561
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,814,348,305	8,814,348,305
9	Leased to Others		
10	Held for Future Use	633,629	633,629
11	Construction Work in Progress	267,026,968	267,026,968
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,082,008,902	9,082,008,902
14	Accum Prov for Depr, Amort, & Depl	2,849,851,989	2,849,851,989
15	Net Utility Plant (13 less 14)	6,232,156,913	6,232,156,913
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,805,424,466	2,805,424,466
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	44,427,523	44,427,523
22	Total In Service (18 thru 21)	2,849,851,989	2,849,851,989
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,849,851,989	2,849,851,989

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
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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	44,456	
3	(302) Franchises and Consents	55,919	
4	(303) Miscellaneous Intangible Plant	81,730,955	13,332,197
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	81,831,330	13,332,197
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	22,132,184	826,019
9	(311) Structures and Improvements	329,727,558	12,416,578
10	(312) Boiler Plant Equipment	3,424,226,285	444,966,025
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	341,075,242	7,300,734
13	(315) Accessory Electric Equipment	219,188,982	5,512,199
14	(316) Misc. Power Plant Equipment	38,748,615	-57,573
15	(317) Asset Retirement Costs for Steam Production	189,316,235	156,761,426
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,564,415,101	627,725,408
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	879,312	
28	(331) Structures and Improvements	832,090	
29	(332) Reservoirs, Dams, and Waterways	21,850,674	34,972
30	(333) Water Wheels, Turbines, and Generators	13,732,503	326,393
31	(334) Accessory Electric Equipment	1,321,689	
32	(335) Misc. Power PLant Equipment	287,615	35,297
33	(336) Roads, Railroads, and Bridges	176,359	58,150
34	(337) Asset Retirement Costs for Hydraulic Production	388,627	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	39,468,869	454,812
36	D. Other Production Plant		
37	(340) Land and Land Rights	298,979	12,529
38	(341) Structures and Improvements	35,917,793	47,155,135
39	(342) Fuel Holders, Products, and Accessories	25,353,098	134,697,033
40	(343) Prime Movers	377,573,343	98,695,789
41	(344) Generators	59,351,588	113,157,352
42	(345) Accessory Electric Equipment	46,828,218	26,734,652
43	(346) Misc. Power Plant Equipment	5,513,148	142,460
44	(347) Asset Retirement Costs for Other Production		403,344
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	550,836,167	420,998,294
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,154,720,137	1,049,178,514

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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
			44,456		2
			55,919		3
2,808,226			92,254,926		4
2,808,226			92,355,301		5
					6
					7
			22,958,203		8
4,544,930			337,599,206		9
80,148,519			3,789,043,791		10
					11
19,328,847			329,047,129		12
3,288,677			221,412,504		13
2,425,523			36,265,519		14
16,856,226			329,221,435		15
126,592,722			5,065,547,787		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			879,312		27
4,488			827,602		28
			21,885,646		29
			14,058,896		30
			1,321,689		31
5,964			316,948		32
			234,509		33
	-114,317		274,310		34
10,452	-114,317		39,798,912		35
					36
			311,508		37
			83,072,928		38
			160,050,131		39
2,454,814			473,814,318		40
			172,508,940		41
21,022			73,541,848		42
			5,655,608		43
			403,344		44
2,475,836			969,358,625		45
129,079,010	-114,317		6,074,705,324		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	31,698,598	90,667
49	(352) Structures and Improvements	24,580,511	1,022,887
50	(353) Station Equipment	262,460,425	10,735,219
51	(354) Towers and Fixtures	76,689,332	-223,860
52	(355) Poles and Fixtures	201,062,896	28,464,159
53	(356) Overhead Conductors and Devices	169,922,792	9,065,272
54	(357) Underground Conduit	448,760	
55	(358) Underground Conductors and Devices	1,161,309	11,994
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	413,450	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	768,438,073	49,166,338
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,842,857	
61	(361) Structures and Improvements	9,872,191	872,500
62	(362) Station Equipment	165,674,565	8,815,154
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	340,325,998	17,271,799
65	(365) Overhead Conductors and Devices	325,059,771	20,165,219
66	(366) Underground Conduit	1,959,407	91,114
67	(367) Underground Conductors and Devices	170,076,602	12,273,339
68	(368) Line Transformers	301,864,288	8,444,371
69	(369) Services	94,804,779	188,484
70	(370) Meters	74,754,582	2,927,987
71	(371) Installations on Customer Premises	18,140,553	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	95,796,869	6,912,824
74	(374) Asset Retirement Costs for Distribution Plant	911,173	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,607,083,635	77,962,791
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	2,814,999	27
87	(390) Structures and Improvements	53,190,061	4,968,045
88	(391) Office Furniture and Equipment	43,434,589	12,778,834
89	(392) Transportation Equipment	16,483,480	155,316
90	(393) Stores Equipment	905,832	598,594
91	(394) Tools, Shop and Garage Equipment	11,018,155	1,137,144
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	2,261,006	32,194
94	(397) Communication Equipment	44,824,444	6,978,080
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	174,932,566	26,648,234
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)	174,932,566	26,648,234
100	TOTAL (Accounts 101 and 106)	7,787,005,741	1,216,288,074
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)	7,787,005,741	1,216,288,074

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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
			31,789,265		48
95,707			25,507,691		49
9,189,232		297,286	264,303,698		50
62,173			76,403,299		51
727,209			228,799,846		52
445,350			178,542,714		53
			448,760		54
			1,173,303		55
					56
			413,450		57
10,519,671		297,286	807,382,026		58
					59
			7,842,857		60
25,894			10,718,797		61
968,407		-292,555	173,228,757		62
					63
2,800,557			354,797,240		64
7,282,615		-4,731	337,937,644		65
			2,050,521		66
956,280			181,393,661		67
2,254,659			308,054,000		68
117,895			94,875,368		69
354,193			77,328,376		70
1,086,462			17,054,091		71
					72
6,711,870			95,997,823		73
3,477			907,696		74
22,562,309		-297,286	1,662,186,831		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
4,944			2,810,082		86
953,087			57,205,019		87
11,772,883			44,440,540		88
11,062,452			5,576,344		89
			1,504,426		90
8,400			12,146,899		91
					92
			2,293,200		93
60,211			51,742,313		94
					95
23,861,977			177,718,823		96
					97
					98
23,861,977			177,718,823		99
188,831,193	-114,317		8,814,348,305		100
					101
					102
					103
188,831,193	-114,317		8,814,348,305		104

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 14 Column: c

Amounts temporarily classified to plant account Miscellaneous 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.: 34 Column: e

Adjustment due to changes in asset retirement cost estimates.

Schedule Page: 204 Line No.: 51 Column: c

Amounts temporarily classified to plant account Towers and Fixtures (354) 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
Kentucky Utilities 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	Pennington Gap Substation #2	8/1/2013	2019-2020	324,088
3	Land at Green River Facility	11/1/2014	2021	309,541
4				
5				
6				
7				
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9				
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21	Other Property:			
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47	Total			633,629

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	BROWN LANDFILL PHASE I	107,142,012
3	GHENT LANDFILL PHASE IB	9,785,792
4	TC CCP LANDFILL PH1 RAVINE - KU	8,524,979
5	GHENT ASH POND/LANDFILL	4,673,059
6	TC2 DRY SORBENT INJECTION SYSTEM - KU	4,261,039
7	GH3 FABRIC FILTER	2,902,012
8	GENERATOR STEP UP GE 345KV SPARE - KU	2,446,753
9	GH4 FABRIC FILTER	2,264,895
10	STEAM PRODUCTION MINOR	16,516,132
11		
12	HYDRAULIC POWER MAJOR	
13	DIX DAM HYDRO BUILDING REFURBISHMENT	1,888,157
14	HYDRAULIC POWER MINOR	252,704
15		
16	OTHER PRODUCTION MAJOR	
17	BROWN SOLAR FACILITY - KU	6,399,373
18	CANE RUN 7 NATURAL GAS COMBINED CYCLE SPARES - KU	3,817,726
19	OTHER PRODUCTION MINOR	2,334,842
20		
21	TRANSMISSION MAJOR	
22	MATANZAS TRANSMISSION SUBSTATION UPGRADE	12,630,233
23	PRIORITY REPLACEMENT TRANSMISSION LINES	7,826,778
24	RELOCATE - PARKERS MILL 604 BREAKER ADDITION	2,071,487
25	KU PARK CONTROL HOUSE	1,616,820
26	TEP - FARLEY SWEET HOLLOW US STEEL 69KV	1,450,455
27	POLE REPLACEMENT P2 - HARDIN CO SMITH 345KV	1,395,530
28	POLE REPLACEMENT - PRINCETON CRITTENDEN CO	1,252,076
29	TRANSMISSION SYSTEM PROACTIVE REPLACEMENTS	1,250,937
30	LEXINGTON AREA MAJOR SUBSTATION PROJECT	1,183,409
31	NERC RATINGS PROJECT - BROWN FAWKES 138KV	1,090,764
32	KU RTU REPLACEMENTS	1,031,606
33	HIGBY MILL - KY RIVER P2	1,009,970
34	TYRONE TRANSMISSION CONTROL HOUSE	1,003,791
35	TRANSMISSION MINOR	10,596,198
36		
37	DISTRIBUTION MAJOR	
38	LEXINGTON AREA MAJOR PROJECT	1,650,874
39	LEXINGTON AREA MAJOR SUBSTATION PROJECT	1,517,345
40	POLE INSPECTION AND REPLACEMENT PROJECT - PINEVILLE	1,491,073
41	N-1 DISTRIBUTION TRANSFORMER ENHANCEMENT - LAKESHORE SUBSTATION	1,419,115
42	PURCHASE DISTRIBUTION BUCKET TRUCKS - KU	1,358,505
43	TOTAL	267,026,968

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	DELAPLAIN TRANSFORMER UPGRADE	1,281,418
2	POLE INSPECTION AND REPLACEMENT PROJECT - ELIZABETHTOWN	1,161,895
3	AIRPORT/KEENELAND RELIABILITY	1,128,199
4	KU MAJOR STORMS	1,094,814
5	DISTRIBUTION MINOR	23,960,993
6		
7	GENERAL MAJOR	
8	OPTICAL TRANSPORT NETWORK CORE RINGS	1,700,423
9	VENTYX MOBILE UPGRADE4	1,570,735
10	PEOPLESOFT TIME KEEPING SYSTEM	1,440,715
11	SOUTH EAST KY ALTERNATE TRANSPORT TELECOM BUILDOUT	1,180,331
12	GENERAL MINOR	6,451,004
13		
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41		
42		
43	TOTAL	267,026,968

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	2,762,597,300	2,762,597,300		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	209,271,260	209,271,260		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	531,728	531,728		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	732,022	732,022		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	210,535,010	210,535,010		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	169,163,264	169,163,264		
13	Cost of Removal	24,192,378	24,192,378		
14	Salvage (Credit)	1,203,409	1,203,409		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	192,152,233	192,152,233		
16	Other Debit or Cr. Items (Describe, details in footnote):	41,304,092	41,304,092		
17					
18	Book Cost or Asset Retirement Costs Retired	-16,859,703	-16,859,703		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,805,424,466	2,805,424,466		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,515,970,573	1,515,970,573		
21	Nuclear Production				
22	Hydraulic Production-Conventional	10,701,471	10,701,471		
23	Hydraulic Production-Pumped Storage				
24	Other Production	248,160,618	248,160,618		
25	Transmission	332,446,842	332,446,842		
26	Distribution	638,252,808	638,252,808		
27	Regional Transmission and Market Operation				
28	General	59,892,154	59,892,154		
29	TOTAL (Enter Total of lines 20 thru 28)	2,805,424,466	2,805,424,466		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: c

Accrual for Depreciation on Asset Retirement Costs - (Other Regulatory Assets FERC 182.3)	$	40,812,373
Customer Payments Related to Construction Projects		491,719
Total Other Debit or Credit Items	$	41,304,092

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 (2.50%)			
2	Common Stock, $100 par value, 2,500 shares			
3	250 shares	11/15/52		25,000
4	250 shares	01/14/53		25,000
5	250 shares	03/04/53		25,000
6	250 shares	04/15/53		25,000
7	250 shares	05/20/53		25,000
8	250 shares	06/22/53		25,000
9	500 shares	07/15/53		50,000
10	500 shares	07/31/53		50,000
11				
12	EEI (20%)			
13	Common Stock, $100 par value, 12,400 shares			
14	3,500 shares	03/06/51		
15	2,700 shares	08/03/53		
16	6,200 shares	12/30/58		
17	Equity Earnings			
18	Other Comprehensive Income			
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42	Total Cost of Account 123.1 $ 250,000		TOTAL	250,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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
		25,000		3
		25,000		4
		25,000		5
		25,000		6
		25,000		7
		25,000		8
		50,000		9
		50,000		10
				11
				12
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				41
		250,000		42

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Name of Respondent Kentucky Utilities 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: 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.

Schedule Page: 224 Line No.: 12 Column: a

EEI was fully impaired in 2012 which reduced the balance in Invesment in Subsidiary Companies (123.1) to zero, the estimated fair value at December 31, 2012. See Note 1 of Notes to Financial Statements under Equity Method Investment for a full description of the EEI investment.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	99,282,056	97,051,051	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)	27,661,154	28,838,047	Electric
8	Transmission Plant (Estimated)	4,246,528	5,816,467	Electric
9	Distribution Plant (Estimated)	6,747,834	6,528,708	Electric
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)	38,655,516	41,183,222	
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)	10,574,016	9,371,630	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	148,511,588	147,605,903	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	169,751.00	156,701	77,535.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	77,535.00			
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	25,794.00	16,345		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	221,492.00	140,356	77,535.00	
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	1,106.50		1,106.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,106.50			
40	Balance-End of Year			1,106.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,106.50	123		
45	Gains		123		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 No. (f)	2017 Amt. (g)	2018 No. (h)	2018 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
77,535.00		77,535.00		2,015,910.00		2,418,266.00	156,701	1
								2
								3
						77,535.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						25,794.00	16,345	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
77,535.00		77,535.00		2,015,910.00		2,470,007.00	140,356	29
								30
								31
								32
								33
								34
								35
1,106.50		1,106.50		54,218.50		58,644.50		36
								37
								38
				1,106.50		2,213.00		39
1,106.50		1,106.50		53,112.00		56,431.50		40
								41
								42
								43
				1,106.50	33	2,213.00	156	44
					33		156	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	473.00	2,171		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	21,986.00		21,783.00	
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	17,337.00	1,883		
19	Other:				
20	Charges to Account 549	597.00	288		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	4,525.00		21,783.00	
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
Kentucky Utilities 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.
						473.00	2,171	1
								2
								3
						43,769.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						17,337.00	1,883	18
								19
						597.00	288	20
								21
								22
								23
								24
								25
								26
								27
								28
						26,308.00		29
								30
								31
								32
								33
								34
								35
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	3,728	561.6	3,728	561.6
3	Facility Studies	831	561.6	831	561.6
4					
5					
6					
7					
8					
9					
10					
11					
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14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	System Impact Studies	201	561.6	201	561.6
23	Facility Studies	2,126	561.6	2,126	561.6
24					
25					
26					
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39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	ASC 715 - Pension and Postretirement	132,968,229	12,508,031	Various	24,770,247	120,706,013
2	Asset Retirement Obligation	50,755,698	54,140,172	Various	19,201,691	85,694,179
3	ASC 740 - Income Taxes	70,465,029	1,420,946	282/283	1,924,923	69,961,052
4	Long-Term Interest Rate Swap Non-LKE Affiliate	33,287,299	10,604,071	Various	825,497	43,065,873
5	Winter Storm 2009 (Aug-10 to Jul-20)	31,957,190		571/593	5,723,675	26,233,515
6	Environmental Cost Recovery	803,000	11,590,000	440-445	1,337,000	11,056,000
7	Municipal Formula Rate True-Up		15,563,209	447	8,622,209	6,941,000
8	Green River Retirement (Jul-15 to Jun-18)		7,671,410	Various	1,213,788	6,457,622
9	Pension Gain/Loss Amortization - 15 Year		4,544,466	Various		4,544,466
10	Unamortized Debt Expense (Dec-05 to Feb-37) - PAA	3,562,038		181	195,280	3,366,758
11	2014 Rate Case Expenses (Jul-15 to Jun-18)	1,357,905	554,664	146/928	318,831	1,593,738
12	2012 Rate Case Expenses (Jan-13 to Dec-15)	551,491		928	551,491	
13	Mountain Storm 2009 (Nov-11 to Oct-16)	2,215,279		593	1,208,334	1,006,945
14	Wind Storm 2008 (Aug-10 to Jul-20)	1,225,830		593	219,552	1,006,278
15	MISO Exit Fee - FERC (Jul-14 to Jun-17)	1,208,048	77,758	182/575.7	563,539	722,267
16	Carbon Mgmt Research Group (Aug-10 to Jul-20)	162,197	224,440	146/930.2	224,440	162,197
17	KY Fuel Adjustment Clause	2,464,000		440-445	2,464,000	
18	Coal Contracts (Nov-10 to Dec-15) - PAA	221,692		253	221,692	
19	2011 General Mgmt Audit (Jan-13 to Dec-15)	47,507		928	47,507	
20						
21						
22						
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40						
41						
42						
43						
44	TOTAL	333,252,432	118,899,167		69,633,696	382,517,903

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	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.: 3 Column: a
The regulatory asset represents the future revenue impact from the reversal of deferred income tax liability required for a tax depreciation basis adjustment and allowance for funds used during construction.

Schedule Page: 232 Line No.: 4 Column: d
Accounts credited include 245, 254 and 427.

Schedule Page: 232 Line No.: 8 Column: d
Accounts credited include 408, 500-502, 505-506, 510-514, 925 and 926.

Schedule Page: 232 Line No.: 9 Column: d
Accounts credited include 182, 219, 232 and 926.

Schedule Page: 232 Line No.: 10 Column: a
Amounts in Unamortized Debt Expense (Dec-05 to Feb-37) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 232 Line No.: 18 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
Kentucky Utilities 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	607,404,368				607,404,368
2						
3	Key Man Life Insurance	38,795,593	1,845,085	131	6,510,737	34,129,941
4						
5	OVEC Power Purchase Contract					
6	(Nov-10 to Mar-26) - PAA	28,365,323		254	2,557,160	25,808,163
7						
8	Coal Contracts					
9	(Nov-10 to Dec-16) - PAA	33,649,953		254	23,544,432	10,105,521
10						
11	Cane Run 7 LTPC Asset		6,607,089			6,607,089
12						
13	Valuation of SO2 Allowances					
14	(Nov-10 to Dec-40) - PAA	1,667,702		254	223,417	1,444,285
15						
16	Customer Credit Accounts					
17	Receivable	128,505		142	951	127,554
18						
19	Cellular Antenna Billable Chgs		36,510			36,510
20						
21	Carrollton Sale/Leaseback					
22	(Aug-06 to Jul-23)	37,867		931	4,412	33,455
23						
24	Financing Expense		28,764			28,764
25						
26						
27						
28						
29						
30						
31						
32						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	710,049,311				685,725,650

Name of Respondent Kentucky Utilities 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: 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.: 6 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.: 9 Column: f

Amounts in Coal Contracts (Nov-10 to Dec-16) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 233 Line No.: 14 Column: f

Amounts in Valuation of SO2 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
Kentucky Utilities 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		97,475,988
3	Other Post Retirement & Employment Benefits	24,344,298	22,752,072
4	Regulatory Tax Adjustments	65,507,205	63,556,230
5	Interest Rate Swaps	29,059,154	15,552,684
6	Asset Retirement Obligation	82,066,110	140,873,792
7	Other - See Notes for Detail	45,269,839	31,995,746
8	TOTAL Electric (Enter Total of lines 2 thru 7)	246,246,606	372,206,512
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	506,584	508,135
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	246,753,190	372,714,647

Notes

	Bal. at Beg. of Year	Bal. at End of Year
VA Fuel Clause	$ 50,181	$ 718,483
Workers' Compensation	797,446	911,442
Environmental Cost Recovery	(312,367)	(4,300,784)
Vacation Pay	1,854,009	1,735,030
State Tax Adjustment	38,748	(177,801)
Bad Debt Reserve	940,444	712,652
Demand Side Management	573,726	1,863,460
Pensions	13,728,900	12,206,740
Air Permit Fees	1,136,679	633,412
Other	1,399,796	3,017,121
Total Line No. 7 Without Purchase Accounting	$ 20,207,562	$ 17,319,755
Purchase Accounting Adjustment	25,062,277	14,675,991
Total Line No. 7 With Purchase Accounting	$ 45,269,839	$ 31,995,746

	Bal. at Beg. of Year	Bal. at End of Year
Other Deductions	$ 506,584	$ 508,135
Total Line No. 17	$ 506,584	$ 508,135

Balance of Beginning of Year	$246,753,190
Less Debits to:	
Account 410.1	85,482,939
Account 410.2	100
Other Balance Sheet Accounts	1,950,974
Plus Credits to:	
Account 411.1	213,393,819
Account 411.2	1,651
Balance at End of Year	$372,714,647

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.

Note: Some beginning balance amounts were reordered from prior years' Form 1 ending balance amounts for 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
Kentucky Utilities 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	80,000,000		
3	Total Common	80,000,000		
4				
5	Preferred and Preference Stock			
6	Preferred Stock, Without Par Value	5,300,000		
7	Preference Stock, Without Par Value	2,000,000		
8	Total Preferred and Preference	7,300,000		
9				
10				
11				
12				
13				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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
37,817,878	308,139,978					2
37,817,878	308,139,978					3
						4
						5
						6
						7
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	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 KU is owned by its parent company, LKE.

Schedule Page: 250 Line No.: 8 Column: a

No shares of preferred or preference stock remain issued or outstanding.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	2,596,446,834
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40	TOTAL	2,596,446,834

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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
Kentucky Utilities 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	321,289
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22	TOTAL	321,289

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Mercer County 2000 Series A, due 05/01/2023, Variable	12,900,000	607,408
4	Carroll County 2002 Series A, due 02/01/2032, Variable	20,930,000	120,138
5	Carroll County 2002 Series B, due 02/01/2032, Variable	2,400,000	83,078
6	Carroll County 2002 Series C, due 10/01/2032, Variable	96,000,000	2,150,595
7	Mercer County 2002 Series A, due 02/01/2032, Variable	7,400,000	92,678
8	Muhlenberg County 2002 Series A, due 02/01/2032, Variable	2,400,000	93,078
9	Carroll County 2004 Series A, due 10/01/2034, Variable	50,000,000	1,483,449
10	Carroll County 2006 Series B, due 10/01/2034, Variable	54,000,000	1,315,275
11	Carroll County 2007 Series A, due 02/01/2026, 5.750%	17,875,000	638,428
12	Trimble County 2007 Series A, due 03/01/2037, 6.000%	8,927,000	471,138
13	Carroll County 2008 Series A, due 02/01/2032, Variable	77,947,405	798,036
14			
15	First Mortgage Bonds:		
16	2010 due 11/01/2015, 1.625%	250,000,000	2,261,768
17			875,000 D
18	2010 due 11/01/2020, 3.250%	500,000,000	4,156,684
19			1,890,000 D
20	2010 due 11/01/2040, 5.125%	750,000,000	7,480,434
21			8,137,500 D
22	2013 due 11/15/2043, 4.650%	250,000,000	2,773,770
23			1,800,000 D
24	2015 due 10/1/2025, 3.300% (Case No.2014-00082 June 16, 2014)	250,000,000	2,013,760
25			107,500 D
26	2015 due 10/1/2045, 4.375% (Case No.2014-00082 June 16, 2014)	250,000,000	2,576,260
27			207,500 D
28	TOTAL ACCOUNT 221	2,600,779,405	42,133,477
29			
30	ACCOUNT 223:		
31	TOTAL ACCOUNT 223		
32			
33	TOTAL	2,601,940,860	42,133,477

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	AMORTIZATION PERIOD 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	05/01/2023	05/19/2000	05/01/2023	12,900,000	5,006	3
05/23/2002	02/01/2032	05/23/2002	02/01/2032	20,930,000	61,528	4
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	7,055	5
10/03/2002	10/01/2032	10/03/2002	10/01/2032	96,000,000	235,248	6
05/23/2002	02/01/2032	05/23/2002	02/01/2032	7,400,000	21,918	7
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	7,109	8
10/20/2004	10/01/2034	10/20/2004	10/01/2034	50,000,000	16,683	9
02/23/2007	10/01/2034	02/23/2007	10/01/2034	54,000,000	19,063	10
05/24/2007	02/01/2026	05/24/2007	02/01/2026	17,875,000	1,027,812	11
05/24/2007	03/01/2037	05/24/2007	03/01/2037	8,927,000	535,621	12
10/17/2008	02/01/2032	10/17/2008	02/01/2032	77,947,405	26,649	13
						14
						15
11/16/2010	11/01/2015	11/16/2010	11/01/2015		3,385,417	16
						17
11/16/2010	11/01/2020	11/16/2010	11/01/2020	500,000,000	16,250,000	18
						19
11/16/2010	11/01/2040	11/16/2010	11/01/2040	750,000,000	38,437,500	20
						21
11/14/2013	11/15/2043	11/14/2013	11/15/2043	250,000,000	10,191,296	22
	11/15/2043					23
09/28/2015	10/1/2025	09/28/2015	10/01/2025	250,000,000	2,497,034	24
	10/1/2025					25
09/28/2015	10/1/2045	09/28/2015	10/1/2045	250,000,000	3,082,166	26
	10/1/2045					27
				2,350,779,405	75,807,105	28
						29
						30
						31
						32
				2,351,148,921	75,653,843	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 224:		
2	Purchase Accounting Adjustments for Fair Value Measurement:		
3	Carroll County 2007 Series A, due 02/01/2026, 5.750%	804,375	
4	Trimble County 2007 Series A, due 03/01/2037, 6.000%	357,080	
5	TOTAL ACCOUNT 224	1,161,455	
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32			
33	TOTAL	2,601,940,860	42,133,477

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
		11/01/2010	06/01/2018	255,911	-106,143	3
		11/01/2010	06/01/2018	113,605	-47,119	4
				369,516	-153,262	5
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				2,351,148,921	75,653,843	33

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Name of Respondent Kentucky Utilities 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: 256 Line No.: 1 Column: a

Per instruction 9 concerning the treatment of unamortized debt expense, premium or discount, debt premium and expenses are being amortized over the lives of the related issues.

Schedule Page: 256 Line No.: 2 Column: a

Pollution control series bonds are obligations of KU, issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU 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.: 15 Column: a

Proceeds from KU’s First Mortgage Bonds issued in 2010 were used to repay the loans from a PPL subsidiary and for general corporate purposes. Proceeds from KU's First Mortgage Bonds issued in 2013 were used for capital expenditures and general corporate purposes. Proceeds from KU’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.: 24 Column: a

By Order in Case No. 2014-00082 on June 16, 2014, KU was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $500 million and enter into hedging agreements to lock in interest rates for debt to be issued in 2015. KU entered into hedging agreements totaling $250 million for the 10 year bond and $250 million for the 30 year bond. Debt was issued in September 2015, totaling $250 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 $250 million, 10 year First Mortgage Bonds.

Schedule Page: 256 Line No.: 26 Column: a

By Order in Case No. 2014-00082 on June 16, 2014, KU was authorized by the KPSC to issue First Mortgage Bonds in aggregate principal amount of up to $500 million and enter into hedging agreements to lock in interest rates for debt to be issued in 2015. KU entered into hedging agreements totaling $250 million for the 10 year bond and $250 million for the 30 year bond. Debt was issued in September 2015, totaling $250 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 Line No.: 30 Column: a

KU did not have long-term notes with associated companies in 2015.

Schedule Page: 256.1 Line No.: 1 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 fair values on the acquisition date.

The following pollution control bonds with coupon rates, listed below, were fair valued and continue to be amortized as a result of the PPL acquisition:

Bond Issue	(221) Principal	(224) Fair Value Adjustment	Total Purchase Accounting
Carroll County 2007 Series A, due 2/1/2026, 5.750%	$17,875,000	$ 804,375	$18,679,375
Trimble County 2007 Series A, due 3/1/2037, 6.000%	$ 8,927,000	$ 357,080	$ 9,284,080

The purchase accounting adjustments were recorded to Other Long-Term Debt (224). Amortization is recorded to Interest on Long-Term Debt (427).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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)	233,536,653
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	18,434,518
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote	476,440,172
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote	12,348,962
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote	776,359,794
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-60,297,413
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	
31	35% Rounded	-21,104,095
32	Add: Adjustments to Prior Years' Taxes to Actual and Other	418,777
33		
34	Total	-20,685,318
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Contributions in Aid of Construction	$ 4,251,518
Fuel Adjustment Clause KY	14,183,000
Total	$ 18,434,518

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Provision for Deferred Taxes	$ 161,717,218
Demand Side Management	3,315,514
Over/Under Collections - VA Fuel Clause	1,718,000
Capitalized Interest	16,357,644
Net Operating Loss	278,502,822
Pensions	2,221,023
Obsolete Inventory	1,500,000
Amortization of Regulatory Expenses	315,658
MISO Exit Fees - Transmission	153,238
Non-Deductible Expenses	803,850
Amortization Loss on Reacquired Debt	683,508
Storm Damages	7,151,561
Workers Compensation	293,048
Performance Incentive	1,479,924
Other	227,164
Total	$ 476,440,172

Schedule Page: 261 Line No.: 15 Column: b

Environmental Cost Recovery	$ 10,253,000
Customer Advances for Construction	249,760
Amortization of Investment Tax Credit	1,846,202
Total	$ 12,348,962

Schedule Page: 261 Line No.: 20 Column: b

Federal Income Taxes:	
Other Income and Deductions	$ 1,231,898
Utility Operating Income	19,453,420
Tax Over Book Depreciation, Net and Repairs	658,724,022
Interest Rate Swaps	44,499,577
EEI Investment	852,222
Cost of Removal	25,059,748
Contingent Liabilities	1,293,746
Postemployment	573,653
Postretirement	2,487,601
Green River Regulatory Asset	6,457,622
Muni True-Up Regulatory Asset	9,659,099
Vacation Pay	181,249
Current State Income Tax	618,711
Life Insurance	3,200,973
AFUDC Flow Through	987,405
Bad Debt Reserve	585,623
Other	339,963
Total Without Purchase Accounting	$ 776,206,532
Purchase Accounting Adjustments - FMV Bonds	153,262
Total	$ 776,359,794

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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			-80,427,777	-85,920,209	
3	FICA	736,600		6,802,042	6,857,698	
4						
5	Kentucky:					
6	Income	110,709		1,436,933	1,547,642	
7	Public Service Commission		1,462,487	2,951,355	2,977,735	
8	Use	521,703		5,769,878	5,617,012	
9						
10	Federal & Kentucky:					
11	Unemployment Insurance	189,828		74,513	245,594	
12						
13	Kentucky & Virginia:					
14	Property Taxes	12,415,199		25,918,031	24,775,475	
15	Miscellaneous			62,829	62,829	
16						
17	Use (Virginia)			16,173	13,063	
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	13,974,039	1,462,487	-37,396,023	-43,823,161	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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				
(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)	Line No.
						1
5,492,432		-19,453,420			-60,974,357	2
680,944		9,348,184			-2,546,142	3
						4
						5
		1,153,593			283,340	6
	1,488,867	2,951,355				7
674,569		34,857			5,735,021	8
						9
						10
18,747		222,990			-148,477	11
						12
						13
13,557,755		25,680,955			237,076	14
		62,829				15
						16
3,110					16,173	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
20,427,557	1,488,867	20,001,343			-57,397,366	41

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

Segregation of Other	Other (l)	Page 117 Other Inc & Deductions 408.2 - 409.2	Other Accounts
Federal:			
Income	$ (60,974,357)	$ (1,231,898)	$ (59,742,459)
FICA	(2,546,142)	-	(2,546,142)
Kentucky:			
Income	283,340	(224,662)	508,002
6% Use	5,735,021	-	5,735,021
Federal & Kentucky:			
Unemployment Ins	(148,477)	-	(148,477)
Kentucky & Virgina:			
Property Taxes	237,076	10,827	226,249
Use (Virginia)	16,173	-	16,173
Total	$ (57,397,366)	$ (1,445,733)	$ (55,951,633)

Reconciliation to Schedule Page: 114, Line No.: 14, Column: c

Other:	
Electric Total	$ 20,001,343
Less Federal	19,453,420
Less State	(1,153,593)
Total	$ 38,301,170

Schedule Page: 262 Line No.: 2 Column: b

Balance at Beginning of Year totaling $59,742,459 was reclassified to Accounts Receivable from Associated Companies (146).

Schedule Page: 262 Line No.: 5 Column: a

Balance at End of Year totaling $508,002 was reclassified to Income Tax Receivable-State (143).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	15%	92,305,369			420	1,775,102	
7	Various	2,559,771			420	71,100	
8	TOTAL	94,865,140				1,846,202	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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
90,530,267	54 years		6
2,488,671	41 years		7
93,018,938			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	34,476,493	232	27,475,347		7,001,146
2						
3	Corporate Headquarters Lease					
4	(Jul-12 to Dec-25)	1,242,566			47,770	1,290,336
5						
6	Uncertain Tax Position - Federal	304,929				304,929
7						
8	Deferred Rent Payable					
9	(Aug-06 to Jul-23)	45,088	931	5,255		39,833
10						
11	Carrollton Sale/Leaseback					
12	(Aug-06 to Jul-23)	37,604	421.1	4,381		33,223
13						
14	Deferred Compensation	6,473			3,989	10,462
15						
16	Brown CT Long-Term Service					
17	Agreement	2,326,851	107/232/553	2,326,851		
18						
19	Valuation of Coal Contracts					
20	(Nov-10 to Dec-15) - PAA	221,692	182.3	221,692		
21						
22	Deferred Swaps Revenue	55,000	447	62,000	7,000	
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
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40						
41						
42						
43						
44						
45						
46						
47	TOTAL	38,716,696		30,095,526	58,759	8,679,929

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	983,763,085	407,990,001	120,354,947
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	983,763,085	407,990,001	120,354,947
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	983,763,085	407,990,001	120,354,947
10	Classification of TOTAL			
11	Federal Income Tax	872,762,460	368,535,415	104,561,318
12	State Income Tax	111,000,625	39,454,586	15,793,629
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
		182/254	1,391,146	182/254	2,301,397	1,272,308,390	2
							3
							4
			1,391,146		2,301,397	1,272,308,390	5
							6
							7
							8
			1,391,146		2,301,397	1,272,308,390	9
							10
			1,215,237		1,732,848	1,137,254,168	11
			175,909		568,549	135,054,222	12
							13

NOTES (Continued)

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	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 $62,322,144.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2014, is $(35,027,491).

Schedule Page: 274 Line No.: 2 Column: k

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2015, is $107,538,757.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2015, is $(35,937,742).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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	Regulatory Tax Adjustments	27,410,897		
4	Interest Rate Swaps	12,948,759	16,971,292	13,167,426
5	Asset Retirement Obligation	19,743,967	14,324,777	733,708
6	Pension - Regulatory Asset	41,379,712	4,133,311	6,535,075
7	Casualty Loss - Storm Damages	13,769,940	150,183	2,932,140
8	Other	30,129,777	8,958,211	19,506,344
9	TOTAL Electric (Total of lines 3 thru 8)	145,383,052	44,537,774	42,874,693
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other			
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	145,383,052	44,537,774	42,874,693
20	Classification of TOTAL			
21	Federal Income Tax	122,958,930	38,325,121	36,918,557
22	State Income Tax	22,424,122	6,212,653	5,956,136
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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					
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
							2
		182/254	748,796	182/254	552,748	27,214,849	3
						16,752,625	4
						33,335,036	5
						38,977,948	6
						10,987,983	7
						19,581,644	8
			748,796		552,748	146,850,085	9
							10
							11
							12
							13
							14
							15
							16
							17
726,277	394,763	219	726,105	219	394,591		18
726,277	394,763		1,474,901		947,339	146,850,085	19
							20
622,680	342,299		1,265,614		819,424	124,199,685	21
103,597	52,464		209,287		127,915	22,650,400	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	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 KU by PPL in November 2010. The following reflects the balance at December 31, 2014:

Rate Case Expenses	$ 742,755
FAC Over/Under-Recovery	958,495
MISO Exit Fees	(346,320)
Other	123,335
Emission Allowances	61,799
Loss on Reacquired Debt	3,730,798

Total for Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$ 5,270,862
Purchase Accounting Adjustment	24,858,915

Total for Accumulated Deferred Income Taxes - Other (283)	$ 30,129,777

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 KU 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:	
Rate Case Expenses	$ 97,465
FAC Over/Under-Recovery	2,069,825
MISO Exit Fees	498,518
Other	225,247
Emission Allowances	1,886
Loss on Reacquired Debt	14,354
Green River Regulatory Asset	2,647,625
Muni True-Up Regulatory Asset	2,845,810

Total for Amounts Debited to Account 410.1 Without Purchase Accounting	$ 8,400,730
Purchase Accounting Adjustment	557,481

Total for Amounts Debited to Account 410.1	$ 8,958,211

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 KU 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:	
Rate Case Expenses	$ 220,256
FAC Over/Under-Recovery	7,587,012
MISO Exit Fees	88,197
Other	156,033
Emission Allowances	9,089
Loss of Reacquired Debt	280,239
Green River Regulagtory Asset	135,610
Muni True-Up Regulatory Asset	145,761

Total for Amounts Credited to Account 411.1 Without Purchase Accounting	$ 8,622,197
Purchase Accounting Adjustment	10,884,147

Total for Amounts Credited to Account 411.1	$ 19,506,344

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: k

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of KU by PPL in November 2010. The following reflects the balance at December 31, 2015:

Rate Case Expenses	$ 619,964
FAC Over/Under-Recovery	(4,558,692)
MISO Exit Fees	64,001
Other	192,549
Emission Allowances	54,596
Loss on Reacquired Debt	3,464,913
Green River Regulatory Asset	2,512,015
Muni True-Up Regulatory Asset	2,700,049

Total for Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$ 5,049,395
Purchase Accounting Adjustment	14,532,249

Total for Accumulated Deferred Income Taxes - Other (283)	$ 19,581,644

Schedule Page: 276 Line No.: 18 Column: e

Amounts Debited to Account 410.2:

EEI Investment	$ 726,277

Schedule Page: 276 Line No.: 18 Column: f

Amounts Credited to Account 411.2:

EEI Investment	$ 394,763

Schedule Page: 276 Line No.: 18 Column: h

Debit Adjustments:

OCI EEI Investment	$ 726,105

Schedule Page: 276 Line No.: 18 Column: j

Credit Adjustments:

OCI EEI Investment	$ 394,591

Schedule Page: 276 Line No.: 19 Column: b

A minor beginning balance reclassification was made between the Regulatory Tax Adjustment and the Other section from prior year’s Form 1 ending balances for 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
Kentucky Utilities 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	ASC 740 - Income Taxes	73,533,848	190/282	3,530,069	360,912	70,364,691
2	Forward Starting Swap	41,414,897	427	1,433,703		39,981,194
3	OVEC Pwr Purchase Contract (Nov-10 to Mar-26)-PAA	28,365,322	186	2,557,160		25,808,162
4	ASC 715 - Pension and Postretirement	15,914,251	184/228	543,942	8,645,966	24,016,275
5	KY Fuel Adjustment Clause		440-445	1,071,887	12,790,887	11,719,000
6	Coal Contracts (Nov-10 to Dec-16) - PAA	33,649,953	186	23,544,432		10,105,521
7	DSM Cost Recovery	1,474,872	440-445	6,817,464	10,132,978	4,790,386
8	VA Fuel Component	108,000	440-445	12,000	1,550,000	1,646,000
9	Emission Allowances (Nov-10 to Dec-40) - PAA	1,667,702	186	420,881	197,464	1,444,285
10	MISO Exit Fee Refund - Kentucky	828,345	143/575.7	329,407		498,938
11	MISO Exit Fee Refund - FERC (Jun-14 to May-17)	54,393	143/575.7	2,021		52,372
12	MISO Exit Fee Refund - Virginia	7,549	143/575.7	72,068	70,954	6,435
13	VA Fuel Component - Non-Jurisdictional	21,000	440-445		180,000	201,000
14	Off-System Sales Tracker		440-445	173,183	287,789	114,606
15	Long-Term Interest Rate Swap Non-LKE Affiliate	23,617	182.3/147	23,617		
16	Muni Generation True Up	2,718,099	447	7,406,435	4,688,336	
17						
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	199,781,848		47,938,269	38,905,286	190,748,865

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 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.: 3 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.: 6 Column: a

Amounts in Coal Contracts (Nov-10 to Dec-16) - PAA are purchase accounting adjustments (PAA) only.

Schedule Page: 278 Line No.: 9 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
Kentucky Utilities 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	611,903,176	631,062,022
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	379,981,601	381,624,816
5	Large (or Ind.) (See Instr. 4)	429,469,775	433,328,131
6	(444) Public Street and Highway Lighting	11,659,583	11,417,588
7	(445) Other Sales to Public Authorities	128,411,369	127,593,749
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,561,425,504	1,585,026,306
11	(447) Sales for Resale	143,406,275	126,825,129
12	TOTAL Sales of Electricity	1,704,831,779	1,711,851,435
13	(Less) (449.1) Provision for Rate Refunds	3,840,132	2,700,607
14	TOTAL Revenues Net of Prov. for Refunds	1,700,991,647	1,709,150,828
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,012,449	3,898,511
17	(451) Miscellaneous Service Revenues	2,123,872	2,178,769
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	3,795,101	3,703,543
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	261,073	687,191
22	(456.1) Revenues from Transmission of Electricity of Others	17,876,191	17,580,812
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	28,068,686	28,048,826
27	TOTAL Electric Operating Revenues	1,729,060,333	1,737,199,654

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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
6,368,650	6,740,813	447,671	445,877	2
				3
3,996,049	4,071,635	83,784	83,671	4
7,009,767	7,235,685	3,054	3,011	5
43,500	43,639	1,474	1,438	6
1,628,429	1,632,876	8,324	8,230	7
				8
				9
19,046,395	19,724,648	544,307	542,227	10
2,763,736	2,262,210	23	22	11
21,810,131	21,986,858	544,330	542,249	12
				13
21,810,131	21,986,858	544,330	542,249	14

Line 12, column (b) includes $ -18,810,534 of unbilled revenues.
Line 12, column (d) includes -167,343 MWH relating to unbilled revenues

BLANK

Name of Respondent Kentucky Utilities 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: 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	$ 5,482,212
2015 invoices to East Kentucky Power Cooperative	4,633,070
2015 invoices to Kentucky Municipal Power Agency	1,791,868
2015 invoices to City of Frankfort	1,539,041
2015 invoices to Tennessee Valley Authority	891,638
2015 invoices to City of Madisonville	643,431
2015 invoices to Louisville Gas and Electric Company	563,285
2015 invoices to City of Nicholasville	434,279
2015 invoices to City of Bardstown	422,143
2015 invoices to City of Berea	305,070
Other items less than $250,000 each	1,170,154
Total for Revenues from Transmission of Electricity of Others (456.1)	$ 17,876,191

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	$ 4,987,933
2014 invoices to East Kentucky Power Cooperative	4,816,576
2014 invoices to Kentucky Municipal Power Agency	1,676,483
2014 invoices to City of Frankfort	1,464,198
2014 invoices to Louisville Gas and Electric Company	1,072,045
2014 invoices to Tennessee Valley Authority	1,036,047
2014 invoices to City of Madisonville	547,649
2014 invoices to City of Nicholasville	411,097
2014 invoices to City of Bardstown	393,132
2014 invoices to City of Berea	289,845
Other items less than $250,000 each	885,807
Total for Revenues from Transmission of Electricity of Others (456.1)	$ 17,580,812

Schedule Page: 300 Line No.: 1 Column: $

The net unbilled revenue represents the following:

Base Revenue	$ (9,734,000)
Environmental Cost Recovery Accrual	10,253,000
Fuel Adjustment Clause Accrual	(14,183,000)
Demand Side Management Accrual	(3,313,927)
Levelized Fuel Factor Accrual	(1,718,000)
Off-System Sales Tracker Accrual	(114,607)
Net Unbilled	$ (18,810,534)

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue of (167,343) 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
Kentucky Utilities 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 - KY	6,062,929	581,974,084	422,070	14,365	0.0960
3	General Service - KY	-272	-21,761	1,895	-144	0.0800
4	Volunteer Fire Department - KY	121	11,399	8	15,125	0.0942
5	Low Emission Vehicle - KY	83	7,591	4	20,750	0.0915
6	Private Outdoor Lighting - KY	7,871	1,653,774	9,955	791	0.2101
7	Street Lighting - KY	16,377	3,415,765	31,105	527	0.2086
8	Traffic Energy Service - KY	2	188	2	1,000	0.0940
9	Residential Time of Day - KY	47	4,100	3	15,667	0.0872
10	Residential Service - TN	94	6,798	4	23,500	0.0723
11	Private Outdoor Lighting - TN	2	301	3	667	0.1505
12	Residential Service - VA	378,401	36,491,062	23,606	16,030	0.0964
13	General Service - VA	-18	360	214	-84	-0.0200
14	Private Outdoor Lighting - VA	3,019	764,827	4,577	660	0.2533
15	Street Lighting - VA	1	219	5	200	0.2190
16	Duplicate Customers			-45,780		
17						
18	Reclassifications and Adjustments	-50	-24,562			0.4912
19						
20						
21						
22						
23						
24						
25						
26						
27						
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32						
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34						
35						
36						
37						
38	Subtotal	6,468,607	624,284,145	447,671	14,449	0.0965
39	Unbilled	-99,957	-12,380,969			0.1239
40	Total	6,368,650	611,903,176	447,671	14,226	0.0961
41	TOTAL Billed	19,213,738	1,580,236,038	544,307	35,299	0.0822
42	Total Unbilled Rev.(See Instr. 6)	-167,343	-18,810,534	0	0	0.1124
43	TOTAL	19,046,395	1,561,425,504	544,307	34,992	0.0820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 - KY	461	43,508	397	1,161	0.0944
3	Volunteer Fire Department - KY	96	8,712	3	32,000	0.0908
4	General Service - KY	1,665,666	193,365,606	74,417	22,383	0.1161
5	All Electric School - KY	16,754	1,378,331	113	148,265	0.0823
6	Time-of-Day Secondary - KY	1,421,970	98,145,238	445	3,195,438	0.0690
7	Private Outdoor Lighting - KY	40,467	7,074,691	13,348	3,032	0.1748
8	Street Lighting - KY	6,267	1,425,009	7,153	876	0.2274
9	Special Contract - KY		45,145	1		
10	Time-of-Day Primary - KY	3,676,304	220,619,478	203	18,109,872	0.0600
11	Traffic Energy Service - KY	390	44,757	384	1,016	0.1148
12	Power Service - KY	1,886,301	161,726,564	4,238	445,092	0.0857
13	Fluctuating Load Service - KY	522,504	15,293,574	1	522,504,000	0.0293
14	Retail Transmission Service - KY	1,509,419	86,463,414	29	52,048,931	0.0573
15	Residential Service - VA	146	14,118	111	1,315	0.0967
16	General Service - VA	70,489	8,063,445	3,438	20,503	0.1144
17	Private Outdoor Lighting - VA	1,220	302,248	852	1,432	0.2477
18	Street Lighting - VA	3	637	6	500	0.2123
19	Power Service - VA	138,719	11,732,481	168	825,708	0.0846
20	Time-of-Day - VA	60,294	5,423,224	12	5,024,500	0.0899
21	School Service - VA	289	26,563	4	72,250	0.0919
22	Retail Transmission Service - VA	52,457	4,180,190	6	8,742,833	0.0797
23	Duplicate Customers			-18,491		
24						
25	Reclassifications and Adjustments		-23,089			
26						
27						
28						
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32						
33						
34						
35						
36						
37						
38	Subtotal	11,070,216	815,353,844	86,838	127,481	0.0737
39	Unbilled	-64,400	-5,902,468			0.0917
40	Total	11,005,816	809,451,376	86,838	126,740	0.0735
41	TOTAL Billed	19,213,738	1,580,236,038	544,307	35,299	0.0822
42	Total Unbilled Rev.(See Instr. 6)	-167,343	-18,810,534	0	0	0.1124
43	TOTAL	19,046,395	1,561,425,504	544,307	34,992	0.0820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
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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	Residential Service - KY	19	2,046	4	4,750	0.1077
3	General Service - KY	1,164	209,252	682	1,707	0.1798
4	Private Outdoor Lighting - KY	39,513	10,702,898	1,098	35,986	0.2709
5	Street Lighting - KY	832	340,296	124	6,710	0.4090
6	Lighting Energy - KY	40	2,700	1	40,000	0.0675
7	Traffic Energy Service - KY	692	75,928	300	2,307	0.1097
8	General Service - VA	33	4,750	5	6,600	0.1439
9	Street Lighting - VA	1,626	363,209	48	33,875	0.2234
10	Duplicate Customers			-788		
11						
12	Reclassifications and Adjustments		-56,294			
13						
14						
15						
16						
17						
18						
19						
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21						
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23						
24						
25						
26						
27						
28						
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32						
33						
34						
35						
36						
37						
38	Subtotal	43,919	11,644,785	1,474	29,796	0.2651
39	Unbilled	-419	14,798			-0.0353
40	Total	43,500	11,659,583	1,474	29,512	0.2680
41	TOTAL Billed	19,213,738	1,580,236,038	544,307	35,299	0.0822
42	Total Unbilled Rev.(See Instr. 6)	-167,343	-18,810,534	0	0	0.1124
43	TOTAL	19,046,395	1,561,425,504	544,307	34,992	0.0820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
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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 - KY	3,084	324,685	404	7,634	0.1053
3	Volunteer Fire Department - KY	997	91,809	40	24,925	0.0921
4	General Service - KY	146,951	16,885,044	5,154	28,512	0.1149
5	All Electric School - KY	132,166	10,784,620	491	269,177	0.0816
6	Power Service - KY	357,097	32,452,662	772	462,561	0.0909
7	Private Outdoor Lighting - KY	11,061	2,352,655	1,883	5,874	0.2127
8	Street Lighting - KY	980	212,532	624	1,571	0.2169
9	Time-of-Day Service Primary - KY	664,073	40,318,394	39	17,027,513	0.0607
10	Time-of-Day Service Secondary- KY	225,167	17,717,988	137	1,643,555	0.0787
11	Traffic Energy Service - KY	408	37,611	72	5,667	0.0922
12	Lighting Energy - KY	374	25,439	3	124,667	0.0680
13	Retail Transmission Service - KY	16,296	955,136	1	16,296,000	0.0586
14	Residential Service - VA	410	40,810	33	12,424	0.0995
15	General Service - VA	14,923	1,684,443	664	22,474	0.1129
16	School Service - VA	23,252	2,141,267	135	172,237	0.0921
17	Private Outdoor Lighting - VA	698	171,474	229	3,048	0.2457
18	Street Lighting - VA	7	1,513	12	583	0.2161
19	Time-of-Day - VA	4,664	407,439	2	2,332,000	0.0874
20	Power Service - VA	27,816	2,305,784	37	751,784	0.0829
21	Municipal Water Pumping - VA	572	36,668	16	35,750	0.0641
22	Duplicate Customers			-2,424		
23						
24	Reclassifications and Adjustments		5,291			
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Subtotal	1,630,996	128,953,264	8,324	195,939	0.0791
39	Unbilled	-2,567	-541,895			0.2111
40	Total	1,628,429	128,411,369	8,324	195,631	0.0789
41	TOTAL Billed	19,213,738	1,580,236,038	544,307	35,299	0.0822
42	Total Unbilled Rev.(See Instr. 6)	-167,343	-18,810,534	0	0	0.1124
43	TOTAL	19,046,395	1,561,425,504	544,307	34,992	0.0820

Name of Respondent Kentucky Utilities 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 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $(7,716,589)

Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $(776)

Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $(158)

Schedule Page: 304 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $10

Schedule Page: 304 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $(12,752)

Schedule Page: 304 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $(26,864)

Schedule Page: 304 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $(2)

Schedule Page: 304 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $(159)

Schedule Page: 304 Line No.: 16 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304 Line No.: 18 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 $(507)

Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $(102)

Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $(2,360,479)

Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $(23,344)

Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $(2,244,496)

Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $(65,514)

Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $(10,173)

Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $(5,485,479)

Schedule Page: 304.1 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $(567)

Schedule Page: 304.1 Line No.: 12 Column: c
Includes Fuel Adjustment Clause of $(2,797,964)

Schedule Page: 304.1 Line No.: 13 Column: c
Includes Fuel Adjustment Clause of $(633,671)

Schedule Page: 304.1 Line No.: 14 Column: c
Includes Fuel Adjustment Clause of $(1,975,178)

Schedule Page: 304.1 Line No.: 23 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304.1 Line No.: 25 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 $(15)

Schedule Page: 304.2 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $(1,771)

Name of Respondent Kentucky Utilities 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 $(57,876)
Schedule Page: 304.2 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $(1,219)
Schedule Page: 304.2 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $(51)
Schedule Page: 304.2 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $(972)
Schedule Page: 304.2 Line No.: 10 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.
Schedule Page: 304.2 Line No.: 12 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods.
Schedule Page: 304.3 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $(4,060)
Schedule Page: 304.3 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $(1,321)
Schedule Page: 304.3 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $(200,530)
Schedule Page: 304.3 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $(180,583)
Schedule Page: 304.3 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $(509,516)
Schedule Page: 304.3 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $(17,680)
Schedule Page: 304.3 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $(1,501)
Schedule Page: 304.3 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $(932,845)
Schedule Page: 304.3 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $(329,316)
Schedule Page: 304.3 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $(731)
Schedule Page: 304.3 Line No.: 12 Column: c
Includes Fuel Adjustment Clause of $(579)
Schedule Page: 304.3 Line No.: 13 Column: c
Includes Fuel Adjustment Clause of $(26,370)
Schedule Page: 304.3 Line No.: 22 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.
Schedule Page: 304.3 Line No.: 24 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
Kentucky Utilities 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	City of Barbourville	RQ	184	17	17	17
2	City of Bardstown	RQ	185	33	33	31
3	City of Bardwell	RQ	186	2	2	1
4	City of Benham	RQ	187	1	2	1
5	City of Berea	RQ	197	24	24	24
6	City of Corbin	RQ	188	16	16	15
7	City of Falmouth	RQ	189	3	3	3
8	City of Frankfort	RQ	190	121	121	120
9	City of Madisonville	RQ	161	49	49	45
10	City of Nicholasville	RQ	157	35	35	34
11	City of Paris	RQ	83	12	12	12
12	City of Providence	RQ	195	5	5	5
13	American Electric Power Service Corp.	OS	(3)	N/A	N/A	N/A
14	Associated Electric Coop Inc.	OS	(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
Kentucky Utilities 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.
92,880	3,049,373	478,968	2,409,190	5,937,531	1
199,833	5,487,385	972,602	5,332,050	11,792,037	2
8,952	289,918	46,418	235,140	571,476	3
3,273	209,993	17,034	93,270	320,297	4
127,716	4,235,734	658,602	3,316,355	8,210,691	5
82,728	2,742,713	426,620	2,148,297	5,317,630	6
19,699	615,860	106,293	514,026	1,236,179	7
712,264	21,365,273	3,672,929	18,406,271	43,444,473	8
300,870	8,648,722	1,560,152	7,892,051	18,100,925	9
214,176	5,766,661	1,036,228	5,540,570	12,343,459	10
62,801	2,073,424	323,792	1,634,009	4,031,225	11
30,189	953,573	156,550	789,750	1,899,873	12
11,420		435,803		435,803	13
1,360		54,097		54,097	14
1,855,381	60,344,823	9,370,163	48,310,979	118,025,965	
908,355	0	25,382,147	-1,837	25,380,310	
2,763,736	**60,344,823**	**34,752,310**	**48,309,142**	**143,406,275**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	Average Monthly CP Demand (f)
1	Benham Power Board	OS	(6)	N/A	N/A	N/A
2	Bluegrass Generation Company, LLC	OS	(8)	N/A	N/A	N/A
3	Brookfield Energy Marketing LP	OS	(3)	N/A	N/A	N/A
4	Cargill Power Markets, LLC	OS	(3)	N/A	N/A	N/A
5	ETC Endure Energy, LLC	OS	(3)	N/A	N/A	N/A
6	Exelon Generation Company, LLC	OS	(3)	N/A	N/A	N/A
7	Illinois Municipal Electric Agency	OS	(5)	N/A	N/A	N/A
8	Illinois Municipal Electric Agency	OS	(3)	N/A	N/A	N/A
9	Illinois Municipal Electric Agency	AD	(3)	N/A	N/A	N/A
10	Indiana Municipal Power Agency	OS	(7)	N/A	N/A	N/A
11	Indiana Municipal Power Agency	OS	(3)	N/A	N/A	N/A
12	Indiana Municipal Power Agency	AD	(3)	N/A	N/A	N/A
13	Kentucky Municipal Power Agency	OS	(6)	N/A	N/A	N/A
14	Louisville Gas and Electric Company	SF	(1)	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
Kentucky Utilities 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		239		239	1
121		4,061		4,061	2
6		366		366	3
17,977		746,746		746,746	4
1,914		80,176		80,176	5
2,610		117,239		117,239	6
152		4,433		4,433	7
1,637		83,717		83,717	8
			-700	-700	9
1,715		54,129		54,129	10
1,611		123,036		123,036	11
			-1,200	-1,200	12
683		22,786		22,786	13
775,699		19,648,847		19,648,847	14
1,855,381	60,344,823	9,370,163	48,310,979	118,025,965	
908,355	0	25,382,147	-1,837	25,380,310	
2,763,736	**60,344,823**	**34,752,310**	**48,309,142**	**143,406,275**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	Average Monthly CP Demand (f)
1	Midcontinent Independent System Oper	OS	(3)	N/A	N/A	N/A
2	Midcontinent Independent System Oper	AD	(3)	N/A	N/A	N/A
3	Owensboro Municipal Utilities	OS	(2)	N/A	N/A	N/A
4	Owensboro Municipal Utilities	OS	(6)	N/A	N/A	N/A
5	PJM Settlements, Inc.	OS	(3)	N/A	N/A	N/A
6	Tenaska Power Services Company	OS	(3)	N/A	N/A	N/A
7	Tennessee Valley Authority	OS	(3)	N/A	N/A	N/A
8	The Energy Authority, Inc.	OS	(3)	N/A	N/A	N/A
9	Westar Energy, Inc.	OS	(3)	N/A	N/A	N/A
10	City of Barbourville	RQ	184	N/A	N/A	N/A
11	City of Bardstown	RQ	185	N/A	N/A	N/A
12	City of Bardwell	RQ	186	N/A	N/A	N/A
13	City of Benham	RQ	187	N/A	N/A	N/A
14	City of Berea	RQ	197	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
Kentucky Utilities 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.
15,077		632,881		632,881	1
			63	63	2
1,083		38,785		38,785	3
2,256		80,096		80,096	4
48,954		2,258,074		2,258,074	5
1,443		61,251		61,251	6
12,913		520,415		520,415	7
1,439		58,354		58,354	8
8,279		356,616		356,616	9
	262,429	-4,264		258,165	10
	516,611	-9,434		507,177	11
	26,764	-422		26,342	12
	18,523	-258		18,265	13
	344,909	-5,834		339,075	14
1,855,381	60,344,823	9,370,163	48,310,979	118,025,965	
908,355	0	25,382,147	-1,837	25,380,310	
2,763,736	**60,344,823**	**34,752,310**	**48,309,142**	**143,406,275**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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:
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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.
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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.
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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	City of Corbin	RQ	188	N/A	N/A	N/A
2	City of Falmouth	RQ	189	N/A	N/A	N/A
3	City of Frankfort	RQ	190	N/A	N/A	N/A
4	City of Madisonville	RQ	161	N/A	N/A	N/A
5	City of Nicholasville	RQ	157	N/A	N/A	N/A
6	City of Paris	RQ	83	N/A	N/A	N/A
7	City of Providence	RQ	195	N/A	N/A	N/A
8						
9						
10						
11						
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
Kentucky Utilities 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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
	241,051	-3,832		237,219	1
	57,332	-913		56,419	2
	1,878,144	-32,656		1,845,488	3
	815,094	-14,445		800,649	4
	517,335	-9,743		507,592	5
	138,712	-2,780		135,932	6
	89,290	-1,444		87,846	7
					8
					9
					10
					11
					12
					13
					14
1,855,381	60,344,823	9,370,163	48,310,979	118,025,965	
908,355	0	25,382,147	-1,837	25,380,310	
2,763,736	**60,344,823**	**34,752,310**	**48,309,142**	**143,406,275**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: c
City of Barbourville Rate Schedule FERC No. 184 effective June 2014

Schedule Page: 310 Line No.: 1 Column: j
Amounts include RQ's related to $6,679 for direct assignment charge and $2,402,511 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 2 Column: c
City of Bardstown Rate Schedule FERC No. 185 effective April 2014

Schedule Page: 310 Line No.: 2 Column: j
Amounts include RQ's related to $185,404 for direct assignment charge and $5,146,646 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 3 Column: c
City of Bardwell Rate Schedule FERC No. 186 effective June 2014

Schedule Page: 310 Line No.: 3 Column: j
Amounts include RQ's related to $4,135 for direct assignment charge and $231,005 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 4 Column: c
City of Benham Rate Schedule FERC No. 187 effective June 2014

Schedule Page: 310 Line No.: 4 Column: j
Amounts include RQ's related to $1,721 for direct assignment charge and $91,549 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 5 Column: c
City of Berea Rate Schedule FERC No. 197 effective June 2014

Schedule Page: 310 Line No.: 5 Column: j
Amounts include RQ's related to $8,690 for direct assignment charge and $3,307,665 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 6 Column: c
City of Corbin Rate Schedule FERC No. 188 effective June 2014

Schedule Page: 310 Line No.: 6 Column: j
Amounts include RQ's related to $10,762 for direct assignment charge and $2,137,535 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 7 Column: c
City of Falmouth Rate Schedule FERC No. 189 effective June 2014

Schedule Page: 310 Line No.: 7 Column: j
Amounts include RQ's related to $5,816 for direct assignment charge and $508,210 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 8 Column: c
City of Frankfort Rate Schedule FERC No. 190 effective June 2014

Schedule Page: 310 Line No.: 8 Column: j
Amounts include RQ's related to $30,680 for direct assignment charge and $18,375,591 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 9 Column: c
City of Madisonville Rate Schedule FERC No. 161 effective June 2014

Schedule Page: 310 Line No.: 9 Column: j
Amounts include RQ's related to $145,802 for direct assignment charge and $7,746,249 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 10 Column: c
City of Nicholasville Rate Schedule FERC No. 157 effective April 2014

Schedule Page: 310 Line No.: 10 Column: j
Amounts include RQ's related to $9,041 for direct assignment charge and $5,531,529 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 11 Column: c
City of Paris Rate Schedule FERC No. 83 effective June 2014

Schedule Page: 310 Line No.: 11 Column: j
Amounts include RQ's related to $6,083 for direct assignment charge and $1,627,926 for wholesale municipal fuel adjustment clause.

Name of Respondent Kentucky Utilities 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.: 12 Column: c
City of Providence Rate Schedule FERC No. 195 effective June 2014

Schedule Page: 310 Line No.: 12 Column: j
Amounts include RQ's related to $10,966 for direct assignment charge and $778,784 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 13 Column: b
Market Based Sale

Schedule Page: 310 Line No.: 13 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 14 Column: b
Market Based Sale

Schedule Page: 310 Line No.: 14 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

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: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 2 Column: c
(8) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255

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
Market Based Sale

Schedule Page: 310.1 Line No.: 4 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 5 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 5 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 6 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 6 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 7 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 7 Column: c
(5) LGE CBR Tariff First Revised Service Agreement No. 3

Schedule Page: 310.1 Line No.: 8 Column: b
Energy Imbalance

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
December 2014 correction made in 2015.

Schedule Page: 310.1 Line No.: 9 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 9 Column: j
December 2014 correction made in 2015.

Schedule Page: 310.1 Line No.: 10 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 10 Column: c
(7) LGE CBR Tariff Service Agreement No. 4

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 310.1 Line No.: 11 Column: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 11 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 12 Column: b
December 2014 correction made in 2015.

Schedule Page: 310.1 Line No.: 12 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 12 Column: j
December 2014 correction made in 2015.

Schedule Page: 310.1 Line No.: 13 Column: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 13 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 310.1 Line No.: 14 Column: a
KU and LG&E are owned by PPL.

Schedule Page: 310.1 Line No.: 14 Column: c
(1) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000

Schedule Page: 310.2 Line No.: 1 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 1 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 2 Column: b
December 2014 correction made in 2015.

Schedule Page: 310.2 Line No.: 2 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 2 Column: j
December 2014 correction made in 2015.

Schedule Page: 310.2 Line No.: 3 Column: b
Cost based sale

Schedule Page: 310.2 Line No.: 3 Column: c
(2) LGE CBR Tariff and pro forma Service Agreement

Schedule Page: 310.2 Line No.: 4 Column: b
Energy Imbalance

Schedule Page: 310.2 Line No.: 4 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 310.2 Line No.: 5 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 5 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 6 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 6 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 7 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 7 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 8 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 8 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 9 Column: b
Market Based Sale

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 310.2 Line No.: 9 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.2 Line No.: 10 Column: b
2014 correction made in 2015.

Schedule Page: 310.2 Line No.: 11 Column: b
2014 correction made in 2015.

Schedule Page: 310.2 Line No.: 12 Column: b
2014 correction made in 2015.

Schedule Page: 310.2 Line No.: 13 Column: b
2014 correction made in 2015.

Schedule Page: 310.2 Line No.: 14 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 1 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 2 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 3 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 4 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 5 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 6 Column: b
2014 correction made in 2015.

Schedule Page: 310.3 Line No.: 7 Column: b
2014 correction made in 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	10,412,572	9,696,931
5	(501) Fuel	434,997,400	489,411,202
6	(502) Steam Expenses	22,908,345	20,491,481
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	8,264,603	8,001,787
10	(506) Miscellaneous Steam Power Expenses	30,618,338	27,820,677
11	(507) Rents	12,000	9,967
12	(509) Allowances	18,228	159,712
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	507,231,486	555,591,757
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,805,551	8,169,573
16	(511) Maintenance of Structures	7,740,621	7,051,419
17	(512) Maintenance of Boiler Plant	44,608,302	50,890,207
18	(513) Maintenance of Electric Plant	16,581,871	12,110,369
19	(514) Maintenance of Miscellaneous Steam Plant	3,008,084	2,061,766
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	80,744,429	80,283,334
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	587,975,915	635,875,091
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		8,614
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	60,343	99,863
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	60,343	108,477
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	130,012	130,651
54	(542) Maintenance of Structures	810,430	185,530
55	(543) Maintenance of Reservoirs, Dams, and Waterways	6,398	35,892
56	(544) Maintenance of Electric Plant	44,739	146,631
57	(545) Maintenance of Miscellaneous Hydraulic Plant	5,405	6,296
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	996,984	505,000
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,057,327	613,477

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Kentucky Utilities 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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	691,003	231,037
63	(547) Fuel	105,905,279	78,666,577
64	(548) Generation Expenses	393,571	380,227
65	(549) Miscellaneous Other Power Generation Expenses	2,695,833	165,947
66	(550) Rents	25,398	19,263
67	TOTAL Operation (Enter Total of lines 62 thru 66)	109,711,084	79,463,051
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	96,271	60,239
70	(552) Maintenance of Structures	632,058	193,806
71	(553) Maintenance of Generating and Electric Plant	3,075,489	2,281,389
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,395,518	274,755
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	6,199,336	2,810,189
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	115,910,420	82,273,240
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	52,003,009	108,042,627
77	(556) System Control and Load Dispatching	1,950,246	1,663,905
78	(557) Other Expenses	85,342	75,176
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	54,038,597	109,781,708
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	758,982,259	828,543,516
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,772,984	1,732,676
84			
85	(561.1) Load Dispatch-Reliability	509,431	1,981,505
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,989,765	256,730
87	(561.3) Load Dispatch-Transmission Service and Scheduling	708,930	149,238
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	918,887	881,658
90	(561.6) Transmission Service Studies	9,085	6,923
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,254,789	1,186,115
94	(563) Overhead Lines Expenses	711,836	872,862
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,381,568	3,162,039
97	(566) Miscellaneous Transmission Expenses	11,029,494	10,514,352
98	(567) Rents	152,237	98,377
99	TOTAL Operation (Enter Total of lines 83 thru 98)	22,439,006	20,842,475
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	368	
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	2,631,984	2,845,292
108	(571) Maintenance of Overhead Lines	6,125,495	6,249,590
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	586,129	331,541
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,343,976	9,426,423
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	31,782,982	30,268,898

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Kentucky Utilities 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	-308,163	-176,057
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	-308,163	-176,057
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)	-308,163	-176,057
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,384,841	1,609,144
135	(581) Load Dispatching	527,155	835,866
136	(582) Station Expenses	1,966,108	1,962,059
137	(583) Overhead Line Expenses	5,497,286	7,378,286
138	(584) Underground Line Expenses	880	
139	(585) Street Lighting and Signal System Expenses	1,239	
140	(586) Meter Expenses	7,817,019	7,824,415
141	(587) Customer Installations Expenses	-52,906	-40,961
142	(588) Miscellaneous Expenses	4,774,845	4,466,548
143	(589) Rents	9,167	8,499
144	TOTAL Operation (Enter Total of lines 134 thru 143)	21,925,634	24,043,856
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	150,869	116,607
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	979,896	1,153,139
149	(593) Maintenance of Overhead Lines	31,913,312	32,899,959
150	(594) Maintenance of Underground Lines	436,207	584,424
151	(595) Maintenance of Line Transformers	92,466	112,250
152	(596) Maintenance of Street Lighting and Signal Systems	436	331
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	125,239	571,699
155	TOTAL Maintenance (Total of lines 146 thru 154)	33,698,425	35,438,409
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	55,624,059	59,482,265
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	3,900,537	3,463,059
160	(902) Meter Reading Expenses	5,007,040	5,019,304
161	(903) Customer Records and Collection Expenses	17,412,429	16,703,361
162	(904) Uncollectible Accounts	4,797,655	8,005,373
163	(905) Miscellaneous Customer Accounts Expenses	3,389	132,257
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	31,121,050	33,323,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	357,461	391,320
168	(908) Customer Assistance Expenses	16,774,813	16,927,353
169	(909) Informational and Instructional Expenses	735,261	409,361
170	(910) Miscellaneous Customer Service and Informational Expenses	664,908	636,471
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	18,532,443	18,364,505
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	307,100	94,091
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	307,100	94,091
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	36,079,107	33,903,395
182	(921) Office Supplies and Expenses	7,461,032	7,449,885
183	(Less) (922) Administrative Expenses Transferred-Credit	4,891,341	4,764,234
184	(923) Outside Services Employed	19,603,597	17,999,000
185	(924) Property Insurance	5,708,950	5,190,649
186	(925) Injuries and Damages	4,743,877	3,436,518
187	(926) Employee Pensions and Benefits	41,616,801	28,105,099
188	(927) Franchise Requirements	3,836	3,955
189	(928) Regulatory Commission Expenses	1,665,507	1,698,218
190	(929) (Less) Duplicate Charges-Cr.	3,836	3,955
191	(930.1) General Advertising Expenses	118,945	947,079
192	(930.2) Miscellaneous General Expenses	4,238,094	4,161,143
193	(931) Rents	2,046,222	2,510,086
194	TOTAL Operation (Enter Total of lines 181 thru 193)	118,390,791	100,636,838
195	Maintenance		
196	(935) Maintenance of General Plant	2,457,869	2,456,984
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	120,848,660	103,093,822
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,016,890,390	1,072,994,394

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 121 Column: b

The credit 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 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 the cost of meter maintenance. The cost is recorded in several accounts.

Schedule Page: 320 Line No.: 141 Column: c

The credit is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	OS	(7)	N/A	N/A	N/A
3	City of Paris	OS	(5)	N/A	N/A	N/A
4	City of Paris	AD	(5)	N/A	N/A	N/A
5	East Kentucky Power Cooperative, Inc.	OS	(11)	N/A	N/A	N/A
6	East Kentucky Power Cooperative, Inc.	OS	(3)	N/A	N/A	N/A
7	Fayette County Board of Education	OS	(9)	N/A	N/A	N/A
8	Illinois Municipal Electric Agency	EX	(8)	N/A	N/A	N/A
9	Illinois Municipal Electric Agency	AD	(8)	N/A	N/A	N/A
10	Indiana Municipal Power Agency	EX	(8)	N/A	N/A	N/A
11	Indiana Municipal Power Agency	AD	(8)	N/A	N/A	N/A
12	Kentucky Municipal Power Agency	OS	(3)	N/A	N/A	N/A
13	Kentucky National Guard	OS	(9)	N/A	N/A	N/A
14	Louisville Gas and Electric 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
Kentucky Utilities 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)	
14				418		418	1
173				5,274		5,274	2
6				140		140	3
-24					-733	-733	4
49				1,715		1,715	5
6				186		186	6
92				3,241		3,241	7
1,056				4,947		4,947	8
					-1,116	-1,116	9
956				7,071		7,071	10
					-820	-820	11
1,706				59,481		59,481	12
17				1,155		1,155	13
1,481,943				36,859,944		36,859,944	14
1,732,372	480,568		7,947,001	43,957,487	98,521	52,003,009	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	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	Rockcastle Hospital Annex	OS	(9)	N/A	N/A	N/A
6	Tennessee Valley Authority	OS	(10)	N/A	N/A	N/A
7	Tennessee Valley Authority	OS	(4)	N/A	N/A	N/A
8	Inadvertent Interchange			N/A	N/A	N/A
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	
234,867			7,947,001	6,680,643		14,627,644	1
					101,190	101,190	2
1,038				27,933		27,933	3
1,805				63,147		63,147	4
68				2,424		2,424	5
7,938				163,752		163,752	6
662				76,016		76,016	7
	480,568						8
							9
							10
							11
							12
							13
							14
1,732,372	480,568		7,947,001	43,957,487	98,521	52,003,009	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: b
Energy Imbalance
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
Energy Imbalance
Schedule Page: 326 Line No.: 2 Column: c
(7) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255
Schedule Page: 326 Line No.: 3 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 3 Column: c
(5) FERC-approved tariff and or rate schedule on file with the Commission
Schedule Page: 326 Line No.: 4 Column: b
December 2014 correction made in 2015.
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.: 4 Column: l
December 2014 correction made in 2015.
Schedule Page: 326 Line No.: 5 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 5 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.: 6 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 6 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 326 Line No.: 7 Column: b
Small Capacity Cogeneration and Small Power Production Qualifying Facility
Schedule Page: 326 Line No.: 7 Column: c
(9) KPSC Standard Rate Rider
Schedule Page: 326 Line No.: 8 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 8 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.: 9 Column: b
December 2014 correction made in 2015.
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.: 9 Column: l
December 2014 correction made in 2015.
Schedule Page: 326 Line No.: 10 Column: b
Energy Imbalance
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.: 11 Column: b
December 2014 correction made in 2015.
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.: 11 Column: l

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

December 2014 correction made in 2015.

Schedule Page: 326 Line No.: 12 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 12 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326 Line No.: 13 Column: b
Small Capacity Cogeneration and Small Power Production Qualifying Facility

Schedule Page: 326 Line No.: 13 Column: c
(9) KPSC Standard Rate Rider

Schedule Page: 326 Line No.: 14 Column: a
KU and LG&E 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 2.5% 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 2.5% 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 made 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
Small Capacity Cogeneration and Small Power Production Qualifying Facility

Schedule Page: 326.1 Line No.: 5 Column: c
(9) KPSC Standard Rate Rider

Schedule Page: 326.1 Line No.: 6 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 6 Column: c
(10) FERC Electric Rate Schedule No. 28 Interchange Agreement dated July 1, 1977

Schedule Page: 326.1 Line No.: 7 Column: b

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

Emergency Power

Schedule Page: 326.1 Line No.: 7 Column: c

(4) FERC-approved tariff and/or rate schedule as on file with the Commission. TEE Contingency Reserve Sharing Agreement dated November 20, 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Midwest ISO	Midwest ISO	Midwest ISO	AD
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
4	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF
5	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
6	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
7	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	FNO
8	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	AD
9	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	AD
10	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO
11	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
12	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP
13	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
14	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
15	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF
16	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
17	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	FNO
18	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
19	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
20	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
21	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF
22	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
23	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
24	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO
25	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	AD
26	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	AD
27	City of Benham	Midwest ISO	City of Benham	FNO
28	City of Benham	Midwest ISO	City of Benham	OS
29	City of Benham	Midwest ISO	City of Benham	AD
30	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO
31	Hoosier Energy	Midwest ISO	Hoosier Energy	AD
32	Hoosier Energy	Midwest ISO	Hoosier Energy	AD
33	KU/LG&E	Various	Various	NF
34	KU/LG&E	Various	Various	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
N/A	Midwest ISO	N/A				1
LGE/KU Joint	East Kentucky Power	East Kentucky Power	293	1,868,125	1,868,125	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	East Kentucky Power	East Kentucky Power				6
SA 13	Various	LGEE.KMPA	78	479,661	479,661	7
SA 13	Various	LGEE.KMPA				8
SA 13	Various	LGEE.KMPA				9
SA 15	Owensboro Municipal	Various	88	4,072	4,072	10
SA 15	Owensboro Municipal	Various				11
LGE/KU Joint	Owensboro Municipal	Various	178	1,023,431	1,023,431	12
LGE/KU Joint	Owensboro Municipal	Various				13
LGE/KU Joint	Owensboro Municipal	Various				14
LGE/KU Joint	Owensboro Municipal	Various				15
LGE/KU Joint	Owensboro Municipal	Various				16
LGE/KU Joint	TVA	TVA	48	251,630	251,630	17
LGE/KU Joint	TVA	TVA				18
LGE/KU Joint	TVA	TVA				19
LGE/KU Joint	TVA	TVA				20
LGE/KU Joint	TVA	TVA				21
LGE/KU Joint	TVA	TVA				22
LGE/KU Joint	TVA	TVA				23
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric	7	51,244	51,244	24
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric				25
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric				26
LGE/KU Joint	Midwest ISO	City of Benham	1	2,155	2,155	27
LGE/KU Joint	Midwest ISO	City of Benham				28
LGE/KU Joint	Midwest ISO	City of Benham				29
LGE/KU Joint	Midwest ISO	Hoosier Energy	3	23,803	23,803	30
LGE/KU Joint	Midwest ISO	Hoosier Energy				31
LGE/KU Joint	Midwest ISO	Hoosier Energy				32
LGE/KU Joint	Various	Various				33
LGE/KU Joint	Various	Various				34
			3,326	**3,710,923**	**3,710,923**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	KU/LG&E	Various	Various	SFP
2	KU/LG&E	Various	Various	LFP
3	The Energy Authority	Various	Various	SFP
4	The Energy Authority	Various	Various	NF
5	The Energy Authority	Various	Various	AD
6	The Energy Authority	Various	Various	AD
7	Dynegy Energy	Various	Various	SFP
8	Dynegy Energy	Various	Various	AD
9	EDF Trading	Various	Various	NF
10	EDF Trading	Various	Various	AD
11	Cargill Power Markets, LLC	Various	Various	AD
12	Constellation Energy Commodities Group	PJM	TVA	AD
13	City of Barbourville	Various	City of Barbourville	FNO
14	City of Barbourville	Various	City of Barbourville	AD
15	City of Bardstown	Various	City of Bardstown	FNO
16	City of Bardstown	Various	City of Bardstown	AD
17	City of Bardwell	Various	City of Bardwell	FNO
18	City of Bardwell	Various	City of Bardwell	AD
19	City of Benham	Various	City of Benham	FNO
20	City of Benham	Various	City of Benham	AD
21	City of Berea	Various	City of Berea	FNO
22	City of Berea	Various	City of Berea	AD
23	City of Corbin	Various	City of Corbin	FNO
24	City of Corbin	Various	City of Corbin	AD
25	City of Falmouth	Various	City of Falmouth	FNO
26	City of Falmouth	Various	City of Falmouth	FNO
27	City of Falmouth	Various	City of Falmouth	AD
28	City of Frankfort	Various	City of Frankfort	FNO
29	City of Frankfort	Various	City of Frankfort	AD
30	City of Madisonville	Various	City of Madisonville	FNO
31	City of Madisonville	Various	City of Madisonville	AD
32	City of Nicholasville	Various	City of Nicholasville	FNO
33	City of Nicholasville	Various	City of Nicholasville	AD
34	City of Paris	Various	City of Paris	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
LGE/KU Joint	Various	Various	46			1
LGE/KU Joint	Various	Various	17			2
LGE/KU Joint	Various	Various	3	4,709	4,709	3
LGE/KU Joint	Various	Various		193	193	4
LGE/KU Joint	Various	Various				5
LGE/KU Joint	Various	Various				6
LGE/KU Joint	Various	Various				7
LGE/KU Joint	Various	Various				8
LGE/KU Joint	Various	Various		1,900	1,900	9
LGE/KU Joint	Various	Various				10
LGE/KU Joint	Various	Various				11
LGE/KU Joint	PJM	TVA				12
184	Various	City of Barbourville	141			13
184	Various	City of Barbourville				14
185	Various	City of Bardstown	269			15
185	Various	City of Bardstown				16
186	Various	City of Bardwell	13			17
186	Various	City of Bardwell				18
187	Various	City of Benham	6			19
187	Various	City of Benham				20
197	Various	City of Berea	197			21
197	Various	City of Berea				22
188	Various	City of Corbin	125			23
188	Various	City of Corbin				24
189	Various	City of Falmouth	28			25
189	Various	City of Falmouth				26
189	Various	City of Falmouth				27
190	Various	City of Frankfort	985			28
190	Various	City of Frankfort				29
161	Various	City of Madisonville	359			30
161	Various	City of Madisonville	26			31
157	Various	City of Nicholasvill	278			32
157	Various	City of Nicholasvill	96			33
83	Various	City of Paris	41			34
			3,326	**3,710,923**	**3,710,923**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 Paris	Various	City of Paris	AD
2	City of Providence	Various	City of Providence	FNO
3	City of Providence	Various	City of Providence	AD
4				
5				
6				
7				
8				
9				
10				
11				
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13				
14				
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31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
83	Various	City of Paris				1
195	Various	City of Providence				2
195	Various	City of Providence				3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			3,326	**3,710,923**	**3,710,923**	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	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.
145,043			145,043	1
4,262,659		410,223	4,672,882	2
-26,626			-26,626	3
	5,727	407	6,134	4
-5,339	-214		-5,553	5
-13,767			-13,767	6
1,404,797		360,787	1,765,584	7
30,046			30,046	8
-3,762			-3,762	9
1,243,270		320,313	1,563,583	10
39,693			39,693	11
3,139,500		319,923	3,459,423	12
44,170			44,170	13
-8,640			-8,640	14
	353,157	25,974	379,131	15
	4,852		4,852	16
822,206		77,781	899,987	17
-9,067			-9,067	18
-20,008			-20,008	19
21,490			21,490	20
	15	1	16	21
	6		6	22
	-786		-786	23
111,425		11,636	123,061	24
824			824	25
2,254	-3,594		-1,340	26
7,664		2,036	9,700	27
		1,647	1,647	28
-27			-27	29
54,394		5,279	59,673	30
-134			-134	31
-22			-22	32
	693,679	52,893	746,572	33
-2,598			-2,598	34
15,716,005	**1,100,120**	**1,894,652**	**18,710,777**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
295,164		26,091	321,255	1
301,880		30,762	332,642	2
7,952		642	8,594	3
	661	52	713	4
-9			-9	5
1			1	6
		-379	-379	7
	38,522		38,522	8
	6,961	548	7,509	9
	72		72	10
	-185		-185	11
	1,247		1,247	12
209,231		9,431	218,662	13
1,050			1,050	14
401,780		17,988	419,768	15
2,376			2,376	16
18,675		829	19,504	17
-247			-247	18
8,927		455	9,382	19
96			96	20
290,727		13,200	303,927	21
1,143			1,143	22
185,614		8,329	193,943	23
1,125			1,125	24
40,979		1,829	42,808	25
		74,813	74,813	26
174			174	27
1,465,616		65,921	1,531,537	28
7,504			7,504	29
574,142		27,443	601,585	30
41,845			41,845	31
413,099		18,637	431,736	32
2,543			2,543	33
141,833		6,424	148,257	34
15,716,005	**1,100,120**	**1,894,652**	**18,710,777**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
1,281			1,281	1
61,415		2,737	64,152	2
644			644	3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
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				28
				29
				30
				31
				32
				33
				34
15,716,005	**1,100,120**	**1,894,652**	**18,710,777**	

Name of Respondent Kentucky Utilities 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: 328 Line No.: 1 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 2 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 3 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 4 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 5 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 5 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 6 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 7 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.: 8 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 9 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 10 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.: 11 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 12 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 13 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 14 Column: k
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 15 Column: m
The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 16 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 17 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 18 Column: k
The total consists of a true-up of prior periods.

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 Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 22 Column: l
The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 23 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328 Line No.: 24 Column: m
The total consists of Big Rivers Electric Corporation Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 25 Column: k
The total consists of a true-up of prior periods.

Name of Respondent Kentucky Utilities 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: 328 Line No.: 26 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328 Line No.: 26 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328 Line No.: 27 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.: 28 Column: m
The total consists of City of Benham Direct Facility Assignment Charges.
Schedule Page: 328 Line No.: 29 Column: k
The total consists of a true-up of prior periods.
Schedule Page: 328 Line No.: 30 Column: m
The total consists of Hoosier Energy Schedule 1 and Schedule 2 charges.
Schedule Page: 328 Line No.: 31 Column: k
The total consists of a true-up of prior periods.
Schedule Page: 328 Line No.: 32 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328 Line No.: 33 Column: a
KU and LG&E are owned by PPL.
Schedule Page: 328 Line No.: 33 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 34 Column: a
KU and LG&E are owned by PPL.
Schedule Page: 328 Line No.: 34 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 1 Column: a
KU and LG&E are owned by PPL.
Schedule Page: 328.1 Line No.: 1 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.
Schedule Page: 328.1 Line No.: 2 Column: a
KU and LG&E are owned by PPL.
Schedule Page: 328.1 Line No.: 2 Column: d
Long-term Firm purchases by KU and LG&E take place under the Open Access Transmission Tariff 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: 328.1 Line No.: 2 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328.1 Line No.: 3 Column: m
The total consists of The Energy Authority Schedule 1 and Schedule 2 charges.
Schedule Page: 328.1 Line No.: 4 Column: m
The total consists of The Energy Authority Schedule 1 and Schedule 2 charges.
Schedule Page: 328.1 Line No.: 5 Column: k
The total consists of a true-up of prior periods.
Schedule Page: 328.1 Line No.: 6 Column: k
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 Dynegy Energy Schedule 2 charges.

Schedule Page: 328.1 Line No.: 8 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 9 Column: m
The total consists of EDF Trading Schedule 1 and Schedule 2 charges.

Name of Respondent Kentucky Utilities 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: 328.1 Line No.: 10 Column: l
The total consists of a true-up of prior periods.
Schedule Page: 328.1 Line No.: 11 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 12 Column: l
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 13 Column: m
The total consists of City of Barbourville Schedule 1 charges.
Schedule Page: 328.1 Line No.: 14 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 15 Column: m
The total consists of City of Bardstown Schedule 1 charges.
Schedule Page: 328.1 Line No.: 16 Column: k
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 Bardwell 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 Benham 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 Berea 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 Corbin 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 Falmouth Schedule 1 charges.
Schedule Page: 328.1 Line No.: 26 Column: m
The total consists of City of Falmouth Schedule 1 and Schedule 2 charges.
Schedule Page: 328.1 Line No.: 27 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 28 Column: m
The total consists of City of Frankfort Schedule 1 charges.
Schedule Page: 328.1 Line No.: 29 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 30 Column: m
The total consists of City of Madisonville Schedule 1 charges.
Schedule Page: 328.1 Line No.: 31 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 32 Column: m
The total consists of City of Nicholasville Schedule 1 charges.
Schedule Page: 328.1 Line No.: 33 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.1 Line No.: 34 Column: m
The total consists of City of Paris Schedule 1 charges.
Schedule Page: 328.2 Line No.: 1 Column: k
The total consists of a true-up of prior periods related to OATT rate adjustments.
Schedule Page: 328.2 Line No.: 2 Column: m
The total consists of City of Providence Schedule 1 charges.
Schedule Page: 328.2 Line No.: 3 Column: k

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

The total consists of a true-up of prior periods related to OATT rate adjustments.

Schedule Page: 328.2 Line No.: 3 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	$ 18,710,777
Elimination of intracompany transmission revenues	(834,586)
Schedule Page: 300, Line No.: 22, Column: b	$ 17,876,191

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	EKPC	LFP					218,666	218,666
2	KU/LG&E	LFP	164,386	164,386	401,258		40,774	442,032
3	KU/LG&E	SFP	118,528	118,528	287,278		23,199	310,477
4	KU/LG&E	NF	96,560	96,560		431,764	31,095	462,859
5	PJM Interconnect	LFP			2,665,156			2,665,156
6	PJM Interconnect	SFP	34,378	34,378	103,885			103,885
7	PJM Interconnect	NF	2,635	2,635		1,766	10,629	12,395
8	PJM Interconnect	AD				-480	1,165	685
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		416,487	416,487	3,457,577	433,050	325,528	4,216,155

Name of Respondent Kentucky Utilities 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: 332 Line No.: 1 Column: b
The LFP transmission service agreement between East Kentucky Power Cooperative (EKPC) and KU and LG&E has a termination date of 9/30/2016.

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
KU and LG&E are owned by PPL.

Schedule Page: 332 Line No.: 2 Column: b
Long-Term Firm purchases by KU and LG&E 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.: 2 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 3 Column: a
KU and LG&E 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.: 4 Column: a
KU and LG&E are owned by PPL.

Schedule Page: 332 Line No.: 4 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 7 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 8 Column: f
The total consists of a true-up of prior periods.

Schedule Page: 332 Line No.: 8 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.: 8 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	$ 4,216,155
Elimination of intracompany transmission expenses	(834,586)
Rounding	(1)
Schedule Page: 321, Line No.: 96, Column: b	$ 3,381,568

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	977,853
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,705,097
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	118,360
8	Vision Critical Communications US Inc	27,240
9	Insight Services	9,024
10	Training and Subscription Expenses:	
11	IEEE Customer Operations	10,582
12	J.Y. Legner Associates, Inc	5,423
13	Water Use Fees	65,269
14	Miscellaneous	319,246
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46	TOTAL	4,238,094

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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			10,864,312		10,864,312
2	Steam Production Plant	111,958,479				111,958,479
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	1,125,889				1,125,889
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	27,816,799				27,816,799
7	Transmission Plant	14,413,824				14,413,824
8	Distribution Plant	42,422,663				42,422,663
9	Regional Transmission and Market Operation					
10	General Plant	11,533,606				11,533,606
11	Common Plant-Electric					
12	TOTAL	209,271,260		10,864,312		220,135,572

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2015	AMORTIZATION	
130200	19%	$ 55,919	$ 10,502	
130300	15%	51,209,432	6,756,190	
130310	10%	41,045,495	4,097,620	

			$ 10,864,312	Column (d)

Name of Respondent Kentucky Utilities 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

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	46,895	60.00		2.62	60-S1.5	38.20
15							
16	342 Fuel Holders Prdcr						
17	0172 Cane Run Unit 7	111,536	55.00	-5.00	2.73	55-R3	38.42
18							
19	343 Prime Movers						
20	0172 Cane Run Unit 7	89,873	55.00	-5.00	2.79	55-R2.5	37.68
21							
22	344 Generators						
23	0172 Cane Run Unit 7	113,390	50.00	-10.00	3.11	50-R1.5	35.35
24							
25	345 Accessry Elec Eqpm						
26	0172 Cane Run Unit 7	26,286	50.00	-5.00	2.97	50-S0.5	35.33
27							
28	346 Misc Plant Eqpmt						
29	0172 Cane Run Unit 7	21	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
Kentucky Utilities 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	406,748		406,748	
3	2014 FERC Municipal Rate Case		175,092	175,092	
4					
5	State Corporation Commission of Virginia				
6	2015 Rate Case		165,838	165,838	
7					
8	KPSC				
9	2014 Rate Case (Jul-15 to Jun-18)		318,831	318,831	1,357,905
10					
11	2012 Rate Case (Jan-13 to Dec-15)		551,491	551,491	551,491
12					
13	2011 Gen Mgmt Audit (Jan-13 to Dec-15)		47,507	47,507	47,507
14					
15					
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46	TOTAL	406,748	1,258,759	1,665,507	1,956,903

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	406,748					2
Electric	928	175,092					3
							4
							5
Electric	928	165,838					6
							7
							8
Electric	928	318,831	554,664	928	318,831	1,593,738	9
							10
Electric	928	551,491		928	551,491		11
							12
Electric	928	47,507		928	45,507		13
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		1,665,507	554,664		915,829	1,593,738	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	HDR ENGINEERING Inc (1)	Tailored Collaboration for Energy Storage Demonstration
8	HDR ENGINEERING Inc (1)	Tailored Collaboration for Construction Drawings and Procurement Specifics
9	HDR ENGINEERING Inc (1)	Tailored Collaboration for Construction Drawings and Procurement Specifics
10	University of Kentucky Research Foundation (4)	Amortization of Carbon Capturing Research Regulatory Asset
11	University of Texas at Austin (4)	Tailored Collaboration
12	Georgia Tech Research Corporation (1)	NEETRAC Membership Renewal
13	Ronald Doades and Company (1)	Annual Participation in Research & Technology Management Forum
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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 Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
	2,421,324	930	2,421,324		1
	209,852	107	209,852		2
	70,684	183	70,684		3
	25,000	908	25,000		4
	25,448	930	25,448		5
	6,050	921	6,050		6
	13,795	930	13,795		7
	24,923	188	24,923	24,923	8
	22,072	188	22,072	22,072	9
	102,440	930	102,440		10
	97,500	930	97,500		11
	35,310	930	35,310		12
	9,280	930	9,280		13
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			3,063,678		36
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	28,042,130		
4	Transmission	4,777,503		
5	Regional Market			
6	Distribution	9,935,879		
7	Customer Accounts	12,088,541		
8	Customer Service and Informational	1,086,053		
9	Sales			
10	Administrative and General	27,026,509		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	82,956,615		
12	Maintenance			
13	Production	16,242,713		
14	Transmission	1,162,737		
15	Regional Market			
16	Distribution	6,073,904		
17	Administrative and General	599,698		
18	TOTAL Maintenance (Total of lines 13 thru 17)	24,079,052		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	44,284,843		
21	Transmission (Enter Total of lines 4 and 14)	5,940,240		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	16,009,783		
24	Customer Accounts (Transcribe from line 7)	12,088,541		
25	Customer Service and Informational (Transcribe from line 8)	1,086,053		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	27,626,207		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	107,035,667	29,676,741	136,712,408
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
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)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	107,035,667	29,676,741	136,712,408
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	25,849,559	20,457,979	46,307,538
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	25,849,559	20,457,979	46,307,538
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,724,700	1,323,938	3,048,638
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,724,700	1,323,938	3,048,638
77	Other Accounts (Specify, provide details in footnote):			
78	Account Receivable (work done for others)	910,809	256,405	1,167,214
79	Deferred Debits	3,596,625	1,024,316	4,620,941
80	Certain Civic, Political and Related Activities and Other	355,010	102,797	457,807
81	Accounts Receivable (Non-jurisdictional - Trimble County)	1,944,418	527,847	2,472,265
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,806,862	1,911,365	8,718,227
96	TOTAL SALARIES AND WAGES	141,416,788	53,370,023	194,786,811

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)		20,589	43,329	63,147
3	Net Sales (Account 447)	166,292	571,094	2,340,504	2,891,020
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
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45					
46	TOTAL	166,292	591,683	2,383,833	2,954,167

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	416,487	MWH	172,243	3,710,923	MWH	814,830
2	Reactive Supply and Voltage	416,487	MWH	151,916	3,710,923	MWH	606,408
3	Regulation and Frequency Response				1,509,319	MWH	115,065
4	Energy Imbalance	2,937	MWH	93,292			
5	Operating Reserve - Spinning				1,509,319	MWH	178,351
6	Operating Reserve - Supplement				1,509,319	MWH	178,351
7	Other			1,369			1,647
8	Total (Lines 1 thru 7)	835,911		418,820	11,949,803		1,894,652

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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
Kentucky Utilities 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	5,896	8	8	4,860	548	419		69	
2	February	6,416	20	8	5,112	566	419		319	
3	March	5,165	6	8	4,261	485	419			
4	Total for Quarter 1				14,233	1,599	1,257		388	
5	April	3,416	9	15	2,716	281	419			
6	May	4,103	11	14	3,284	400	419			
7	June	4,734	15	16	3,790	525	419			
8	Total for Quarter 2				9,790	1,206	1,257			
9	July	4,712	29	15	3,807	490	415			
10	August	4,687	3	17	3,724	548	415			
11	September	4,686	4	16	3,756	515	415			
12	Total for Quarter 3				11,287	1,553	1,245			
13	October	3,735	8	16	3,005	315	415			
14	November	4,502	23	8	3,445	437	415		205	
15	December	4,296	4	8	3,456	425	415			
16	Total for Quarter 4				9,906	1,177	1,245		205	
17	Total Year to Date/Year				45,216	5,535	5,004		593	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	19,046,395
3	Steam	17,325,294			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	1,855,381
5	Hydro-Conventional	97,943			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	908,355
7	Other	3,533,296			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	53
9	Net Generation (Enter Total of lines 3 through 8)	20,956,533	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	20,523
10	Purchases	1,732,372	27	Total Energy Losses	1,338,766
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	23,169,473
12	Received	480,568			
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	480,568			
15	Transmission For Other (Wheeling)				
16	Received	3,710,923			
17	Delivered	3,710,923			
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)	23,169,473			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK Megawatts (See Instr. 4)	MONTHLY PEAK Day of Month	MONTHLY PEAK Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,272,699	17,848	4,860	8	800
30	February	2,282,905	62,210	5,112	20	800
31	March	1,911,710	20,226	4,261	6	800
32	April	1,562,129	2,840	2,753	24	700
33	May	1,806,173	61,808	3,343	11	1300
34	June	2,028,242	118,258	3,790	15	1500
35	July	2,201,548	185,368	3,865	28	1400
36	August	2,068,112	137,046	3,784	4	1500
37	September	1,900,502	125,478	3,787	3	1700
38	October	1,665,186	33,968	3,005	8	1600
39	November	1,652,154	39,617	3,445	23	800
40	December	1,818,113	103,688	3,456	4	800
41	TOTAL	23,169,473	908,355			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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: *Green River* (b)			Plant Name: *EW Brown* (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	1950			1957		
4	Year Last Unit was Installed	1959			1971		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	189.00			757.00		
6	Net Peak Demand on Plant - MW (60 minutes)	167			689		
7	Plant Hours Connected to Load	5266			5902		
8	Net Continuous Plant Capability (Megawatts)	161			682		
9	When Not Limited by Condenser Water	161			682		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	25			154		
12	Net Generation, Exclusive of Plant Use - KWh	656724000			2032750000		
13	Cost of Plant: Land and Land Rights	30764			2570670		
14	Structures and Improvements	8667845			75206507		
15	Equipment Costs	3696732			903672012		
16	Asset Retirement Costs	53600570			29382094		
17	Total Cost	65995911			1010831283		
18	Cost per KW of Installed Capacity (line 17/5) Including	349.1847			1335.3121		
19	Production Expenses: Oper, Supv, & Engr	1152969			2678040		
20	Fuel	17653098			71383653		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1021683			4768052		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	715903			2201074		
26	Misc Steam (or Nuclear) Power Expenses	1001978			4043724		
27	Rents	0			12000		
28	Allowances	8880			2003		
29	Maintenance Supervision and Engineering	885936			1896020		
30	Maintenance of Structures	522508			1668909		
31	Maintenance of Boiler (or reactor) Plant	2447289			8306936		
32	Maintenance of Electric Plant	419329			5374289		
33	Maintenance of Misc Steam (or Nuclear) Plant	626510			884543		
34	Total Production Expenses	26456083			103219243		
35	Expenses per Net KWh	0.0403			0.0508		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	barrels		tons	barrels	
38	Quantity (Units) of Fuel Burned	325894	3270	0	1028316	8060	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11570	3333	0	11470	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	53.030	84.432	0.000	65.730	108.930	0.000
41	Average Cost of Fuel per Unit Burned	52.222	84.432	0.000	68.564	108.930	0.000
42	Average Cost of Fuel Burned per Million BTU	2.257	14.359	0.000	2.989	18.526	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.035	0.000	0.000
44	Average BTU per KWh Net Generation	11483.000	0.000	0.000	11605.000	0.000	0.000

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Kentucky Utilities 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: *Ghent* (d)	Plant Name: *Trimble County* (e)	Plant Name: (f)	Line No.
Steam	Steam		1
Conventional	Conventional		2
1973	2011		3
1984	2011		4
2226.00	509.00	0.00	5
1941	626	0	6
7256	7312	0	7
1919	445	0	8
1919	445	0	9
0	0	0	10
270	188	0	11
11367897000	4373516000	0	12
20249182	6841	0	13
145758455	105652801	0	14
2710935935	756414527	0	15
181705935	44673918	0	16
3058649507	906748087	0	17
1374.0564	1781.4304	0	18
5048258	2044408	0	19
274534521	95620294	0	20
0	0	0	21
14854366	3023821	0	22
0	0	0	23
0	0	0	24
4607579	986728	0	25
20736586	6448067	0	26
0	0	0	27
7343	2	0	28
5581210	589847	0	29
4826002	964271	0	30
28520739	7113257	0	31
10110902	903136	0	32
888696	811114	0	33
369716202	118504945	0	34
0.0325	0.0271	0.0000	35

(d)			(e)			(f)			Line No.
Coal	Oil		Coal	Oil					36
tons	barrels		tons	barrels					37
5454268	25988	0	1884191	21895	0	0	0	0	38
11273	3333	0	10673	3333	0	0	0	0	39
49.340	93.973	0.000	50.810	58.210	0.000	0.000	0.000	0.000	40
49.905	93.973	0.000	37.140	58.210	0.000	0.000	0.000	0.000	41
2.214	15.982	0.000	1.740	9.900	0.000	0.000	0.000	0.000	42
0.024	0.000	0.000	0.016	0.000	0.000	0.000	0.000	0.000	43
10817.000	0.000	0.000	9196.000	0.000	0.000	0.000	0.000	0.000	44

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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: *Haefling* (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)	Outdoor			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	41.00			781.00		
6	Net Peak Demand on Plant - MW (60 minutes)	27			709		
7	Plant Hours Connected to Load	115			1181		
8	Net Continuous Plant Capability (Megawatts)	24			814		
9	When Not Limited by Condenser Water	24			814		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	2209000			592527000		
13	Cost of Plant: Land and Land Rights	0			272805		
14	Structures and Improvements	291451			12003771		
15	Equipment Costs	4075508			268086654		
16	Asset Retirement Costs	0			227200		
17	Total Cost	4366959			280590430		
18	Cost per KW of Installed Capacity (line 17/5) Including	106.5112			359.2707		
19	Production Expenses: Oper, Supv, & Engr	0			222733		
20	Fuel	428816			19623207		
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	14663			331133		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			14880		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			44758		
30	Maintenance of Structures	0			492111		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	58414			1762234		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	501893			22491056		
35	Expenses per Net KWh	0.2272			0.0380		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf	barrels		mcf	barrels	
38	Quantity (Units) of Fuel Burned	47401	0	0	7028824	4116	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1025	3333	0	1025	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	9.046	84.840	0.000	2.731	104.026	0.000
41	Average Cost of Fuel per Unit Burned	9.046	84.840	0.000	2.731	104.026	0.000
42	Average Cost of Fuel Burned per Million BTU	8.826	0.000	0.000	2.664	17.691	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.194	0.000	0.000	0.032	0.240	0.000
44	Average BTU per KWh Net Generation	21995.000	0.000	0.000	12196.000	13589.000	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: *Paddy's Run 13 CT* (d)	Plant Name: *Trimble County CT* (e)	Plant Name: *Cane Run NGCC* (f)	Line No.
Combustion Turbine	Combustion Turbine	Steam	1
Conventional	Conventional	Conventional	2
2001	2002	2015	3
2001	2004	2015	4
84.00	784.00	808.00	5
60	707	606	6
453	1186	4075	7
69	626	521	8
69	626	521	9
0	0	0	10
0	0	57	11
85061000	662133000	2191366000	12
6286	26174	6243	13
2136303	21745929	46895474	14
30595718	218291825	364521140	15
0	101768	74376	16
32738307	240165696	411497233	17
389.7418	306.3338	509.2788	18
0	0	468269	19
2988127	39070278	43794851	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
18158	334241	2391208	25
0	0	0	26
10774	-256	0	27
0	0	0	28
7935	0	43578	29
3236	0	136712	30
0	0	0	31
308339	1047419	2294602	32
0	0	0	33
3336569	40451682	49129220	34
0.0392	0.0611	0.0224	35

(d)			(e)			(f)			Line No.
Gas			Gas			Gas			36
mcf			mcf			mcf			37
908690	0	0	7119401	0	0	15143245	0	0	38
1012	0	0	1017	0	0	1010	0	0	39
3.288	0.000	0.000	5.488	0.000	0.000	2.892	0.000	0.000	40
3.288	0.000	0.000	5.488	0.000	0.000	2.892	0.000	0.000	41
3.250	0.000	0.000	5.398	0.000	0.000	2.863	0.000	0.000	42
0.035	0.000	0.000	0.059	0.000	0.000	0.020	0.000	0.000	43
10809.000	0.000	0.000	10931.000	0.000	0.000	6980.000	0.000	0.000	44

Name of Respondent Kentucky Utilities 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: 402 Line No.: -1 Column: b
Green River Generating Station was fully retired in September 2015.

Schedule Page: 403 Line No.: -1 Column: e
Partnership Expenses included in Column f:

Line No.: 19	Production Expenses: Oper, Supv & Engr	$	(511,103)
Line No.: 20	Fuel		(24,194,165)
Line No.: 22	Steam Expenses		(759,578)
Line No.: 25	Electric Expenses		(246,682)
Line No.: 26	Misc Steam Power Expenses		(1,612,018)
Line No.: 28	Allowances		(1)
Line No.: 29	Maintenance Supervision and Engineering		(147,462)
Line No.: 30	Maintenance of Structures		(241,068)
Line No.: 31	Maintenance of Boiler Plant		(1,779,918)
Line No.: 32	Maintenance of Electric Plant		(225,784)
Line No.: 33	Maintenance of Misc Steam Plant		(202,779)
Line No.: 34	Total Production Expenses	$	(29,920,558)

Total Power Production Expenses per Schedule Page: 402-403, Sum of Line No.: 34, Column: b-f	$	733,806,893
IMEA-IMPA Partnership Expenses		(29,920,558)
Total Power Production Expenses per Schedule Page: 320-321, Sum of Line No.: 21 & 74, Column: b	$	703,886,335

Schedule Page: 403 Line No.: -1 Column: f
Pineville Generating Station was fully retired. However, land and ashpond assets amounting to $7,157,483 remain on the books.

Tyrone Generating Station was fully retired in February 2013. However, land, structures and ashpond assets amounting to $16,165,516 remain on the books. $376,130 of operation and maintenance expenses was incurred related to facility upkeep in 2015.

Schedule Page: 403 Line No.: 5 Column: e
The Nameplate Rating for Trimble County Steam Unit 2 represents a 60.75% ownership for KU. Total Nameplate Rating for the unit is 838 MW. The remaining percentage is owned by LG&E, IMEA and IMPA.

Schedule Page: 402.1 Line No.: 5 Column: c
The Nameplate Rating for Brown CT represents a 47% ownership of Unit 5, a 123 MW unit, and 62% ownership of Units 6 and 7, which are 177 MW each, for KU. The remaining percentages of Units 5, 6 and 7 are owned by LG&E.

Schedule Page: 403.1 Line No.: 5 Column: d
The Nameplate Rating for Paddy's Run 13 CT represents a 47% ownership for KU. Total Nameplate Rating for the unit is 178 MW. The remaining percentage is owned by LG&E.

Schedule Page: 403.1 Line No.: 5 Column: e
The Nameplate Rating for Trimble County CT represents a 71% ownership of Units 5 and 6 and 63% of Units 7, 8, 9 and 10 for KU. Total Nameplate Ratings for these units are 199 MW per unit. The remaining percentages for Units 5, 6, 7, 8, 9 and 10 are owned by LG&E.

Schedule Page: 403.1 Line No.: 5 Column: f
The Nameplate Rating for Cane Run NGCC Unit 7 represents a 78% ownership for KU. Total Nameplate Rating for the unit is 808 MW per unit. The remaining percentage is owned by LG&E.

Schedule Page: 402.1 Line No.: 11 Column: b
No production/operation employees are directly assigned to Haefling turbines. Employees from the Brown Plant operate and maintain the Haefling turbines.

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

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FOOTNOTE DATA

site and are reflected in the Brown Steam Plant statistics.

Schedule Page: 403.1 Line No.: 11 Column: d

No production/operation employees are directly assigned to Paddy's Run turbines. Employees from the LG&E Cane Run Plant operate and maintain the Paddy's Run turbines.

Schedule Page: 403.1 Line No.: 11 Column: e

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.

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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. 0 Plant Name: Dix Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1923	
4	Year Last Unit was Installed	1924	
5	Total installed cap (Gen name plate Rating in MW)	34.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	32	0
7	Plant Hours Connect to Load	3,511	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	32	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	3	0
12	Net Generation, Exclusive of Plant Use - Kwh	97,943,000	0
13	Cost of Plant		
14	Land and Land Rights	879,312	0
15	Structures and Improvements	827,602	0
16	Reservoirs, Dams, and Waterways	21,885,646	0
17	Equipment Costs	15,697,533	0
18	Roads, Railroads, and Bridges	234,509	0
19	Asset Retirement Costs	274,310	0
20	TOTAL cost (Total of 14 thru 19)	39,798,912	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,170.5562	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	60,343	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	130,012	0
30	Maintenance of Structures	810,430	0
31	Maintenance of Reservoirs, Dams, and Waterways	6,398	0
32	Maintenance of Electric Plant	44,739	0
33	Maintenance of Misc Hydraulic Plant	5,405	0
34	Total Production Expenses (total 23 thru 33)	1,057,327	0
35	Expenses per net KWh	0.0108	0.0000

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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
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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.
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	Pocket	Pineville	500.00	500.00	ST	35.48		
2	Pocket	Phipps Bend	500.00	500.00	ST	21.39		
3	Ghent Plant	Brown North	345.00	345.00	ST	113.87		
4	Ghent Plant	Batesville	345.00	345.00	ST	7.80		
5	Brown Plant	Elmer Smith	345.00	345.00	HF,SP,ST	171.06		
6	Brown North	K.U. Park	345.00	345.00	ST	102.47		2
7	Green River	AEC Buss	161.00	161.00	HF,ST,WP	183.09		
8	Green River	Morganfield	161.00	161.00	HF,WP	55.38		
9	Elihu	Dorchester	161.00	161.00	HF,ST	86.06		
10	Lake Reba	Dorchester	161.00	161.00	HF,ST	99.15		1
11	Pineville	Harlan	161.00	161.00	HF,WP	48.34		
12	Pineville 149	Pineville 192	161.00	161.00	HF	0.12		1
13	East Ky. Power Cooperative	Taylor County	161.00	161.00	SP	3.97		1
14	Imboden	Harlan	161.00	161.00	HF,SP,WP,ST	43.82		
15	Ghent Plant	Brown Plant	138.00	138.00	ST	90.47		
16	Brown Plant	Green River	138.00	138.00	HF,SP,WP,ST	169.43		
17	Kenton	Rodburn	138.00	138.00	HF	45.74		1
18	Green River	Brown North	138.00	138.00	HF,SP,ST	166.68		
19	Fawkes	Rodburn	138.00	138.00	HF,ST,WP	64.52		1
20	Clifty Creek	Carrollton	138.00	138.00	HF,SP,ST,WP	144.71		
21	Brown Plant	Lake Reba	138.00	138.00	HF,SP	29.44		1
22	Brown Plant	Haefling	138.00	138.00	HF,SP,ST,WP	29.32		
23	Ghent Plant	Kenton Station	138.00	138.00	HF,WF	72.78		1
24	Ghent Plant	Adams	138.00	138.00	HF,SP,ST	56.77		
25	Hardin County	Rogersville	138.00	138.00	HF	10.24		1
26	Virginia City	Clinch River (AEP Int. Pt)	138.00	138.00	HF	7.89		1
27	69KV Lines		69.00	69.00	Various	2,218.11		
28								
29								
30								
31								
32								
33	Exp Applicable to All Lines							
34								
35								
36					TOTAL	4,078.10		11

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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	3,117,591	15,708,717	18,826,308					1
954 mcm	280,371	7,950,059	8,230,430					2
795 mcm	2,495,681	17,199,119	19,694,800					3
954 mcm	437,159	6,116,394	6,553,553					4
954 mcm	5,420,411	63,164,668	68,585,079					5
954 mcm	1,111,580	26,077,449	27,189,029					6
556 mcm	1,284,446	22,321,042	23,605,488					7
556 mcm	268,660	2,138,773	2,407,433					8
556 mcm	264,089	9,783,737	10,047,826					9
556 mcm	559,988	7,805,687	8,365,675					10
795 mcm	300,849	6,888,696	7,189,545					11
954 mcm		163,651	163,651					12
556 mcm	261,988	307,188	569,176					13
795 mcm	84,143	6,535,101	6,619,244					14
954 mcm	419,701	6,470,788	6,890,489					15
556 mcm	450,425	15,504,752	15,955,177					16
397 mcm	98,119	1,924,191	2,022,310					17
795 mcm	734,488	15,384,650	16,119,138					18
556 mcm	579,168	3,647,500	4,226,668					19
795 mcm	891,092	30,687,679	31,578,771					20
556 mcm	80,240	2,031,976	2,112,216					21
795 mcm	191,989	5,132,206	5,324,195					22
795 mcm	446,861	5,574,383	6,021,244					23
795 mcm	245,501	7,018,007	7,263,508					24
795 mcm	245,092	1,219,491	1,464,583					25
795 mcm	344,980	4,788,455	5,133,435					26
Various	8,777,075	192,471,362	201,248,437					27
								28
								29
								30
								31
								32
				711,836	6,125,495	152,237	6,989,568	33
								34
								35
	29,391,687	484,015,721	513,407,408	711,836	6,125,495	152,237	6,989,568	36

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Name of Respondent Kentucky Utilities 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: 422 Line No.: 1 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 2 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 3 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 4 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 5 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 7 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 8 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 9 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 11 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 14 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 15 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 16 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 18 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 20 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 22 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 24 Column: h
Contains both single and double circuitry.
Schedule Page: 422 Line No.: 27 Column: h
Contains both single and double circuitry.

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Kentucky Utilities 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	A. O. Smith - Mt. Sterling	Transmission*	69.00		
2	Adams - Georgetown	Transmission*	138.00	69.00	13.20
3	Alcade - Somerset	Transmission*	345.00	161.00	13.20
4	American Ave. - Lexington	Transmission*	138.00	69.00	13.20
5	Arnold - Cumberland	Transmission*	161.00	69.00	13.20
6	Artemus - Pineville	Transmission*	161.00	69.00	13.20
7	Bardstown - Campbellsville	Transmission*	138.00	69.00	13.20
8	Bardstown City - Campbellsville	Transmission*	69.00		
9	Barlow	Transmission*	69.00		
10	Beattyville - Richmond	Transmission*	161.00	69.00	13.20
11	Bimble	Transmission*	69.00		
12	Blackwell	Transmission*	138.00		
13	Bond - Coeburn	Transmission*	69.00		
14	Bonds Mill	Transmission*	69.00		
15	Bonnieville - Horse Cave	Transmission*	138.00	69.00	13.20
16	Boone Ave. - Winchester	Transmission*	69.00		
17	Boonesboro North - Winchester	Transmission*	138.00	69.00	13.20
18	Boyle County	Transmission*	69.00		
19	Broadhead Switching	Transmission*	69.00		
20	Bromley	Transmission*	69.00		
21	Brown CT - Harrodsburg	Transmission*	138.00		
22	Brown North - Harrodsburg	Transmission*	345.00	138.00	13.20
23	Carntown - Augusta	Transmission*	138.00	69.00	13.20
24	Carrollton - Carrollton	Transmission*	138.00	69.00	13.20
25	Cary Switching	Transmission*	69.00		
26	Clark County - Winchester	Transmission*	138.00	69.00	13.20
27	Clinton	Transmission*	69.00		
28	Coleman Road - McCracken Co.	Transmission*	161.00		
29	Corydon - Henderson	Transmission*	161.00	69.00	13.20
30	Crittendon County - Marion	Transmission*	161.00	69.00	13.20
31	Cynthiana Switching	Transmission*	69.00		
32	Danville North - Danville	Transmission*	138.00	69.00	13.20
33	Daviess County	Transmission*	345.00		
34	Delvinta	Transmission*	161.00		
35	Dow Corning West	Transmission*	138.00		
36	Dorchester - Norton	Transmission*	161.00	69.00	13.20
37	Earlington North - Earlington	Transmission*	161.00	69.00	13.20
38	East Frankfort - Frankfort	Transmission*	138.00	69.00	13.20
39	Elihu - Somerset	Transmission*	161.00	69.00	13.20
40	Elizabethtown - Elizabethtown	Transmission*	138.00	69.00	13.20

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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)	
			NONE			1
186	2		NONE			2
448	1		NONE			3
150	1		NONE			4
56	1		NONE			5
56	1		NONE			6
94	1		NONE			7
			NONE			8
			NONE			9
56	1		NONE			10
			NONE			11
			NONE			12
			NONE			13
			NONE			14
34	1		NONE			15
			NONE			16
150	1		NONE			17
			NONE			18
			NONE			19
			NONE			20
			NONE			21
448	1		NONE			22
50	1		NONE			23
187	2		NONE			24
			NONE			25
93	1		NONE			26
			NONE			27
			NONE			28
112	1		NONE			29
112	1		NONE			30
			NONE			31
112	1		NONE			32
			NONE			33
			NONE			34
			NONE			35
187	2		NONE			36
224	1	1	NONE			37
224	2		NONE			38
187	2		NONE			39
149	1		NONE			40

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Kentucky Utilities 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	Eminence	Transmission*	69.00		
2	Evarts	Transmission*	69.00		
3	Farley - Corbin	Transmission*	161.00	69.00	13.20
4	Farmers - Morehead	Transmission*	80.00	40.00	13.20
5	Fawkes - Richmond	Transmission*	138.00	69.00	13.20
6	Finchville	Transmission*	69.00		
7	FMC - Lexington	Transmission*	69.00		
8	Ghent Plant - Carrollton	Transmission*	345.00	138.00	
9	Ghent Plant - Carrollton	Transmission*	345.00	138.00	25.00
10	Goddard	Transmission*	138.00		
11	Gorge Switching	Transmission*	69.00		
12	Grahamville - Barlow	Transmission*	161.00	69.00	13.20
13	Green River Plant - Greenville	Transmission*	138.00	69.00	13.20
14	Green River Plant - Greenville	Transmission*	161.00	138.00	13.20
15	Green River Steel - Greenville	Transmission*	138.00	69.00	13.20
16	Haefling - Lexington	Transmission*	138.00	69.00	13.20
17	Hardin County - Elizabethtown	Transmission*	345.00	138.00	13.20
18	Hardin County - Elizabethtown	Transmission*	138.00	69.00	13.20
19	Hardinsburg - Hardinsburg	Transmission*	138.00		
20	Harrodsburg	Transmission*	69.00		
21	Harlan "Y" - Harlan	Transmission*	161.00	69.00	13.20
22	Higby Mill - Lexington	Transmission*	138.00	69.00	13.20
23	Hillside	Transmission*	69.00		
24	Howards Branch	Transmission*	161.00		
25	Hughes Lane - Lexington	Transmission*	69.00		
26	Imboden - Big Stone Gap	Transmission*	161.00	69.00	13.20
27	Indian Hill	Transmission*	69.00		
28	Kenton - Maysville	Transmission*	138.00	69.00	13.20
29	KU Park - Pineville	Transmission*	69.00		
30	LaGrange East	Transmission*	69.00		
31	Lake Reba - Richmond	Transmission*	138.00	69.00	13.20
32	Lake Reba Tap - Richmond	Transmission*	161.00	138.00	6.60
33	Lancaster Switching	Transmission*	69.00		
34	Lansdowne - Lexington	Transmission*	138.00	69.00	13.20
35	Lebanon - Lebanon	Transmission*	80.00	40.00	13.20
36	Lebanon City	Transmission*	69.00		
37	Leitchfield - Leitchfield	Transmission*	138.00	69.00	13.20
38	Leitchfield East	Transmission*	69.00		
39	Lexington Plant - Lexington	Transmission*	69.00		
40	Livingston County	Transmission*	161.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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
			NONE			2
149	1		NONE			3
40	3		NONE			4
299	2		NONE			5
			NONE			6
			NONE			7
450	1	1	NONE			8
448	1		NONE			9
			NONE			10
			NONE			11
93	1		NONE			12
261	2		NONE			13
312	3		NONE			14
93	1		NONE			15
149	1		NONE			16
448	1		NONE			17
149	1		NONE			18
			NONE			19
			NONE			20
94	1		NONE			21
344	3	1	NONE			22
			NONE			23
			NONE			24
			NONE			25
149	1		NONE			26
			NONE			27
145	2		NONE			28
		1	NONE			29
			NONE			30
149	1		NONE			31
200	1		NONE			32
			NONE			33
112	1		NONE			34
100	6		NONE			35
			NONE			36
93	1		NONE			37
			NONE			38
			NONE			39
			NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	London - London	Transmission*	69.00		
2	Loudon Ave - Lexington	Transmission*	138.00	69.00	13.20
3	Lynch - Harlan	Transmission*	69.00		
4	Manchester	Transmission*	69.00		
5	Marion	Transmission*	69.00		
6	Matanzas	Transmission*	161.00	138.00	13.20
7	Meldrum Switching	Transmission*	69.00		
8	Middlesboro - Middlesboro	Transmission*	69.00		
9	Millersburg - Millersburg	Transmission*	69.00		
10	Morganfield - Morganfield	Transmission*	161.00	69.00	13.20
11	Mt. Vernon - Mt. Vernon	Transmission*	69.00		
12	N.A.S.	Transmission*	345.00	138.00	
13	Nebo - Nebo	Transmission*	69.00		
14	Nicholasville	Transmission*	69.00		
15	North London - London	Transmission*	69.00		
16	North Princeton - Princeton	Transmission*	161.00		
17	Ohio County - Beaver Dam	Transmission*	138.00	69.00	13.20
18	Paducah Primary - Paducah	Transmission*	161.00		
19	Paris	Transmission*	138.00	69.00	13.20
20	Pineville - Pineville	Transmission*	345.00	161.00	13.20
21	Pineville - Pineville	Transmission*	500.00	345.00	34.50
22	Pineville - Pineville	Transmission*	161.00	69.00	13.20
23	Pineville Switching - Pineville	Transmission*	161.00		
24	Pisgah - Lexington	Transmission*	138.00	69.00	13.20
25	Pittsburg - London	Transmission*	161.00	69.00	13.20
26	Pocket - Pennington Gap	Transmission*	161.00	69.00	13.20
27	Pocket North - Pennington Gap	Transmission*	500.00	161.00	
28	Princeton - Princeton	Transmission*	69.00		
29	Richmond - Richmond	Transmission*	69.00		
30	River Queen - Muhlenberg	Transmission*	161.00	69.00	13.20
31	Rocky Branch	Transmission*	69.00		
32	Rodburn - Morehead	Transmission*	138.00	69.00	13.20
33	Rogersville - Radcliff	Transmission*	138.00	69.00	13.20
34	Scott County	Transmission*	138.00	69.00	13.20
35	Shelbyville - Shelbyville	Transmission*	69.00		
36	Simmons	Transmission*	69.00		
37	Somerset North - Somerset	Transmission*	69.00		
38	South Paducah	Transmission*	161.00	69.00	13.20
39	Spears Switching	Transmission*	69.00		
40	Spencer Road - Mt. Sterling	Transmission*	138.00	69.00	13.20

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Kentucky Utilities 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
262	2	1	NONE			2
			NONE			3
			NONE			4
			NONE			5
400	2		NONE			6
			NONE			7
			NONE			8
			NONE			9
112	1		NONE			10
			NONE			11
450	1		NONE			12
			NONE			13
			NONE			14
			NONE			15
			NONE			16
93	1	3	NONE			17
		3	NONE			18
150	1		NONE			19
560	1		NONE			20
504	1		NONE			21
299	2		NONE			22
			NONE			23
112	1		NONE			24
112	1		NONE			25
187	1		NONE			26
448	1		NONE			27
			NONE			28
			NONE			29
93			NONE			30
			NONE			31
61	1		NONE			32
93	1		NONE			33
93	1		NONE			34
			NONE			35
			NONE			36
			NONE			37
50	1		NONE			38
			NONE			39
89	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	St. Paul	Transmission*	69.00		
2	Stanford North	Transmission*	69.00		
3	Sweet Hollow	Transmission*	69.00		
4	Taylor County - Campbellsville	Transmission*	161.00	69.00	13.20
5	Tyrone - Versailles	Transmission*	138.00	69.00	13.20
6	UK Medical Center - Lexington	Transmission*	69.00		
7	Uniontown	Transmission*	69.00		
8	Versailles Bypass - Versailles	Transmission*	69.00		
9	Virginia City - Norton	Transmission*	138.00	69.00	13.20
10	Walker - Earlington	Transmission*	161.00	69.00	13.20
11	West Cliff - Harrodsburg	Transmission*	138.00	69.00	13.20
12	West Frankfort - Shelbyville	Transmission*	345.00	138.00	13.20
13	West Frankfort - Shelbyville	Transmission*	138.00	69.00	13.20
14	West Garrard - Lancaster	Transmission*	345.00		
15	West Irvine - Irvine	Transmission*	161.00	69.00	13.20
16	West Lexington - Lexington	Transmission*	345.00	138.00	13.20
17	Wheatcroft	Transmission*	69.00		
18	Wickliffe - Barlow	Transmission*	161.00	69.00	13.20
19	Williamsburg Switching	Transmission*	69.00		
20	Winchester	Transmission*	69.00		
21	Wofford	Transmission*	69.00		
22	Total Transmission		19215.00	6083.00	924.10
23					
24	A.O. Smith - Mt. Sterling	Distribution*	69.00	12.47	
25	Adams	Distribution*	69.00	34.50	
26	Adams	Distribution*	69.00	12.47	
27	Airgas	Distribution*	138.00	13.80	
28	Aisin	Distribution*	69.00	12.47	
29	Alexander - Versailles	Distribution*	69.00	12.47	
30	American Ave. - Lexington	Distribution*	69.00	4.16	
31	Andover - Norton	Distribution*	69.00	34.50	
32	Appalachia	Distribution*	69.00	12.47	
33	Ashland Ave. - Lexington	Distribution*	69.00	4.16	
34	Ashland Pipe - Lexington	Distribution*	69.00	12.47	
35	Atoka	Distribution*	69.00	12.47	
36	Augusta 12KV	Distribution*	69.00	12.47	
37	Bardstown City	Distribution*	69.00	12.47	
38	Bardstown Industrial	Distribution*	69.00	12.47	
39	Barlow	Distribution*	69.00	12.47	
40	Beaver Dam - Beaver Dam	Distribution*	69.00	12.47	

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Kentucky Utilities 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.
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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)	
			NONE			1
			NONE			2
			NONE			3
90	1		NONE			4
112	1		NONE			5
			NONE			6
			NONE			7
			NONE			8
120	1		NONE			9
112	1		NONE			10
392	3		NONE			11
450	1		NONE			12
112	1		NONE			13
			NONE			14
56	1		NONE			15
448	1		NONE			16
			NONE			17
93	1		NONE			18
			NONE			19
			NONE			20
			NONE			21
13745	95	11				22
						23
22	1		NONE			24
20	1		NONE			25
22	1		NONE			26
22	1		NONE			27
14	1		NONE			28
22	1		NONE			29
14	1		NONE			30
37	1		NONE			31
11	1		NONE			32
28	2		NONE			33
20	2		NONE			34
14	1		NONE			35
14	1		NONE			36
22	1		NONE			37
45	2		NONE			38
11	1		NONE			39
14	1		NONE			40

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

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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	Beaver Dam North - Beaver Dam	Distribution*	69.00	12.47	
2	Belt Line - Lexington	Distribution*	69.00	12.47	
3	Bevier - Earlington	Distribution*	69.00	34.50	
4	Big Stone Gap - Big Stone Gap	Distribution*	69.00	12.47	
5	Black Branch Road	Disatribution*	138.00	12.47	
6	Bond - Coeburn	Distribution*	69.00	12.47	
7	Bond - Coeburn	Distribution*	69.00	23.00	
8	Boone Ave. - Winchester	Distribution*	69.00	12.47	
9	Boonesboro Park	Distribution*	69.00	12.47	
10	Borg Warner - Earlington	Distribution*	69.00	12.47	
11	Bryant Road - Lexington	Distribution*	69.00	12.47	
12	Buchanan - Lexington	Distribution*	69.00	4.16	
13	Buena Vista	Distribution*	69.00	12.47	
14	Burnside - Somerset	Distribution*	69.00	12.47	
15	Calloway	Distribution*	69.00	12.47	
16	Camargo - Mt. Sterling	Distribution*	69.00	12.47	
17	Camp Breckinridge	Distribution*	69.00	12.47	
18	Campbellsville 1 - Campbellsville	Distribution*	69.00	12.47	
19	Campbellsville Industrial - Campbellsville	Distribution*	69.00	12.47	
20	Carlisle	Distribution*	69.00	12.47	
21	Carntown - Augusta	Distribution*	69.00	12.47	
22	Caron - London	Distribution*	69.00	12.47	
23	Carrollton - Carrollton	Distribution*	69.00	12.47	
24	Catrons Creek	Distribution*	69.00	12.47	
25	Cawood - Harlan	Distribution*	69.00	12.47	
26	Central City	Distribution*	69.00	12.47	
27	Central City South	Distribution*	69.00	12.47	
28	Clay Mills - Lexington	Distribution*	138.00	12.47	
29	Clinch Valley - Norton	Distribution*	69.00	12.47	
30	Clinton	Distribution*	69.00	12.47	
31	Columbia - Columbia	Distribution*	69.00	12.47	
32	Columbia South - Columbia	Distribution*	69.00	12.47	
33	Corbin East - Corbin	Distribution*	69.00	12.47	
34	Corbin US Steel	Distribution*	69.00	12.47	
35	Corning 12KV	Distribution*	69.00	12.47	
36	Corning Harrodsburg	Distribution*	69.00	12.47	
37	Corporate Drive	Distribution*	69.00	12.47	
38	Cynthiana	Distribution*	69.00	12.47	
39	Cynthiana South	Distribution*	67.00	12.47	
40	Danville Central - Danville	Distribution*	69.00	12.47	

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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.
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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.
14	1		NONE			1
22	1		NONE			2
14	2		NONE			3
42	3		NONE			4
28	1		NONE			5
45	2		NONE			6
22	1		NONE			7
22	1		NONE			8
11	1		NONE			9
22	1		NONE			10
67	3		NONE			11
14	1		NONE			12
14	1		NONE			13
14	1		NONE			14
11	1		NONE			15
28	2		NONE			16
14	1		NONE			17
45	2		NONE			18
22	1		NONE			19
14	2		NONE			20
22	1		NONE			21
22	1		NONE			22
19	2		NONE			23
11	1		NONE			24
14	1		NONE			25
14	1		NONE			26
14	1		NONE			27
37	1		NONE			28
22	1		NONE			29
11	1		NONE			30
14	1		NONE			31
14	1		NONE			32
36	2		NONE			33
11	1		NONE			34
62	5		NONE			35
15	7		NONE			36
29	2		NONE			37
20	2		NONE			38
14	1		NONE			39
29	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Danville East - Danville	Distribution*	69.00	12.47	
2	Danville Industrial - Danville	Distribution*	69.00	12.47	
3	Danville North - Danville	Distribution*	69.00	12.47	
4	Danville West - Danville	Distribution*	69.00	12.47	
5	Dark Hollow - Richmond	Distribution*	69.00	12.47	
6	Dawson Industrial - Earlington	Distribution*	69.00	4.16	
7	Dayhoit	Distribution*	69.00	12.47	
8	Days Branch	Distribution*	69.00	12.47	
9	Dayton - Walther - Carrollton	Distribution*	138.00	12.47	
10	Delaplain - Georgetown	Distribution*	69.00	12.47	
11	Delaplain - Georgetown	Distribution*	69.00	13.80	
12	Denham Street - Somerset	Distribution*	69.00	12.47	
13	Detroit Harvester - Paris	Distribution*	69.00	12.47	
14	Donerail - Lexington	Distribution*	69.00	12.47	
15	Dorchester - Norton	Distribution*	69.00	22.00	
16	Dorchester - Norton	Distribution*	69.00	34.50	
17	Dorchester - Norton	Distribution*	69.00	12.47	
18	Dow Corning - Carrollton	Distribution*	69.00	12.47	
19	Dozier Heights	Distribution*	69.00	12.47	
20	Earlington - Earlington	Distribution*	69.00	34.50	
21	Earlington - Earlington	Distribution*	69.00	12.47	
22	East Bernstadt - London	Distribution*	69.00	12.47	
23	East Stone - Big Stone Gap	Distribution*	69.00	12.47	
24	Eastland - Lexington	Distribution*	69.00	12.47	
25	Eastview	Distribution*	69.00	12.47	
26	Eddyville	Distribution*	69.00	12.47	
27	Eddyville Prison	Distribution*	69.00	12.47	
28	Elizabethtown Industrial - Elizabethtown	Distribution*	69.00	12.47	
29	Eminence - Shelbyville	Distribution*	69.00	12.47	
30	Esserville - Norton	Distribution*	69.00	12.47	
31	Etown #2 - Elizabethtown	Distribution*	69.00	12.47	
32	Etown #3 - Elizabethtown	Distribution*	69.00	12.47	
33	Etown #4 - Elizabethtown	Distribution*	69.00	12.47	
34	Etown #5 - Elizabethtown	Distribution*	69.00	12.47	
35	Etown West - Elizabethtown	Distribution*	69.00	12.47	
36	Evarts	Distribution*	69.00	12.47	
37	Ewington - Mt. Sterling	Distribution*	69.00	12.47	
38	Fairfield - Fairfield	Distribution*	69.00	12.47	
39	Farmers	Distribution*	69.00	12.47	
40	Ferguson South - Somerset	Distribution*	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
29	2		NONE			1
45	2		NONE			2
14	1		NONE			3
22	1		NONE			4
14	1		NONE			5
14	1		NONE			6
11	1		NONE			7
14	1		NONE			8
14	1		NONE			9
14	1		NONE			10
28	1		NONE			11
14	1		NONE			12
22	1		NONE			13
14	1		NONE			14
28	1		NONE			15
14	1		NONE			16
14	1		NONE			17
14	1		NONE			18
14	1		NONE			19
20	1		NONE			20
14	1		NONE			21
14	1		NONE			22
25	2		NONE			23
22	1		NONE			24
11	1		NONE			25
14	1		NONE			26
11	1		NONE			27
22	1		NONE			28
28	2		NONE			29
22	1		NONE			30
45	2		NONE			31
33	2		NONE			32
22	1		NONE			33
14	1		NONE			34
22	1		NONE			35
11	1		NONE			36
36	2		NONE			37
14	1		NONE			38
11	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Flemingsburg	Distribution*	138.00	12.47	
2	Florida Tile - Lawrenceburg	Distribution*	69.00	12.47	
3	FMC - Lexington	Distribution*	69.00	12.47	
4	Forrestdale	Distribution*	69.00	12.47	
5	Forks of Elkhorn - Georgetown	Distribution*	34.50	12.47	
6	Frankfort - Frankfort	Distribution*	69.00	34.50	
7	Gates Rubber	Distribution*	69.00	2.40	
8	GE Lamp Works - Lexington	Distribution*	69.00	4.16	
9	Georgetown - Georgetown	Distribution*	69.00	12.47	
10	Ghent Plant	Distribution*	138.00	13.20	
11	Green River Steel	Distribution*	69.00	12.47	
12	Green River	Distribution*	69.00	34.50	
13	Greensburg - Campbellsville	Distribution*	69.00	12.47	
14	Greenville 12KV - Muhlenburg	Distribution*	69.00	12.47	
15	Greenville 4KV - Muhlenburg	Distribution*	69.00	4.16	
16	Greenville North - Muhlenburg	Distribution*	69.00	12.47	
17	Haefling - Lexington	Distribution*	138.00	12.47	
18	Haley - Lexington	Distribution*	69.00	12.47	
19	Hamblin - Pennington Gap	Distribution*	69.00	12.47	
20	Hanson - Earlington	Distribution*	69.00	12.47	
21	Hardesty - Earlington	Distribution*	69.00	34.50	
22	Harlan - Harlan	Distribution*	69.00	12.47	
23	Harlan Wye - Harlan	Distribution*	69.00	12.47	
24	Harrodsburg East - Harrodsburg	Distribution*	69.00	12.47	
25	Harrodsburg Industrial - Harrodsburg	Distribution*	69.00	12.47	
26	Harrodsburg North	Distribution*	69.00	12.47	
27	Hartford	Distribution*	69.00	4.16	
28	Higby Mill - Lexington	Distribution*	138.00	12.47	
29	Higby Mill - Lexington	Distribution*	69.00	12.47	
30	Highsplint - Harlan	Distribution*	69.00	12.47	
31	Hodgenville 12KV	Distribution*	69.00	12.47	
32	Hoover 1 - Georgetown	Distribution*	69.00	12.47	
33	Hopewell - Corbin	Distribution*	69.00	12.47	
34	Horse Cave	Distribution*	69.00	12.47	
35	Horse Cave Industrial - Horse Cave	Distribution*	69.00	12.47	
36	Hughes Lane - Lexington	Distribution*	69.00	12.47	
37	Hume Road	Distribution*	69.00	12.47	
38	IBM - Lexington	Distribution*	69.00	12.47	
39	IBM North	Distribution*	138.00	12.47	
40	Imboden - Norton	Distribution*	69.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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)	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)	
14	1		NONE			1
14	1		NONE			2
22	1		NONE			3
14	1		NONE			4
14	1		NONE			5
20	1		NONE			6
11	1		NONE			7
14	1		NONE			8
21	2		NONE			9
56	2		NONE			10
25	2		NONE			11
17	1		NONE			12
14	1		NONE			13
14	1		NONE			14
11	1		NONE			15
14	1		NONE			16
39	1		NONE			17
14	1		NONE			18
14	1		NONE			19
22	1		NONE			20
13	1		NONE			21
21	2		NONE			22
28	2		NONE			23
20	2		NONE			24
14	1		NONE			25
14	1		NONE			26
11	1		NONE			27
37	1		NONE			28
22	1		NONE			29
14	1		NONE			30
19	2		NONE			31
22	1		NONE			32
28	2		NONE			33
28	2		NONE			34
45	2		NONE			35
14	1		NONE			36
22	1		NONE			37
75	2		NONE			38
34	1		NONE			39
37	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Innovation Drive	Distribution*	138.00	12.47	
2	Irvine - Richmond	Distribution*	69.00	12.47	
3	Joseph	Distribution*	69.00	4.16	
4	Joyland - Lexington	Distribution*	69.00	12.47	
5	Kawneer - Cynthiana	Distribution*	69.00	12.47	
6	Kentenia	Distribution*	69.00	12.47	
7	Kenton - Maysville	Distribution*	69.00	12.47	
8	Kentucky State Hospital	Distribution*	69.00	12.47	
9	Kentucky River	Distribution*	69.00	4.16	
10	LaGrange East	Distribution*	69.00	12.47	
11	LaGrange - Penal - LaGrange	Distribution*	69.00	12.47	
12	Lakeshore - Lexington	Distribution*	69.00	12.47	
13	Lancaster - Danville	Distribution*	69.00	4.16	
14	Lansdowne - Lexington	Distribution*	69.00	12.47	
15	Lawrenceburg - Lawrenceburg	Distribution*	69.00	12.47	
16	Lebanon - Lebanon	Distribution*	69.00	12.47	
17	Lebanon East	Distribution*	69.00	12.47	
18	Lebanon Industrial	Distribution*	69.00	12.47	
19	Lebanon South	Distribution*	69.00	12.47	
20	Lebanon Junction	Distribution*	161.00	12.47	
21	Lebanon West	Distribution*	138.00	12.47	
22	Leitchfield - Leitchfield	Distribution*	69.00	12.47	
23	Leitchfield East - Leitchfield	Distribution*	69.00	12.47	
24	Lemons Mill - Georgetown	Distribution*	69.00	12.47	
25	Lexington Water Company	Distribution*	69.00	12.47	
26	Lexington Water Company	Distribution*	69.00	4.16	
27	Lexington Plant - Lexington	Distribution*	69.00	4.16	
28	Liberty - Liberty	Distribution*	69.00	12.47	
29	Liberty Road - Lexington	Distribution*	69.00	12.47	
30	Liggett	Distribution*	69.00	12.47	
31	Lockport	Distribution*	138.00	12.47	
32	London - London	Distribution*	69.00	12.47	
33	Loudon Ave. - Lexington	Distribution*	138.00	12.47	
34	Madisonville GE	Distribution*	69.00	12.47	
35	Madisonville Hospital	Distribution*	69.00	12.47	
36	Madisonville North	Distribution*	69.00	12.47	
37	Madisonville West	Distribution*	69.00	12.47	
38	Madisonville East	Distribution*	69.00	12.47	
39	Manchester South	Distribution*	69.00	12.47	
40	Marion South - Marion	Distribution*	69.00	12.47	

Name of Respondent Kentucky Utilities 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)	
51	2		NONE			1
14	1		NONE			2
11	1		NONE			3
36	2		NONE			4
14	1		NONE			5
11	1		NONE			6
28	2		NONE			7
11	1		NONE			8
35	3		NONE			9
36	2		NONE			10
22	1		NONE			11
37	1		NONE			12
14	1		NONE			13
75	2		NONE			14
45	2		NONE			15
14	1		NONE			16
14	1		NONE			17
11	1		NONE			18
14	1		NONE			19
22	1		NONE			20
14	1		NONE			21
14	1		NONE			22
14	1		NONE			23
45	2		NONE			24
45	2		NONE			25
11	1		NONE			26
28	2		NONE			27
14	1		NONE			28
37	1		NONE			29
11	1		NONE			30
11	1		NONE			31
45	2		NONE			32
37	1		NONE			33
22	1		NONE			34
14	1		NONE			35
22	1		NONE			36
22	1		NONE			37
14	1		NONE			38
14	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Maysville East - Maysville	Distribution*	69.00	4.16	
2	Maysville Mid - Maysville	Distribution*	69.00	4.16	
3	McCoy Avenue	Distribution*	69.00	12.47	
4	McKee Road	Distribution*	69.00	12.47	
5	Meldrum - Middlesboro	Distribution*	69.00	12.47	
6	Metal & Thermit - Carrollton	Distribution*	69.00	12.47	
7	Middlesboro #1	Distribution*	69.00	12.47	
8	Middlesboro #2	Distribution*	69.00	12.47	
9	Midway - Versailles	Distribution*	138.00	12.47	
10	Mill Creek	Distribution*	69.00	12.47	
11	Minor Farm	Distribution*	69.00	12.47	
12	Morehead - Morehead	Distribution*	69.00	12.47	
13	Morehead - Morehead	Distribution*	69.00	4.14	
14	Morehead East - Morehead	Distribution*	69.00	4.14	
15	Morehead West - Morehead	Distribution*	69.00	12.47	
16	Morganfield City - Morganfield	Distribution*	69.00	4.14	
17	Morganfield Industrial - Morganfield	Distribution*	69.00	12.47	
18	Mt. Sterling - Mt. Sterling	Distribution*	69.00	12.47	
19	Mt. Vernon - Mt. Vernon	Distribution*	69.00	12.47	
20	Muhlenburg Prison - Muhlenburg	Distribution*	69.00	12.47	
21	Munfordville	Distribution*	69.00	12.47	
22	New Haven	Distribution*	69.00	12.47	
23	Newtown	Distribution*	69.00	12.47	
24	Norton East - Norton	Distribution*	69.00	12.47	
25	Nortonville	Distribution*	34.50	12.47	
26	Oakhill - Earlington	Distribution*	69.00	34.50	
27	Okonite - Richmond	Distribution*	69.00	12.47	
28	Owingsville	Distribution*	69.00	12.47	
29	Oxford - Georgetown	Distribution*	69.00	12.47	
30	Paris - Paris	Distribution*	69.00	12.47	
31	Parker Seal - Winchester	Distribution*	69.00	12.47	
32	Parkers Mill	Distribution*	69.00	12.47	
33	Pepper Pike - Georgetown	Distribution*	34.50	12.47	
34	Picadome - Lexington	Distribution*	69.00	12.47	
35	Pineville	Distribution*	69.00	12.47	
36	Pocket - Norton	Distribution*	69.00	34.50	
37	Poor Valley - Pennington Gap	Distribution*	69.00	12.47	
38	Powderly - Muhlenburg	Distribution*	69.00	12.47	
39	Princeton - Princeton	Distribution*	69.00	34.50	
40	Proctor & Gamble	Distribution*	69.00	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
11	1		NONE			1
14	1		NONE			2
14	1		NONE			3
14	1		NONE			4
14	1		NONE			5
14	1		NONE			6
35	3		NONE			7
35	3		NONE			8
14	1		NONE			9
11	1		NONE			10
14	1		NONE			11
14	1		NONE			12
11	1		NONE			13
11	1		NONE			14
11	1		NONE			15
11	1		NONE			16
14	1		NONE			17
14	1		NONE			18
14	1		NONE			19
14	1		NONE			20
11	1		NONE			21
11	1		NONE			22
14	1		NONE			23
14	1		NONE			24
14	1		NONE			25
20	1		NONE			26
36	2		NONE			27
14	1		NONE			28
28	2		NONE			29
28	2		NONE			30
22	1		NONE			31
45	2		NONE			32
14	1		NONE			33
45	2		NONE			34
28	2		NONE			35
25	4		NONE			36
14	1		NONE			37
14	1		NONE			38
13	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Race Street - Lexington	Distribution*	69.00	12.47	
2	Race Street - Lexington	Distribution*	69.00	4.16	
3	Radcliff - Radcliff	Distribution*	69.00	12.47	
4	Radcliff South - Radcliff	Distribution*	69.00	12.47	
5	Red House	Distribution*	69.00	12.47	
6	Reynolds - Lexington	Distribution*	138.00	12.47	
7	Richmond	Distribution*	69.00	12.47	
8	Richmond #2	Distribution*	69.00	12.47	
9	Richmond #3 (EKU)	Distribution*	69.00	12.47	
10	Richmond East	Distribution*	69.00	12.47	
11	Richmond Industrial	Distribution*	69.00	12.47	
12	Richmond South	Distribution*	69.00	12.47	
13	Rineyville	Distribution*	69.00	12.47	
14	Robbins	Distribution*	69.00	12.47	
15	Rockwell - Winchester	Distribution*	69.00	12.47	
16	Rogers Gap	Distribution*	69.00	12.47	
17	Rogersville - Radcliff	Distribution*	69.00	12.47	
18	Rose Hill	Distribution*	69.00	12.47	
19	Rumsey - Earlington	Distribution*	69.00	34.50	
20	Russell Springs	Distribution*	69.00	12.47	
21	Salem - Earlington	Distribution*	69.00	34.50	
22	Shadrack	Distribution*	69.00	12.47	
23	Shannon Run	Distribution*	69.00	12.47	
24	Sharon - Augusta	Distribution*	69.00	12.47	
25	Shavers Chapel	Distribution*	69.00	12.47	
26	Shawnee Gas	Distribution*	69.00	12.47	
27	Shelbyville North	Distribution*	69.00	12.47	
28	Shelbyville East	Distribution*	69.00	12.47	
29	Shelbyville South	Distribution*	69.00	12.47	
30	Shun Pike	Distribution*	69.00	12.47	
31	Simpsonville - Shelbyville	Distribution*	69.00	12.47	
32	Somerset #2	Distribution*	69.00	4.16	
33	Somerset #3	Distribution*	69.00	12.47	
34	Somerset South	Distribution*	69.00	12.47	
35	Sonora	Distribution*	69.00	12.47	
36	Springfield - Campbellsville	Distribution*	69.00	12.47	
37	St. Paul	Distribution*	69.00	12.47	
38	Stamping Ground	Distribution*	34.50	12.47	
39	Stanford	Distribution*	69.00	12.47	
40	Stanford North	Distribution*	69.00	12.47	

Name of Respondent Kentucky Utilities 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)	
14	1		NONE			1
21	2		NONE			2
22	1		NONE			3
11	1		NONE			4
14	1		NONE			5
77	2		NONE			6
45	2		NONE			7
22	1		NONE			8
45	2		NONE			9
22	1		NONE			10
22	1		NONE			11
22	1		NONE			12
14	1		NONE			13
11	1		NONE			14
22	1		NONE			15
22	1		NONE			16
22	1		NONE			17
11	1		NONE			18
13	1		NONE			19
14	1		NONE			20
14	1		NONE			21
11	1		NONE			22
14	1		NONE			23
14	1		NONE			24
14	1		NONE			25
15	1		NONE			26
22	1		NONE			27
22	1		NONE			28
36	2		NONE			29
14	1		NONE			30
25	2		NONE			31
14	1		NONE			32
14	1		NONE			33
14	1		NONE			34
11	1		NONE			35
25	2		NONE			36
45	2		NONE			37
14	1		NONE			38
14	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Stonewall - Lexington	Distribution*	69.00	12.47	
2	Sylvania - Winchester	Distribution*	69.00	12.47	
3	Taylorsville - Shelbyville	Distribution*	69.00	12.47	
4	Toms Creek	Distribution*	69.00	4.16	
5	Toyota North	Distribution*	138.00	13.20	
6	Toyota South	Distribution*	138.00	13.20	
7	Trafton Ave. - Lexington	Distribution*	69.00	12.47	
8	Trafton Ave. - Lexington	Distribution*	69.00	4.16	
9	UK Scott Street	Distribution*	69.00	12.47	
10	UK Medical Center - Lexington	Distribution*	69.00	12.47	
11	UK West - Lexington	Distribution*	69.00	13.09	
12	Union Underwear - Russell Springs	Distribution*	69.00	12.47	
13	Vaksdahl Avenue	Distribution*	69.00	12.47	
14	Verda - Harlan	Distribution*	69.00	12.47	
15	Versailles West - Versailles	Distribution*	69.00	12.47	
16	Versailles Bypass - Versailles	Distribution*	69.00	12.47	
17	Viley Road - Lexington	Distribution*	138.00	12.47	
18	Vine Street - Lexington	Distribution*	69.00	12.47	
19	Waco	Distribution*	69.00	12.47	
20	Waitsboro - Somerset	Distribution*	69.00	12.47	
21	Warsaw East - Owenton	Distribution*	69.00	12.47	
22	West Hickman - Lexington	Distribution*	69.00	12.47	
23	West High Street - Lexington	Distribution*	69.00	12.47	
24	Westvaco	Distribution*	69.00	13.80	
25	Whitley	Distribution*	69.00	12.47	
26	Wickliffe	Distribution*	69.00	13.80	
27	Wilson Downing - Lexington	Distribution*	69.00	12.47	
28	Williamsburg South - Williamsburg	Distribution*	69.00	12.47	
29	Wilmore - Versailles	Distribution*	69.00	12.47	
30	Winchester Industrial - Winchester	Distribution*	69.00	12.47	
31	Winchester Water	Distribution*	69.00	12.47	
32	Wise - Norton	Distribution*	69.00	12.47	
33	Woodlawn	Distribution*	69.00	12.47	
34	200 Stations Less Than 10 MVa				
35					
36	Total Distribution		21204.00	3759.96	
37					
38	* Unattended				
39					
40					

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Kentucky Utilities 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.
37	1		NONE			1
26	2		NONE			2
14	1		NONE			3
11	1		NONE			4
84	3		NONE			5
84	3		NONE			6
22	1		NONE			7
14	1		NONE			8
37	1		NONE			9
75	2		NONE			10
42	2		NONE			11
28	2		NONE			12
14	1		NONE			13
14	1		NONE			14
22	1		NONE			15
45	2		NONE			16
39	1		NONE			17
20	2		NONE			18
14	1		NONE			19
14	1		NONE			20
14	1		NONE			21
22	1		NONE			22
28	2		NONE			23
67	3		NONE			24
11	1		NONE			25
14	1		NONE			26
45	2		NONE			27
25	2		NONE			28
18	2		NONE			29
22	1		NONE			30
14	1		NONE			31
22	1		NONE			32
14	1		NONE			33
894	273		NONE			34
						35
7336	657					36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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	Summary				
2	Transmission 138				
3	Distribution 479				
4	Total 617				
5					
6					
7					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities 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.
						1
13745	95	11				2
7336	657					3
21081	752	11				4
						5
						6
						7
						8
						9
						10
						11
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						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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	Louisville Gas and Electric Company	see footnote	8,047,576
3	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote	16,195,556
4	Equipment and Facilities	Louisville Gas and Electric Company	see footnote	797,376
5	Office and Administrative Services	Louisville Gas and Electric Company	see footnote	5,379
6	Materials and Fuels	Louisville Gas and Electric Company	see footnote	232,966
7	Outside Services	Louisville Gas and Electric Company	see footnote	237,141
8	Transmission	Louisville Gas and Electric Company	see footnote	358,144
9				
10	Capital Expenditures	LG&E and KU Services Company	see footnote	37,016,601
11	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	107,959,384
12	Equipment and Facilities	LG&E and KU Services Company	see footnote	13,991,493
13	Office and Administrative Services	LG&E and KU Services Company	see footnote	7,046,737
14	Materials	LG&E and KU Services Company	see footnote	2,612,156
15	Outside Services	LG&E and KU Services Company	see footnote	17,614,960
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Capital Expenditures	Louisville Gas and Electric Company	see footnote	2,263,125
22	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote	1,127,580
23	Equipment and Facilities	Louisville Gas and Electric Company	see footnote	422,150
24	Office and Administrative Services	Louisville Gas and Electric Company	see footnote	55,729
25	Materials and Fuels	Louisville Gas and Electric Company	see footnote	90,054
26	Outside Services	Louisville Gas and Electric Company	see footnote	165,269
27	Transmission	Louisville Gas and Electric Company	see footnote	499,624
28				
29	Capital Expenditures	LG&E and KU Services Company	see footnote	229,549
30	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	821,385
31	Equipment and Facilities	LG&E and KU Services Company	see footnote	397,901
32	Office and Administrative Services	LG&E and KU Services Company	see footnote	37,367
33	Materials	LG&E and KU Services Company	see footnote	1,381
34	Outside Services	LG&E and KU Services Company	see footnote	27,187
35				
36	Equipment and Facilities	PPL Services Corporation	see footnote	322,126
37				
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, 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.: 4 Column: c
Accounts charged include: 163, 184, 426.4, 426.5, 500-502, 506, 510, 512, 513, 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.: 5 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.: 6 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.: 7 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.: 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, 186, 232, 408.1, 426.4, 426.5, 500-502, 506, 510, 512, 513, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592-594, 598, 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, 186, 426.4, 426.5, 500-502, 506, 510-513, 549, 556, 560-563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 590, 592, 901-903, 905, 907, 908, 921, 923, 925, 930.2, 931 and 935

Schedule Page: 429 Line No.: 13 Column: c
Accounts charged include: 184, 408.2, 426.4, 426.5, 500-502, 506, 510, 512-514, 549, 556, 560-563, 566, 570, 571, 573, 580, 581, 583, 586, 588, 590, 592, 593, 598, 901-903, 905, 907, 908, 910, 920, 921, 924, 928, 930.2 and 935

Schedule Page: 429 Line No.: 14 Column: c
Accounts charged include: 163, 184, 426.5, 500-502, 506, 510-514, 560, 561.1, 561.5, 566, 570, 573, 580, 583, 586, 588, 593, 598, 901, 903, 907, 908, 921, 923, 930.2 and 935

Schedule Page: 429 Line No.: 15 Column: c
Accounts charged include: 163, 165, 184, 186, 188, 426.4, 426.5, 500-502, 506, 510, 511, 513, 514, 553, 556, 560, 561.1, 561.2, 561.5, 566, 570, 573, 580, 582, 583, 586, 588, 592, 593, 598, 901-903, 908, 910, 921, 923, 928, 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, 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.: 23 Column: c
Accounts charged include: 163, 184, 426.4, 426.5, 454, 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.: 24 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.: 25 Column: c

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FOOTNOTE DATA

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.: 26 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.: 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: 184, 408.1, 500, 560, 570, 580, 903, 920, 925, 926 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 and 921

Schedule Page: 429 Line No.: 33 Column: c

Accounts charged include: 184

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: 454

Schedule Page: 429 Line No.: 42 Column: a

Costs between Kentucky Utilities Company and Louisville Gas and Electric 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 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

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FOOTNOTE DATA

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 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

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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 ownership of a specific asset, asset ownership percentages are utilized to assign costs. The numerator 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 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.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2015/Q4

FOOTNOTE DATA

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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Kentucky Utilities Company
Case No. 2016-00370
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 shareholders or members during the period referenced. KU 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 KU 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 KU relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 16(7)(p), [Tab No. 46].

Kentucky Utilities Company
Case No. 2016-00370
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)

Kentucky Utilities Company
Case No. 2016-00370
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 - Kentucky Utilities Company

November 2015

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	125,338,463	150,307,948	(24,969,485)
Cost of Revenues	(44,109,194)	(62,447,888)	18,338,694
Electric Margin	81,229,269	87,860,060	(6,630,791)
O&M	(33,480,781)	(32,656,766)	(824,015)
Other Income & Expenses	(1,054,351)	(197,478)	(856,873)
Depreciation	(16,910,376)	(17,633,050)	722,673
Property tax	(2,272,976)	(2,345,179)	72,203
Equity in Earnings	0	0	0
Interest	(7,771,408)	(7,896,479)	125,071
Income Tax	(7,524,768)	(10,328,384)	2,803,616
Net Income Ongoing Operations	**12,214,610**	**16,802,724**	**(4,588,114)**
Special Items	0	0	0
Net Income	**12,214,610**	**16,802,724**	**(4,588,114)**

Net Income Continuing Operations - Kentucky Utilities Company

December 2015

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	135,525,762	174,425,442	(38,899,680)
Cost of Revenues	(47,051,864)	(72,885,776)	25,833,911
Electric Margin	88,473,898	101,539,666	(13,065,768)
O&M	(30,198,753)	(30,190,951)	(7,803)
Other Income & Expenses	(335,911)	(322,567)	(13,344)
Depreciation	(17,011,273)	(17,837,254)	825,982
Property tax	(2,241,703)	(2,345,179)	103,476
Equity in Earnings	0	0	0
Interest	(7,803,831)	(7,904,363)	100,532
Income Tax	(10,598,596)	(15,157,585)	4,558,989
Net Income Ongoing Operations	**20,283,831**	**27,781,767**	**(7,497,936)**
Special Items	0	0	0
Net Income	**20,283,831**	**27,781,767**	**(7,497,936)**

Net Income Continuing Operations - Kentucky Utilities Company

January 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	171,530,027	179,297,491	(7,767,464)
Cost of Revenues	(60,829,999)	(69,602,464)	8,772,465
Electric Margin	110,700,029	109,695,027	1,005,001
O&M	(27,530,373)	(28,694,182)	1,163,809
Other Income & Expenses	(561,903)	(698,387)	136,484
Depreciation	(17,121,427)	(17,527,992)	406,566
Property tax	(2,305,966)	(2,369,169)	63,203
Equity in Earnings	0	0	0
Interest	(7,881,977)	(8,113,715)	231,739
Income Tax	(21,357,221)	(20,118,030)	(1,239,191)
Net Income Ongoing Operations	**33,941,161**	**32,173,552**	**1,767,610**
Special Items	0	0	0
Net Income	**33,941,161**	**32,173,552**	**1,767,610**

Net Income Continuing Operations - Kentucky Utilities Company

February 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	150,262,481	165,061,945	(14,799,464)
Cost of Revenues	(51,062,830)	(63,362,292)	12,299,463
Electric Margin	99,199,652	101,699,653	(2,500,001)
O&M	(29,509,941)	(30,458,129)	948,188
Other Income & Expenses	(439,810)	(343,240)	(96,569)
Depreciation	(17,175,289)	(17,543,590)	368,301
Property tax	(2,408,023)	(2,369,169)	(38,854)
Equity in Earnings	0	0	0
Interest	(7,797,926)	(8,097,385)	299,459
Income Tax	(16,133,060)	(16,459,383)	326,323
Net Income Ongoing Operations	**25,735,603**	**26,428,757**	**(693,154)**
Special Items	0	0	0
Net Income	**25,735,603**	**26,428,757**	**(693,154)**

Net Income Continuing Operations - Kentucky Utilities Company

March 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	130,750,389	155,243,710	(24,493,321)
Cost of Revenues	(44,690,151)	(59,549,489)	14,859,338
Electric Margin	86,060,238	95,694,221	(9,633,983)
O&M	(34,831,847)	(35,787,066)	955,220
Other Income & Expenses	(34,589)	(387,556)	352,966
Depreciation	(17,193,391)	(17,563,857)	370,466
Property tax	(2,368,959)	(2,369,169)	210
Equity in Earnings	0	0	0
Interest	(7,830,293)	(8,097,969)	267,676
Income Tax	(8,477,637)	(11,815,877)	3,338,240
Net Income Ongoing Operations	**15,323,523**	**19,672,728**	**(4,349,205)**
Special Items	0	0	0
Net Income	**15,323,523**	**19,672,728**	**(4,349,205)**

Net Income Continuing Operations - Kentucky Utilities Company

April 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	127,077,606	138,791,362	(11,713,757)
Cost of Revenues	(43,849,520)	(51,988,980)	8,139,460
Electric Margin	83,228,086	86,802,382	(3,574,296)
O&M	(36,096,348)	(32,991,018)	(3,105,330)
Other Income & Expenses	(336,949)	(461,585)	124,636
Depreciation	(17,191,030)	(17,592,798)	401,768
Property tax	(2,369,700)	(2,369,169)	(531)
Equity in Earnings	0	0	0
Interest	(7,841,877)	(8,119,279)	277,402
Income Tax	(7,389,709)	(9,604,258)	2,214,549
Net Income Ongoing Operations	**12,002,473**	**15,664,275**	**(3,661,802)**
Special Items	0	0	0
Net Income	**12,002,473**	**15,664,275**	**(3,661,802)**

Net Income Continuing Operations - Kentucky Utilities Company

May 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	128,722,907	143,519,179	(14,796,272)
Cost of Revenues	(45,245,716)	(57,129,211)	11,883,495
Electric Margin	83,477,191	86,389,968	(2,912,777)
O&M	(28,282,590)	(30,545,783)	2,263,193
Other Income & Expenses	(202,762)	(258,257)	55,495
Depreciation	(17,195,356)	(17,627,942)	432,586
Property tax	(2,251,944)	(2,369,169)	117,225
Equity in Earnings	0	0	0
Interest	(7,798,559)	(8,128,952)	330,393
Income Tax	(10,522,794)	(10,457,081)	(65,713)
Net Income Ongoing Operations	**17,223,188**	**17,002,785**	**220,403**
Special Items	0	0	0
Net Income	**17,223,188**	**17,002,785**	**220,403**

Net Income Continuing Operations - Kentucky Utilities Company

June 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	152,131,675	158,858,989	(6,727,315)
Cost of Revenues	(55,509,391)	(63,474,867)	7,965,476
Electric Margin	96,622,284	95,384,122	1,238,162
O&M	(27,442,238)	(31,609,879)	4,167,641
Other Income & Expenses	(178,142)	(338,882)	160,739
Depreciation	(17,239,404)	(17,664,901)	425,497
Property tax	(2,343,375)	(2,369,169)	25,794
Equity in Earnings	0	0	0
Interest	(8,032,187)	(8,137,237)	105,050
Income Tax	(15,768,979)	(13,281,898)	(2,487,080)
Net Income Ongoing Operations	**25,617,958**	**21,982,155**	**3,635,803**
Special Items	0	0	0
Net Income	**25,617,958**	**21,982,155**	**3,635,803**

Net Income Continuing Operations - Kentucky Utilities Company

July 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	162,645,678	171,187,277	(8,541,599)
Cost of Revenues	(60,945,796)	(67,636,901)	6,691,105
Electric Margin	101,699,882	103,550,377	(1,850,494)
O&M	(28,598,418)	(30,200,815)	1,602,397
Other Income & Expenses	(358,839)	(203,053)	(155,787)
Depreciation	(17,281,078)	(17,705,376)	424,298
Property tax	(2,392,853)	(2,374,131)	(18,722)
Equity in Earnings	0	0	0
Interest	(7,978,341)	(8,122,753)	144,412
Income Tax	(17,386,297)	(17,255,539)	(130,758)
Net Income Ongoing Operations	**27,704,055**	**27,688,710**	**15,345**
Special Items	0	0	0
Net Income	**27,704,055**	**27,688,710**	**15,345**

Net Income Continuing Operations - Kentucky Utilities Company

August 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	165,481,768	175,521,187	(10,039,419)
Cost of Revenues	(60,407,949)	(69,175,575)	8,767,625
Electric Margin	105,073,818	106,345,612	(1,271,794)
O&M	(30,288,136)	(32,106,805)	1,818,669
Other Income & Expenses	146,889	(216,844)	363,733
Depreciation	(17,335,800)	(17,742,460)	406,660
Property tax	(2,403,656)	(2,374,131)	(29,525)
Equity in Earnings	0	0	0
Interest	(8,041,853)	(8,095,289)	53,436
Income Tax	(18,262,202)	(17,594,110)	(668,092)
Net Income Ongoing Operations	**28,889,061**	**28,215,973**	**673,088**
Special Items	0	0	0
Net Income	**28,889,061**	**28,215,973**	**673,088**

Net Income Continuing Operations - Kentucky Utilities Company

September 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	145,277,018	150,886,835	(5,609,816)
Cost of Revenues	(53,750,535)	(56,056,612)	2,306,077
Electric Margin	91,526,483	94,830,223	(3,303,739)
O&M	(27,923,159)	(32,773,722)	4,850,563
Other Income & Expenses	(1,368,014)	(245,041)	(1,122,973)
Depreciation	(17,283,073)	(17,777,549)	494,476
Property tax	(2,360,459)	(2,374,131)	13,672
Equity in Earnings	0	0	0
Interest	(8,394,440)	(8,199,799)	(194,641)
Income Tax	(12,741,414)	(12,577,342)	(164,071)
Net Income Ongoing Operations	**21,455,925**	**20,882,638**	**573,287**
Special Items	0	0	0
Net Income	**21,455,925**	**20,882,638**	**573,287**

Net Income Continuing Operations - Kentucky Utilities Company

October 2016

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	130,325,252	142,080,292	(11,755,040)
Cost of Revenues	(48,861,239)	(55,108,183)	6,246,944
Electric Margin	81,464,013	86,972,109	(5,508,096)
O&M	(29,867,433)	(33,622,175)	3,754,743
Other Income & Expenses	(205,801)	(282,764)	76,962
Depreciation	(17,323,988)	(17,809,320)	485,332
Property tax	(2,410,385)	(2,374,131)	(36,254)
Equity in Earnings	0	0	0
Interest	(8,008,360)	(8,116,155)	107,795
Income Tax	(9,246,457)	(9,405,301)	158,844
Net Income Ongoing Operations	**14,401,588**	**15,362,262**	**(960,674)**
Special Items	0	0	0
Net Income	**14,401,588**	**15,362,262**	**(960,674)**

Kentucky Utilities Company
Case No. 2016-00370
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.

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				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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	MTD Budget	MTD 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	YTD Budget	YTD 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	Full Year Budget	Full Year 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.

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Financing Activities							**March 2015**
($ Millions)							
	MTD				**YTD**		
Balance Sheet	**Actual**	**Budget**	**Variance**		**Actual**	**Budget**	**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	**YTD**	
($ Millions)	**Actual**	**+/- 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.

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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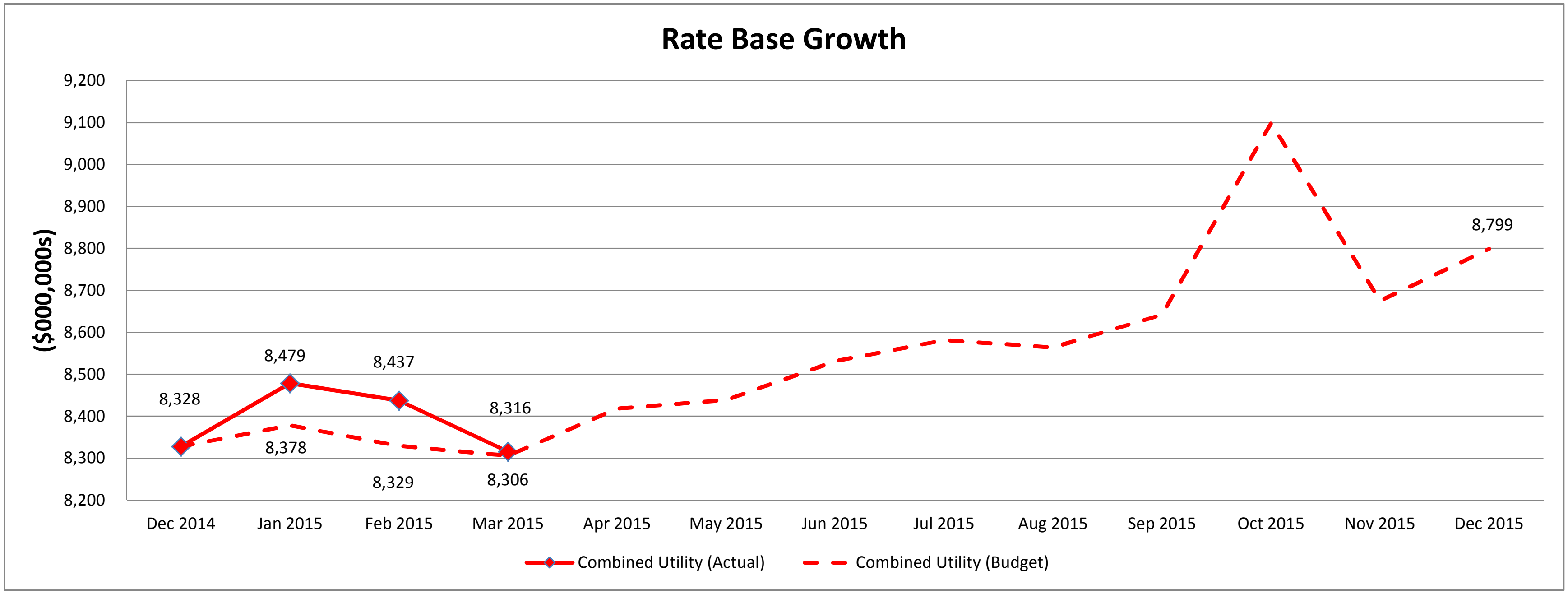
Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,328
8,479
8,437
8,316
8,378
8,329
8,306
8,799
Dec 2014
Jan 2015
Feb 2015
Mar 2015
Apr 2015
May 2015
Jun 2015
Jul 2015
Aug 2015
Sep 2015
Oct 2015
Nov 2015
Dec 2015
Combined Utility (Actual)
Combined Utility (Budget)

Combined 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 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:						$ (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 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	$ 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 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	$ 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):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD 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 Act	MTD +/- Bud		YTD Act	YTD +/- 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				YTD			
	Actual	**Budget**	**Subtotal**	**Margin Variance**	**Actual**	**Budget**	**Subtotal**	**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			Budget			Variance		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**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			Budget			Variance		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**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

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

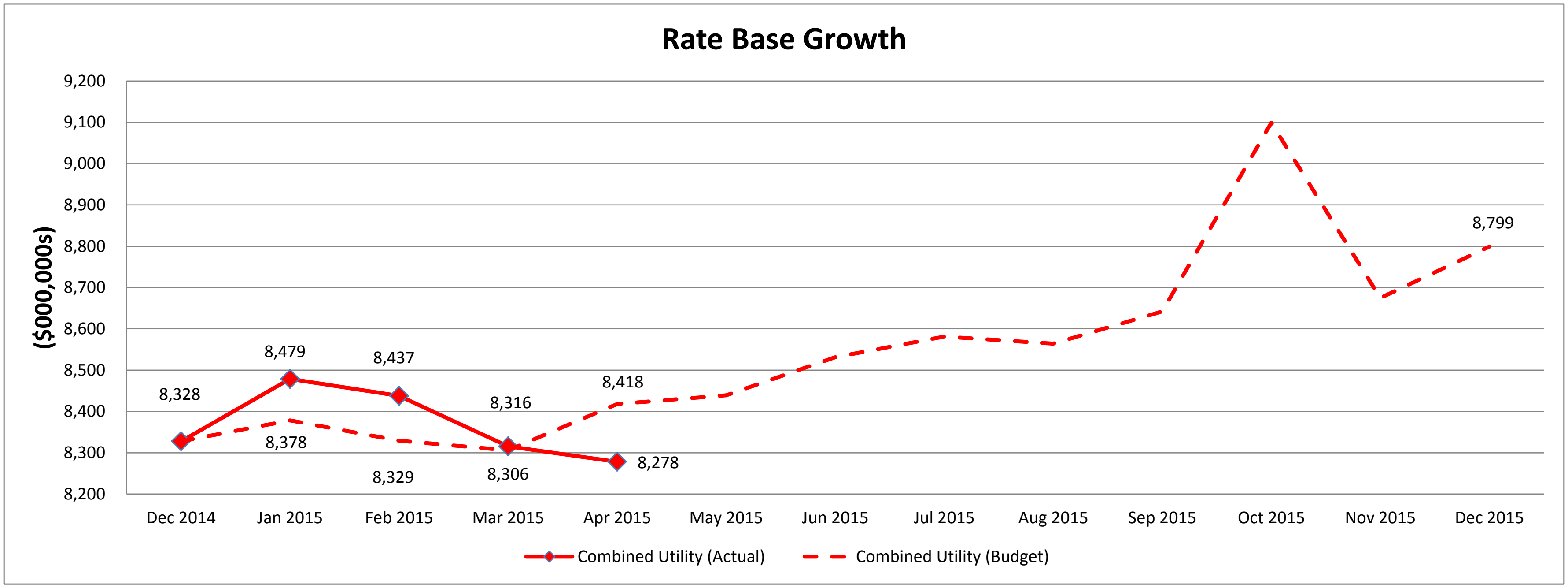
(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

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.


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
8,418
8,378
8,329
8,306
8,278
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)

Performance Report

May 2015

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Kentucky Regulated Dashboard

May 2015

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**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	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**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%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**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)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**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)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**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	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,498	3,567	3,498	3,567	3,543	3,566

Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**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	MTD Budget	MTD 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	Budget	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						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	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			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	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			YTD		
	Act	+/- Bud		Act	+/- 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				YTD			
	Actual	**Budget**	**Subtotal**	**Margin Variance**	**Actual**	**Budget**	**Subtotal**	**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			Budget			Variance		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**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			Budget			Variance		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**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.

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

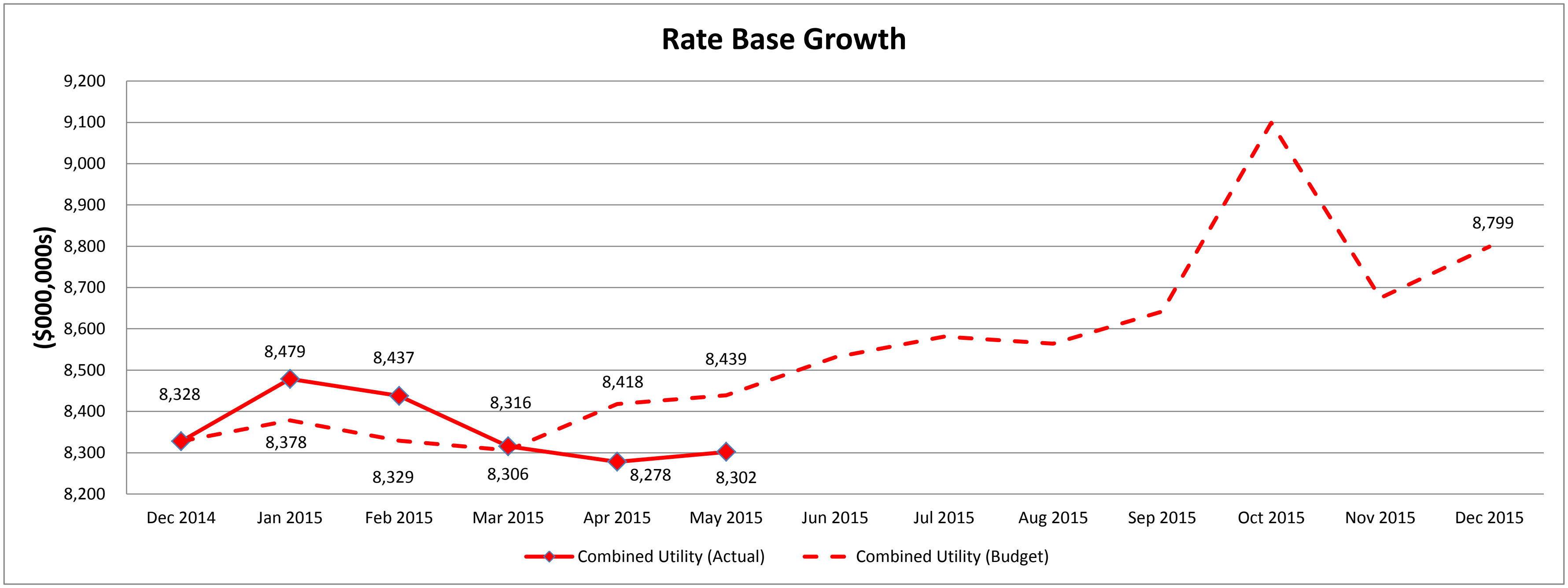
Balance Sheet

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.

Income Statement: Actual vs. Budget and Forecast (Month) — June 2015

($ Millions)

	MTD Actual	MTD Budget	MTD Variance	Comments	MTD Actual	Q1 Forecast	MTD 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.

Gas Gross Margin

June 2015

($ Millions)

	MTD				YTD			
	Actual	**Budget**	**Subtotal**	**Margin Variance**	**Actual**	**Budget**	**Subtotal**	**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			**Budget**			**Variance**		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**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			**Budget**			**Variance**		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**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

O&M	June 2015

($ 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.

($ 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

Balance Sheet — June 2015

($ Millions)

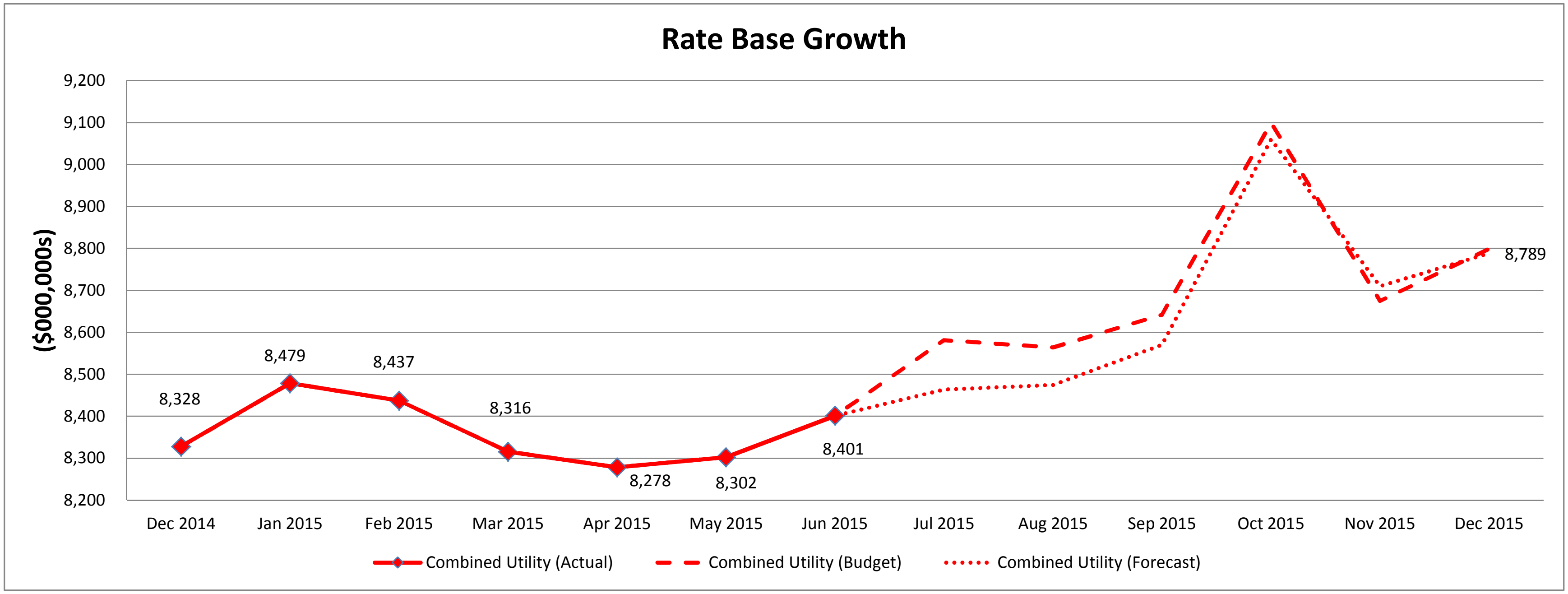
	6/30/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 16	$ (2)	
Accounts Receivable (Trade)	378	418	(40)	Lower customer accounts receivable ($29m) and accrued utility revenue ($12m).
Inventory	249	256	(6)	
Deferred Income Taxes	42	16	26	Due to NOL utilization 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.

Cash Flow

June 2015

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)**	



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
8,789
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)

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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

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 Actual	MTD Budget	MTD Variance	Comments	MTD Actual	Q2 Forecast	MTD 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 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	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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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Blake

Gas Gross Margin — July 2015

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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.

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

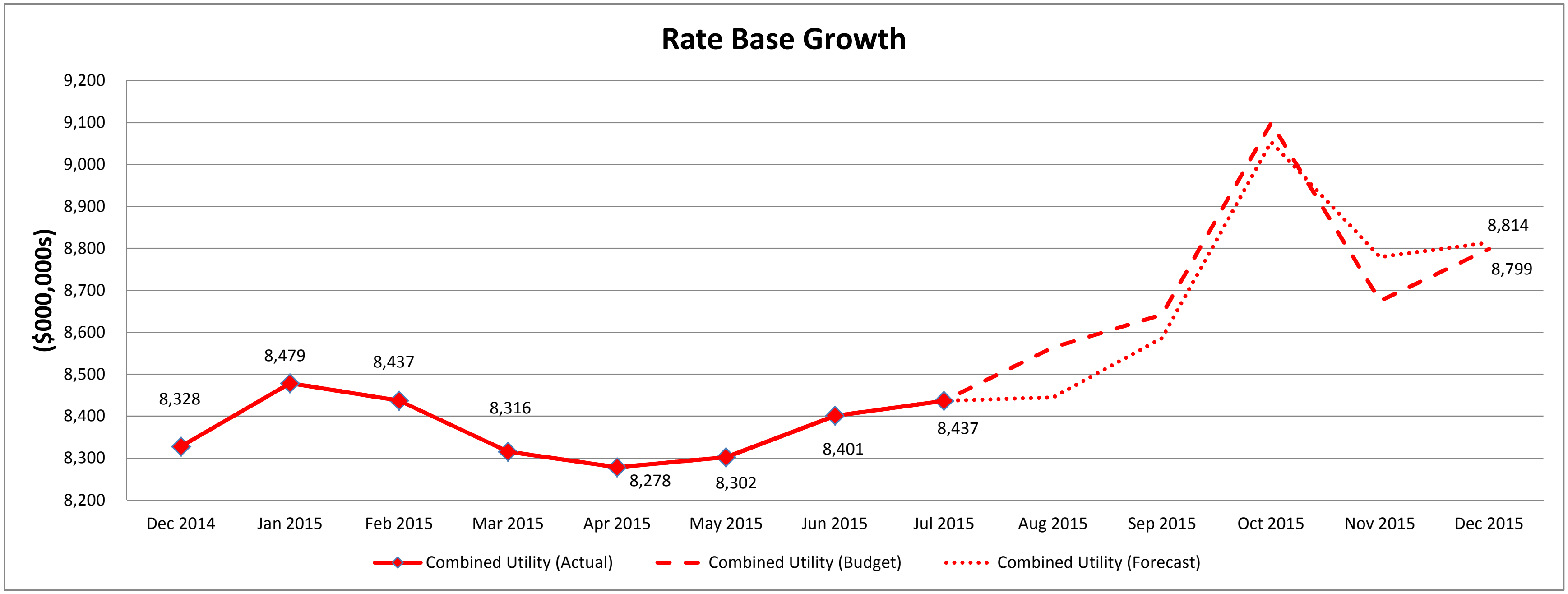
Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	36.3%	3%	27.2%	-5%
FFO to Debt - KU	29.3%	4%	23.8%	1%
Debt to EBITDA - LG&E (2)	3.32	-0.17	3.56	-0.02
Debt to EBITDA - KU (2)	3.61	-0.23	3.56	-0.14
Debt to Capitalization - LG&E (3)	46.6%	0%	47.0%	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.


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.

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.

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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.

Gas Gross Margin — August 2015

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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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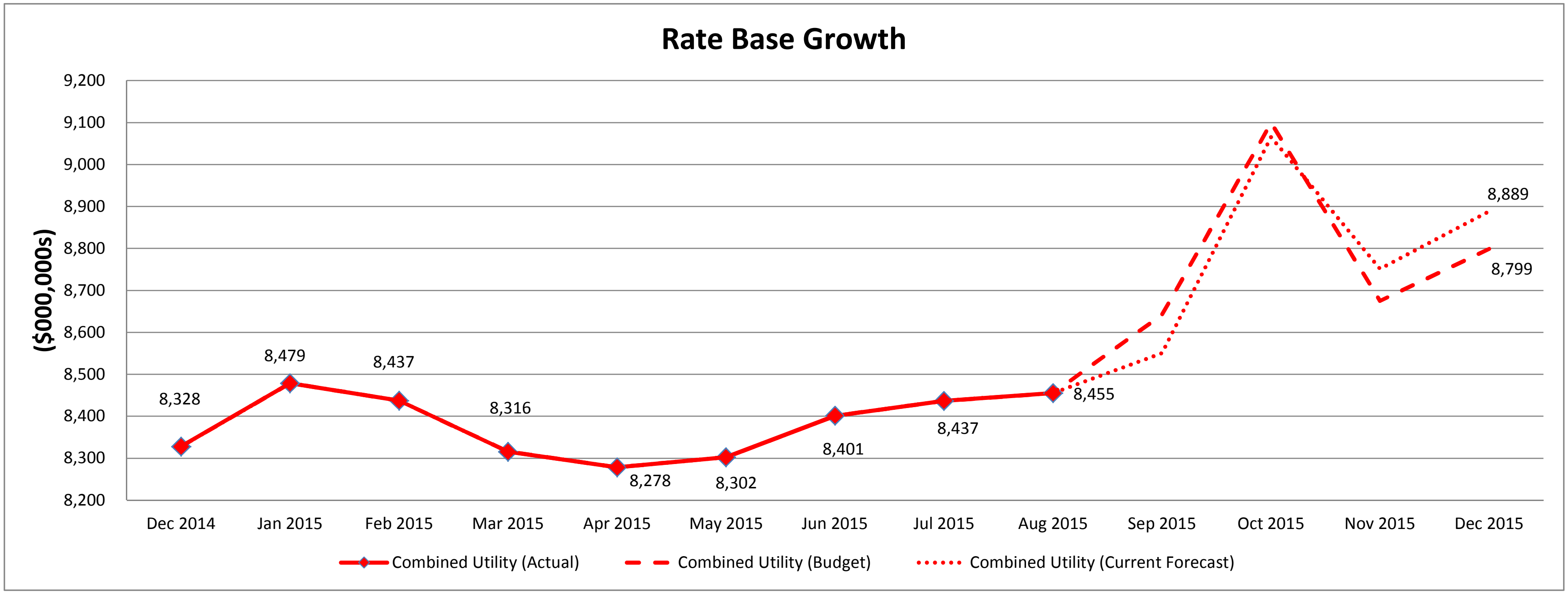

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Performance Report

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.

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Income Statement: Actual vs. Budget (YTD) — September 2015

($ Millions)

	YTD Actual	YTD Budget	YTD 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.

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Income Statement: Forecast vs. Prior Forecast & Budget — September 2015

($ Millions)

	Full Year Q3 Forecast	Full Year Q2 Forecast	Full Year Variance	Comments	Full Year Q3 Forecast	Full Year Budget	Full Year 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						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	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			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	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 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	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 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	$ 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.

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

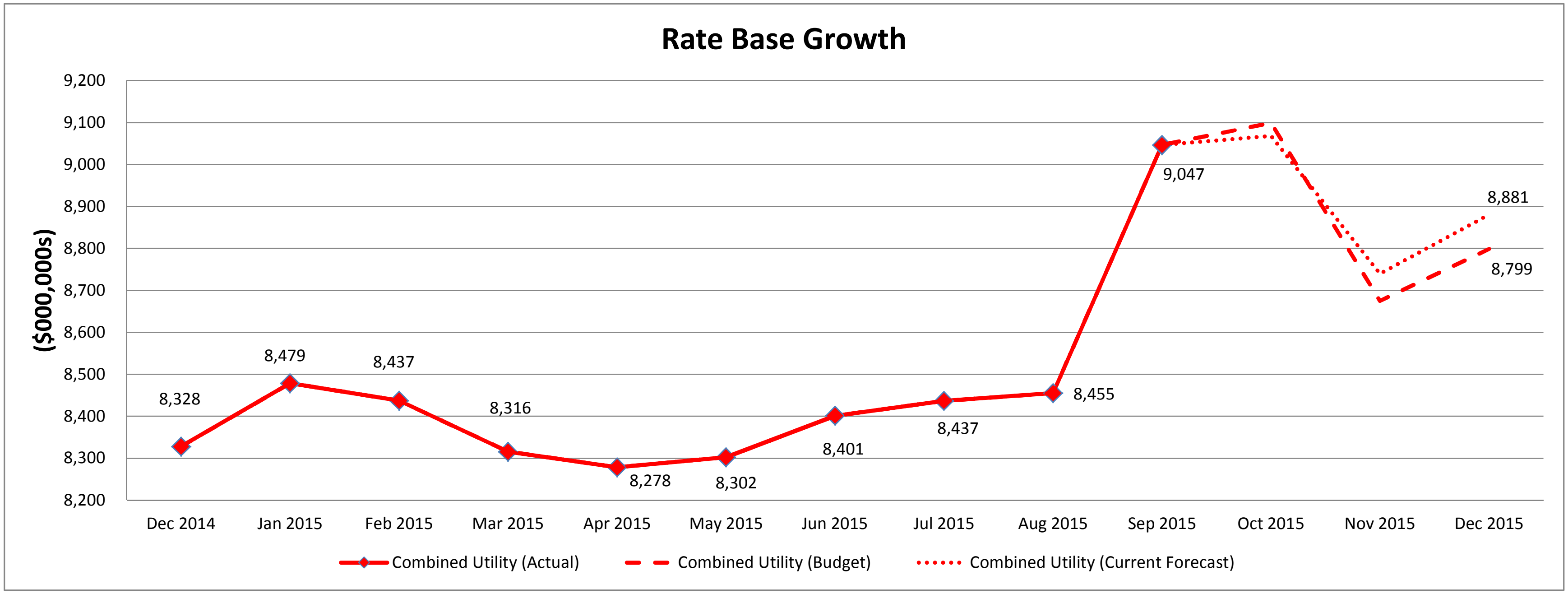
Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	28.1%	-5%	25.8%	-7%
FFO to Debt - KU	24.0%	-1%	22.6%	-1%
Debt to EBITDA - LG&E [(2)]	3.29	-0.20	3.60	0.02
Debt to EBITDA - KU [(2)]	3.52	-0.32	3.62	-0.08
Debt to Capitalization - LG&E [(3)]	50.5%	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)

Cash Flow

September 2015

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**	

Combined KU and LG&E ROE — September 2015

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**				**MTD**				
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q3 Forecast**	**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.

Income Statement: Actual vs. Budget (YTD) — October 2015

($ Millions)

	YTD			
	Actual	Budget	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 Q3 Forecast	Full Year Q2 Forecast	Variance	Comments	Full Year 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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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

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O&M									October 2015

($ 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.

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

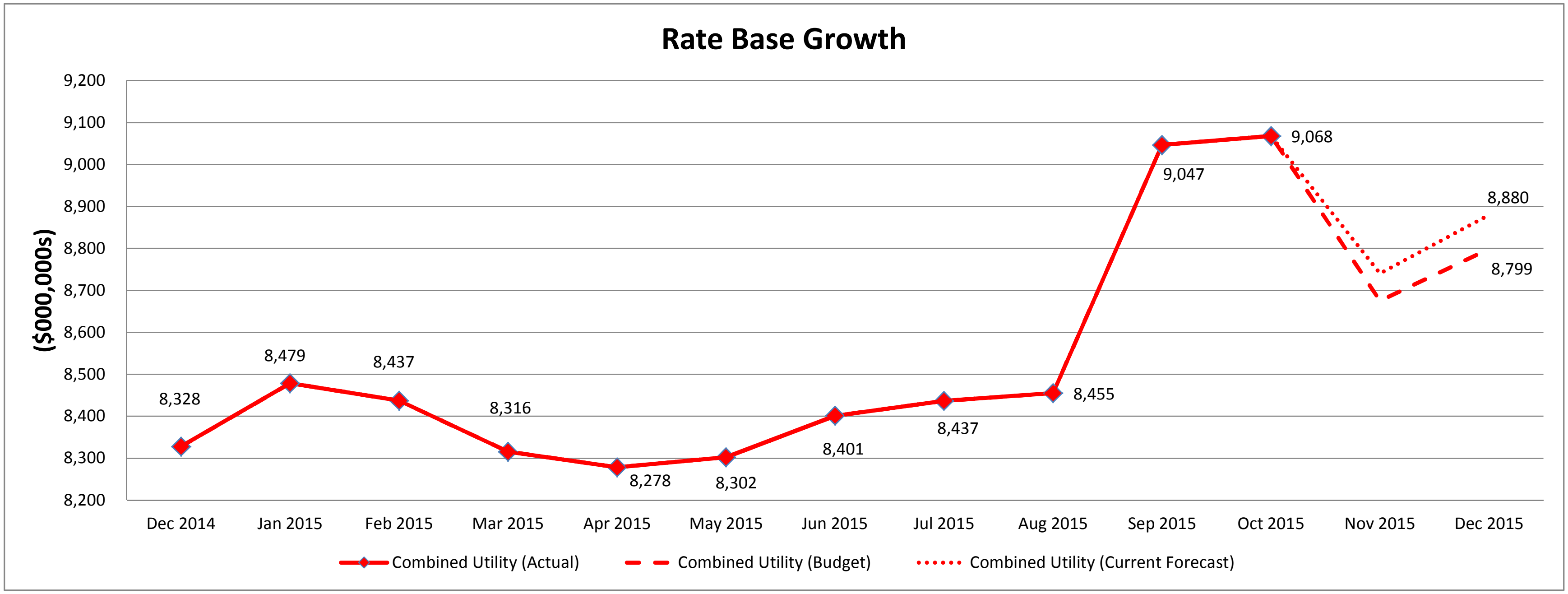
(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

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.


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
8,880
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

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				MTD			
	Actual	Budget	Variance	Comments	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.

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.

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

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O&M	November 2015

($ Millions)

	MTD								
	Actual	Budget	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	Budget	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	Budget	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.

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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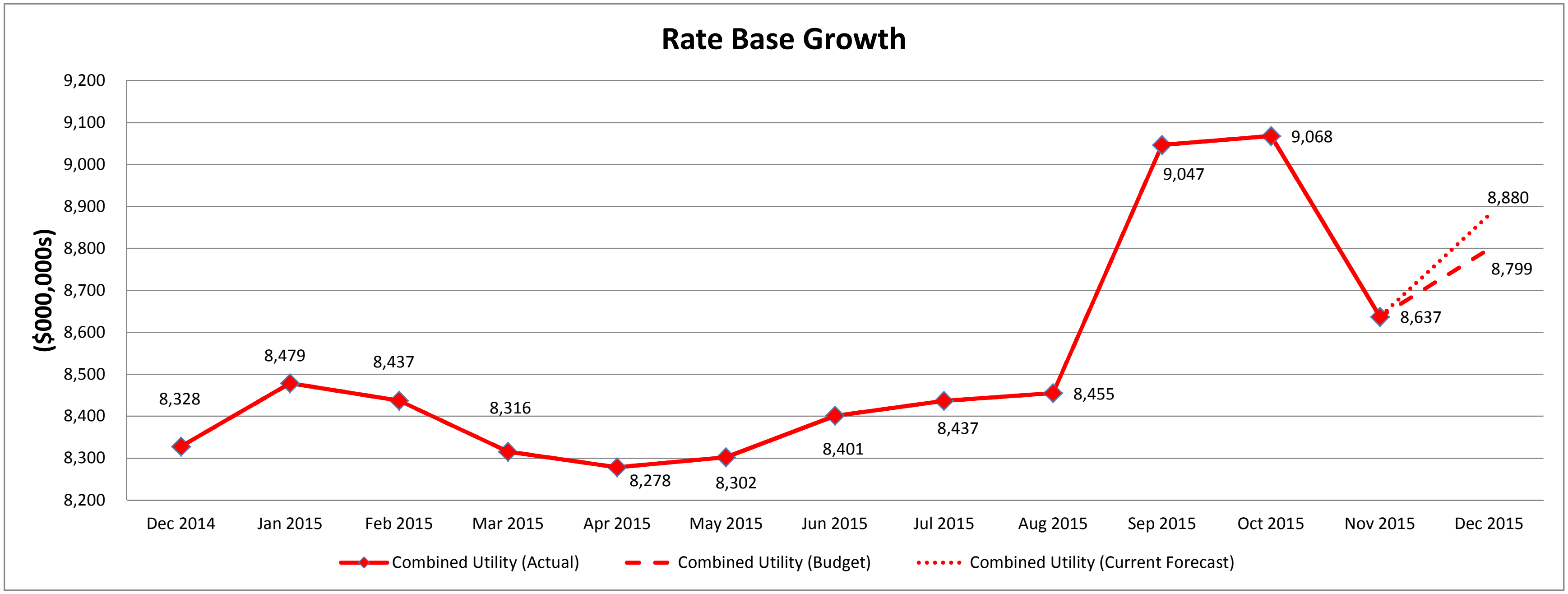

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Performance Report

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	Budget	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

($ 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)

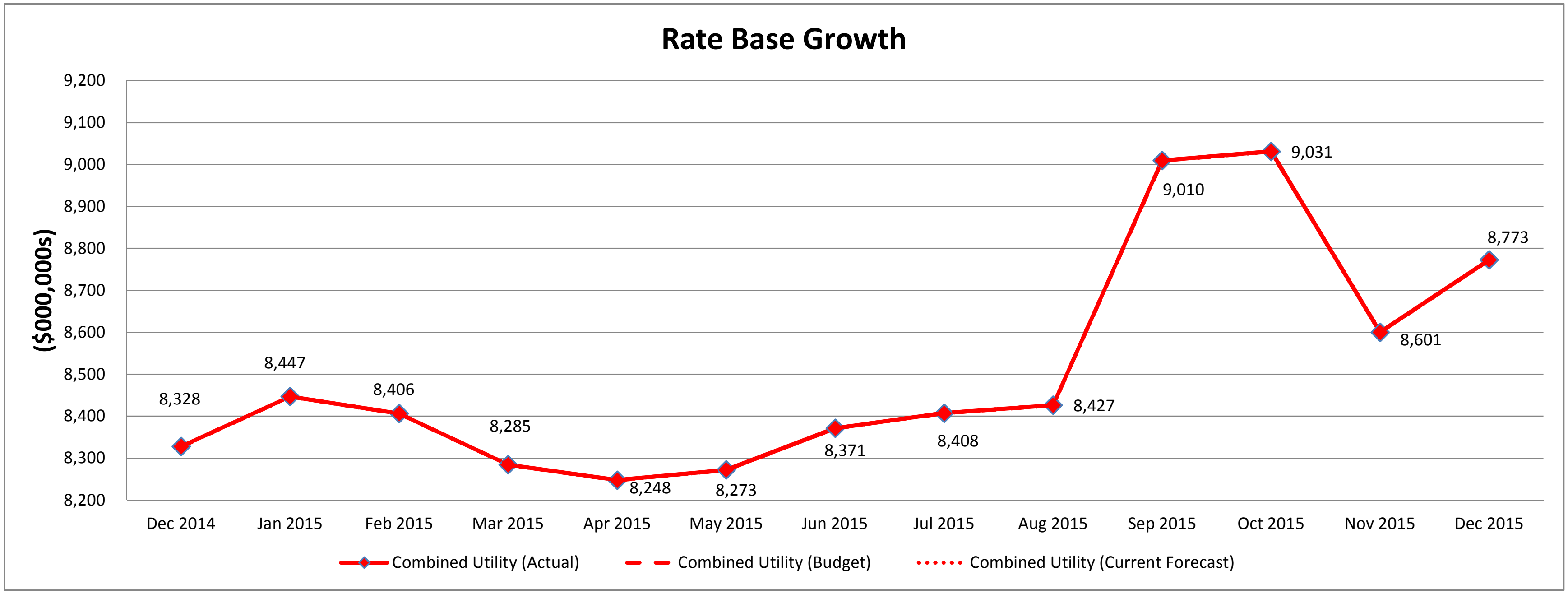
	12/31/2015	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 30	$ 17	$ 13	Primarily due to lower dividend payments and increased borrowing than assumed in budget.
Accounts Receivable (Trade)	362	417	(55)	Lower customer accounts receivable ($36m) and accrued utility 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.

Cash Flow

December 2015

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**	



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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.

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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

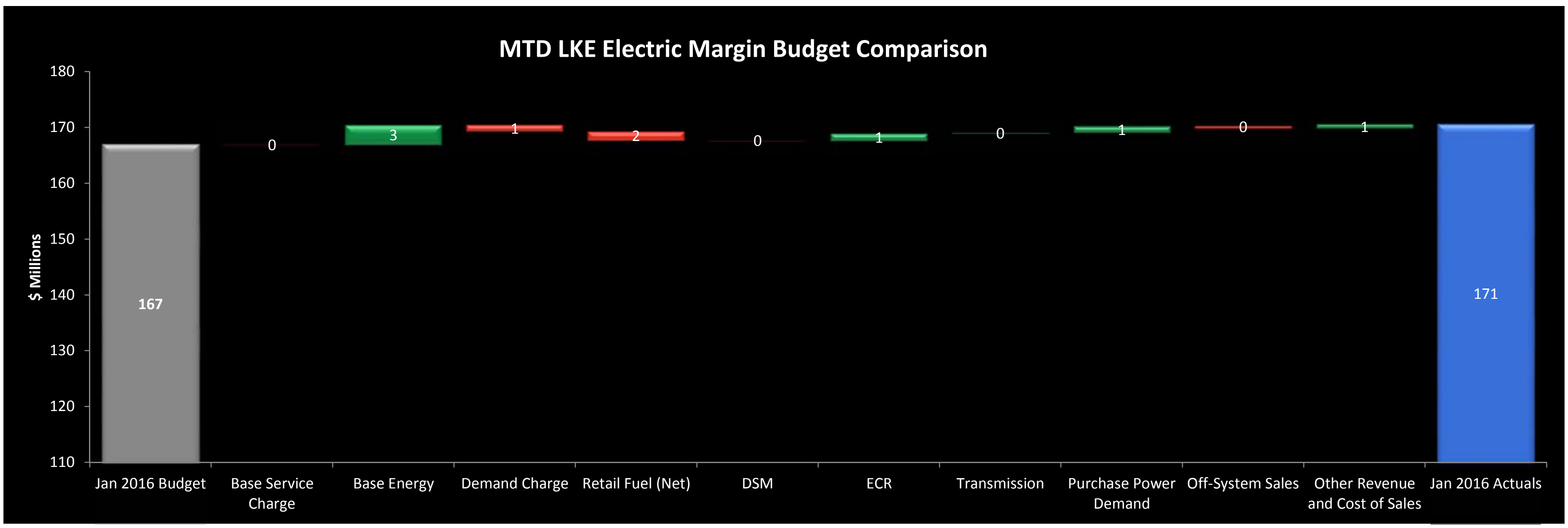
(In Thousands)	Volume	Price	Total Variance
Residential	4,619	537	5,157
Commercial	(41)	(885)	(926)
Industrial	(853)	197	(656)
Public Authority	(258)	126	(132)
Street Lights	(101)	421	320
Municipals	17	(343)	(327)
Other	-	-	-
	$ 3,382	$ 53	$ 3,436

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)

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O&M

January 2016

($ 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

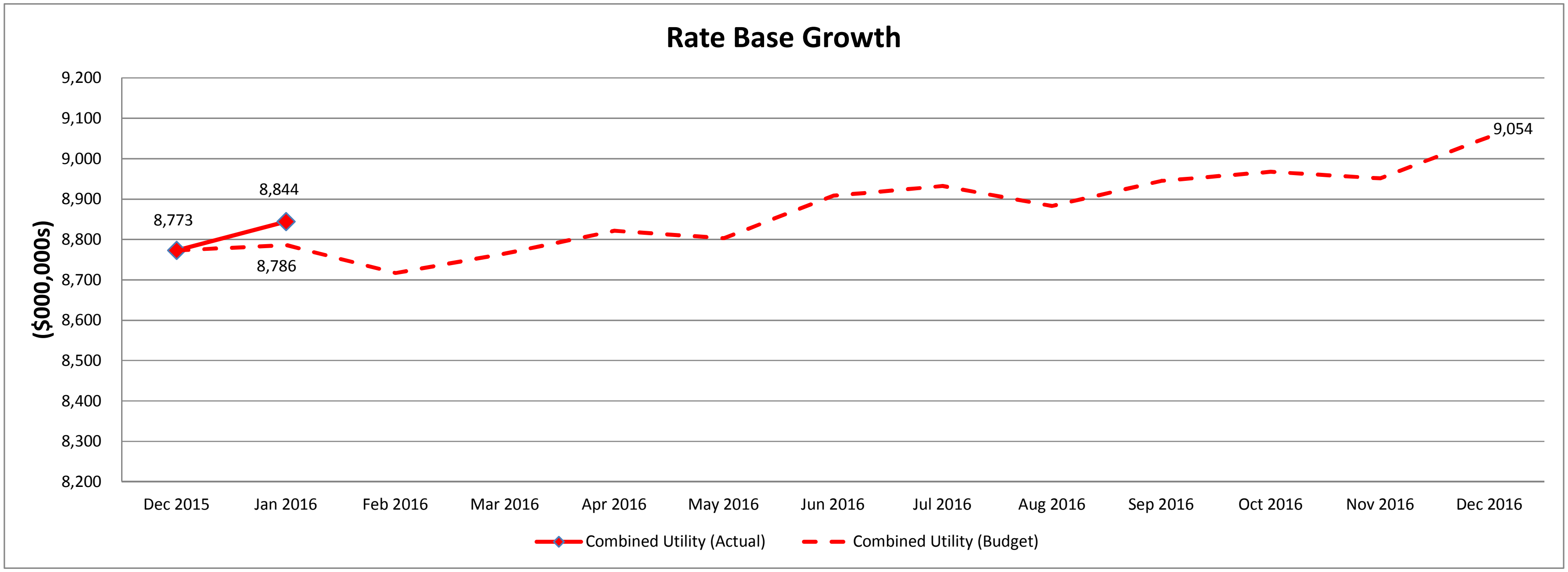
January 2016

($ 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.


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
8,786
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	MTD Budget	MTD 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	YTD Budget	YTD 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.

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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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

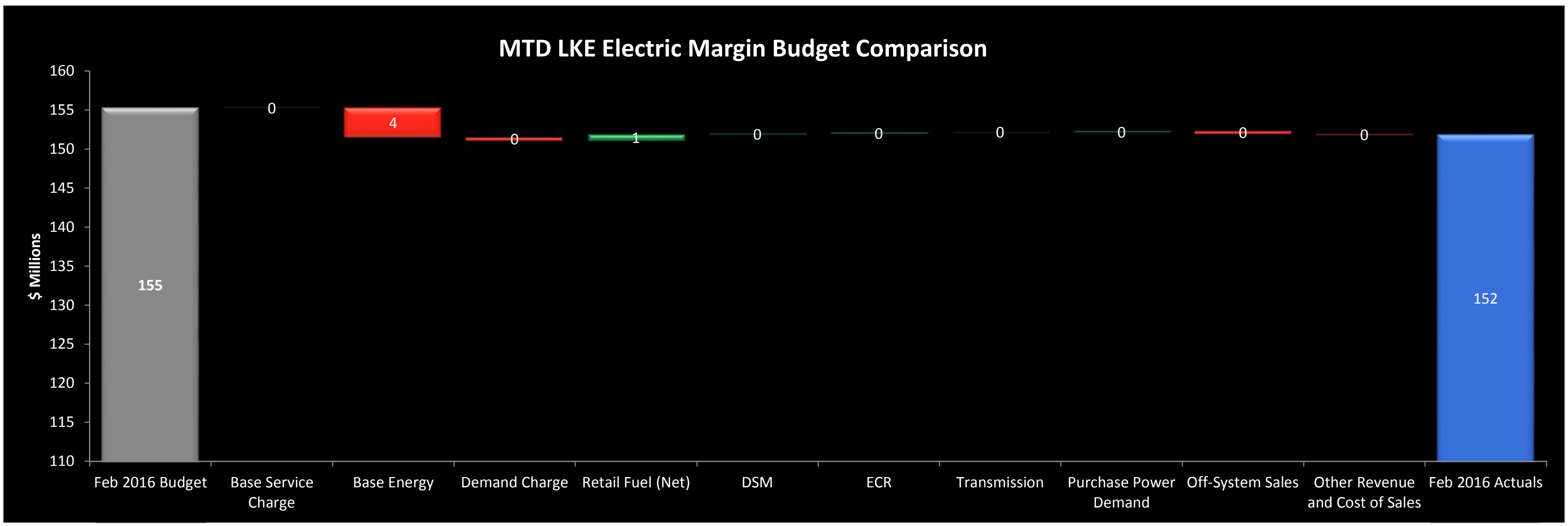
(In Thousands)	Volume	Price	Total Variance
Residential	(4,406)	420	(3,986)
Commercial	662	(498)	165
Industrial	138	107	244
Public Authority	170	147	316
Street Lights	(66)	(197)	(262)
Municipals	(12)	(228)	(240)
Other	-	-	-
	$ (3,514)	$ (248)	$ (3,762)

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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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

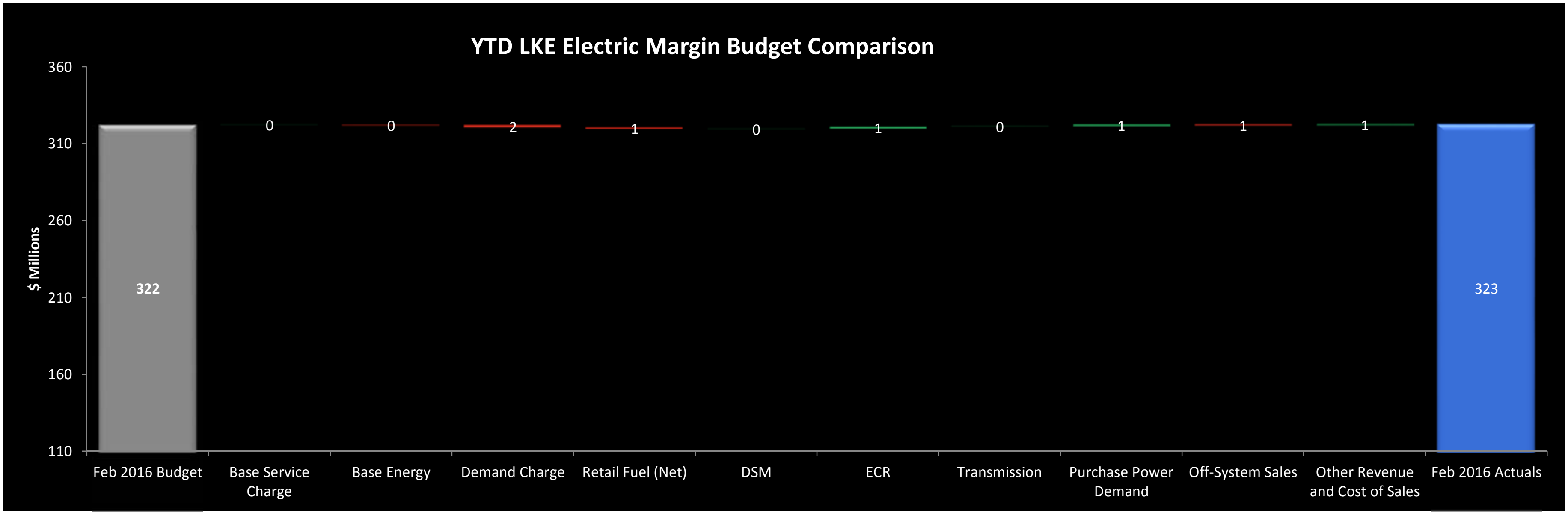
(In Thousands)	Volume	Price	Total Variance
Residential	225	946	1,171
Commercial	615	(1,377)	(762)
Industrial	(716)	305	(412)
Public Authority	(91)	275	184
Street Lights	(177)	235	58
Municipals	5	(571)	(567)
Other	-	-	-
	$ (139)	$ (187)	$ (327)

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				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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)

O&M								February 2016

($ 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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($ 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.

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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.

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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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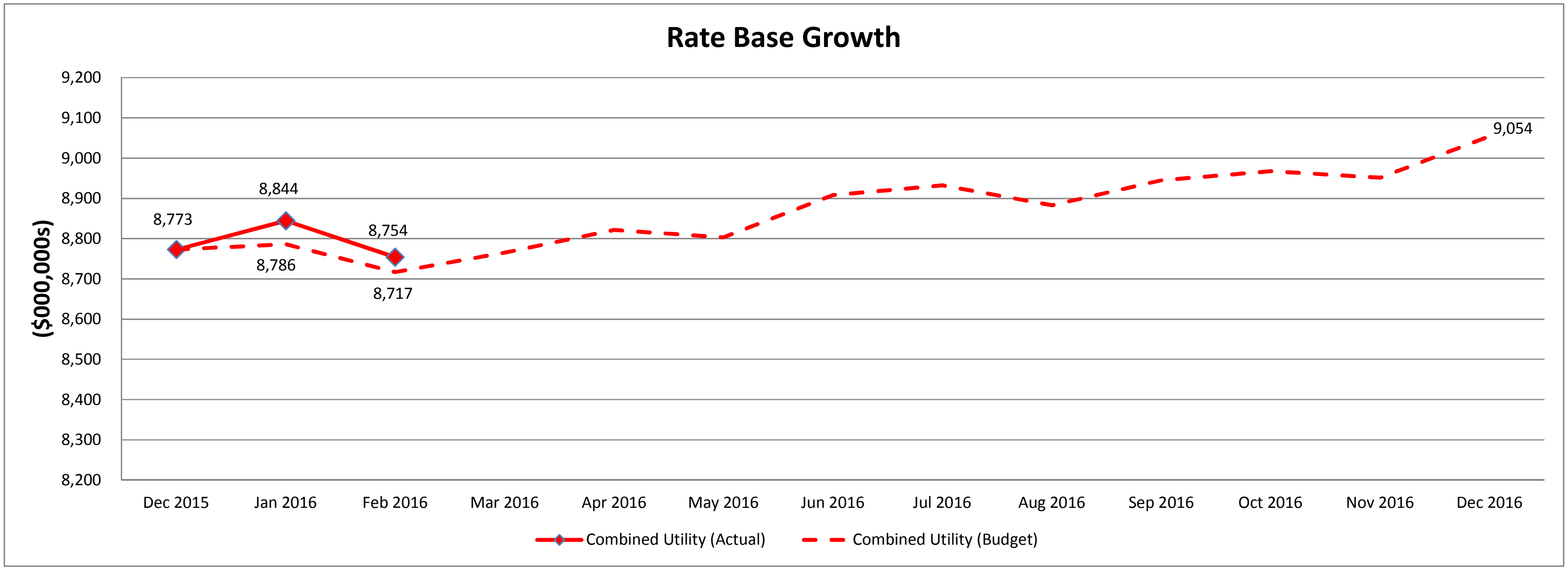
Rate Base Growth
($000,000s)
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,773
8,844
8,754
8,786
8,717
9,054
Dec 2015
Jan 2016
Feb 2016
Mar 2016
Apr 2016
May 2016
Jun 2016
Jul 2016
Aug 2016
Sep 2016
Oct 2016
Nov 2016
Dec 2016
Combined Utility (Actual)
Combined Utility (Budget)

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.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — March 2016

($ Millions)

	YTD Actual	YTD Budget	YTD 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.

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.

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

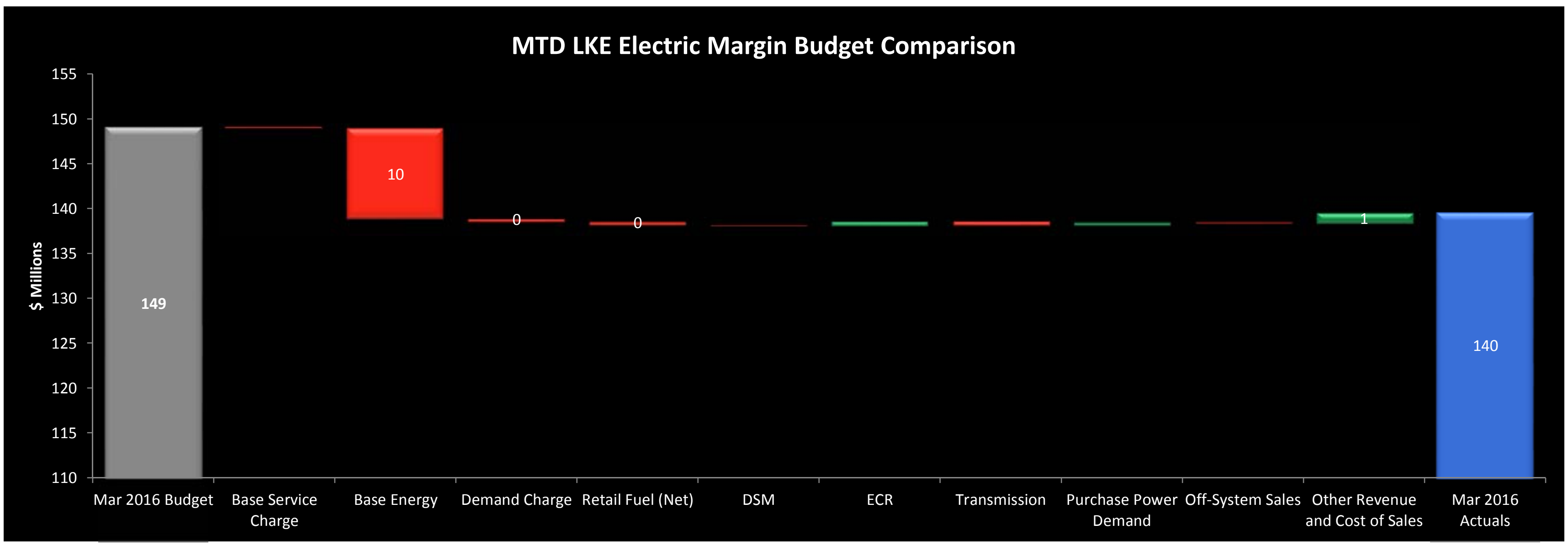
	Volume	Price	Total Variance
Residential	(9)	1	(9)
Commercial	(1)	(1)	(1)
Industrial	(0)	0	0
Public Authority	(0)	0	0
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	(10)	0	(10)

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

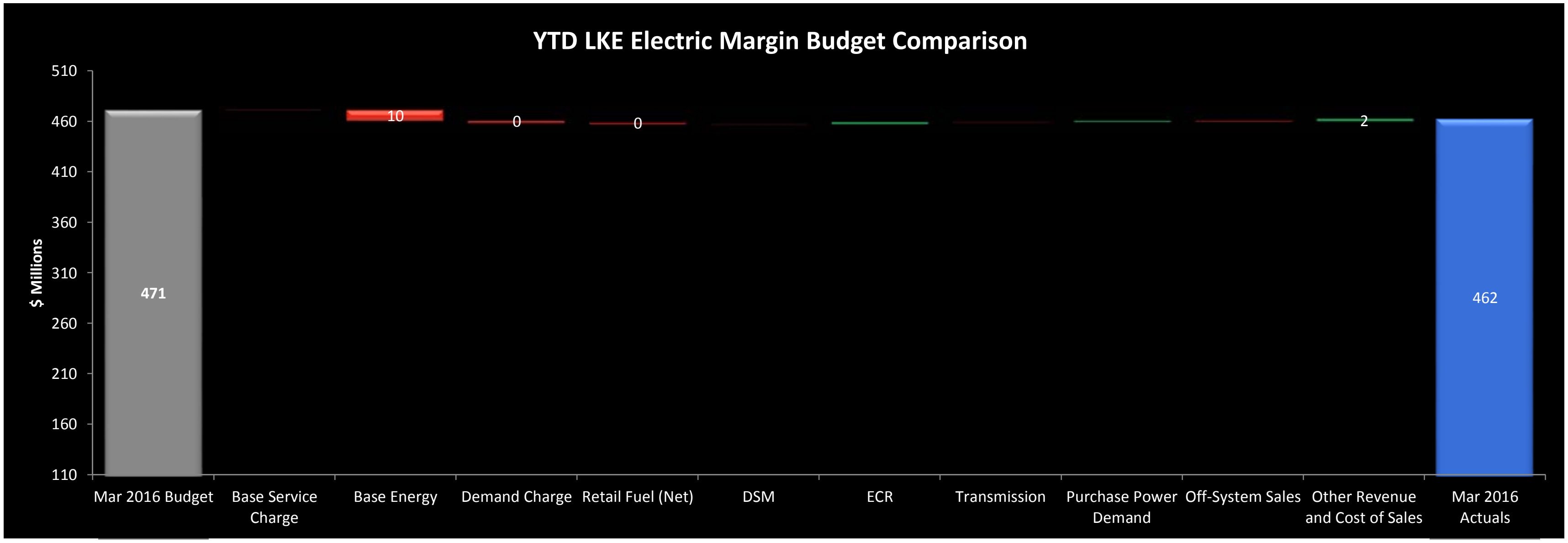
	Volume	Price	Total Variance
Residential	(9)	2	(8)
Commercial	0	(2)	(2)
Industrial	(1)	0	(0)
Public Authority	(0)	0	0
Street Lights	(0)	0	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(10)	0	(10)

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)

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O&M	March 2016

($ 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	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%	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	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 — 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.

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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.

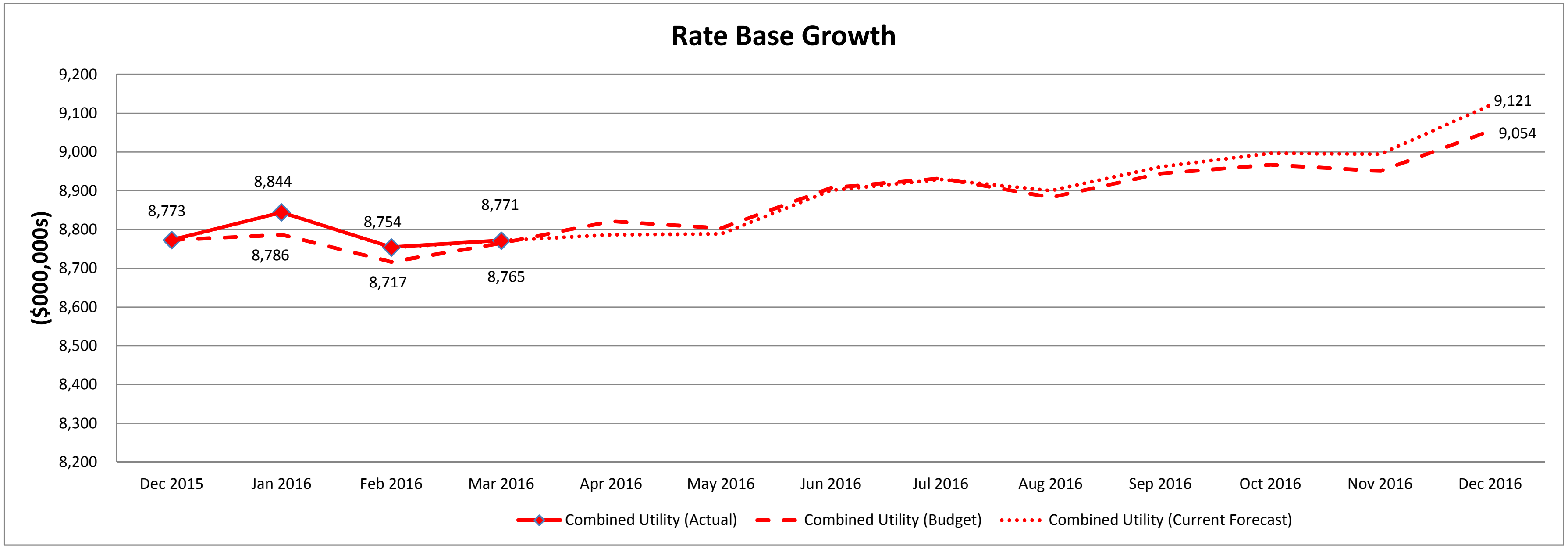
Balance Sheet - KU — March 2016

($ 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
8,773
8,844
8,754
8,771
8,786
8,717
8,765
9,121
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)

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.

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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.

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 **April 2016**
($ Millions)

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

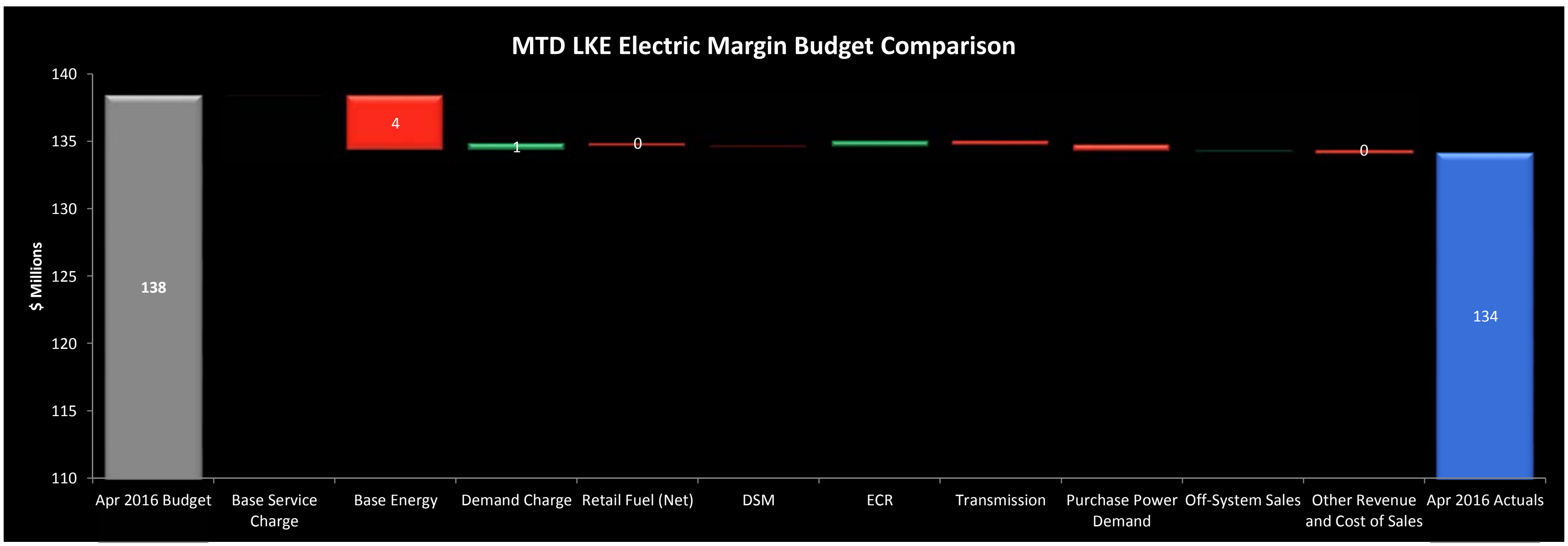
	Volume	Price	Total Variance
Residential	(4)	0	(4)
Commercial	1	(1)	(1)
Industrial	0	0	0
Public Authority	0	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	0	0
Other	0	0	0
	(3)	(1)	(4)

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

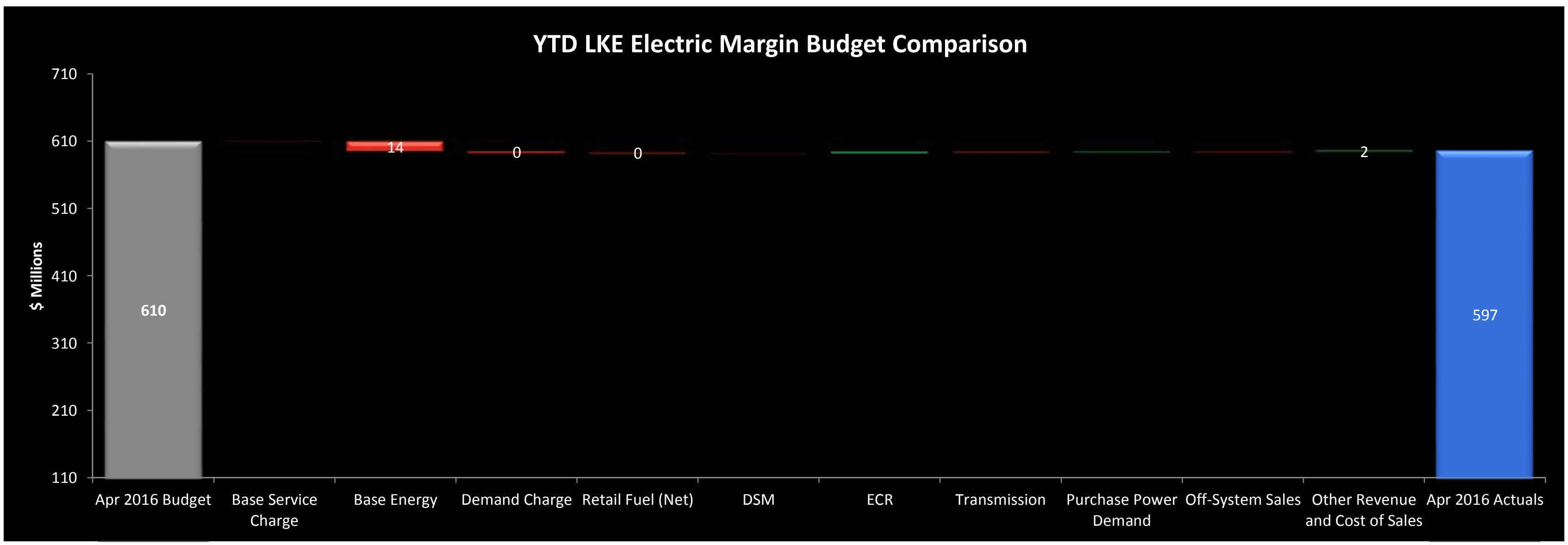
	Volume	Price	Total Variance
Residential	(13)	2	(11)
Commercial	1	(3)	(3)
Industrial	(1)	1	(0)
Public Authority	(0)	0	0
Street Lights	(1)	0	(0)
Municipals	(0)	(0)	(1)
Other	0	0	0
	(14)	(1)	(14)

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 Actual	MTD Budget	MTD Subtotal	MTD Margin Variance	YTD Actual	YTD Budget	YTD Subtotal	YTD 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 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	$ 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 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	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.

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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

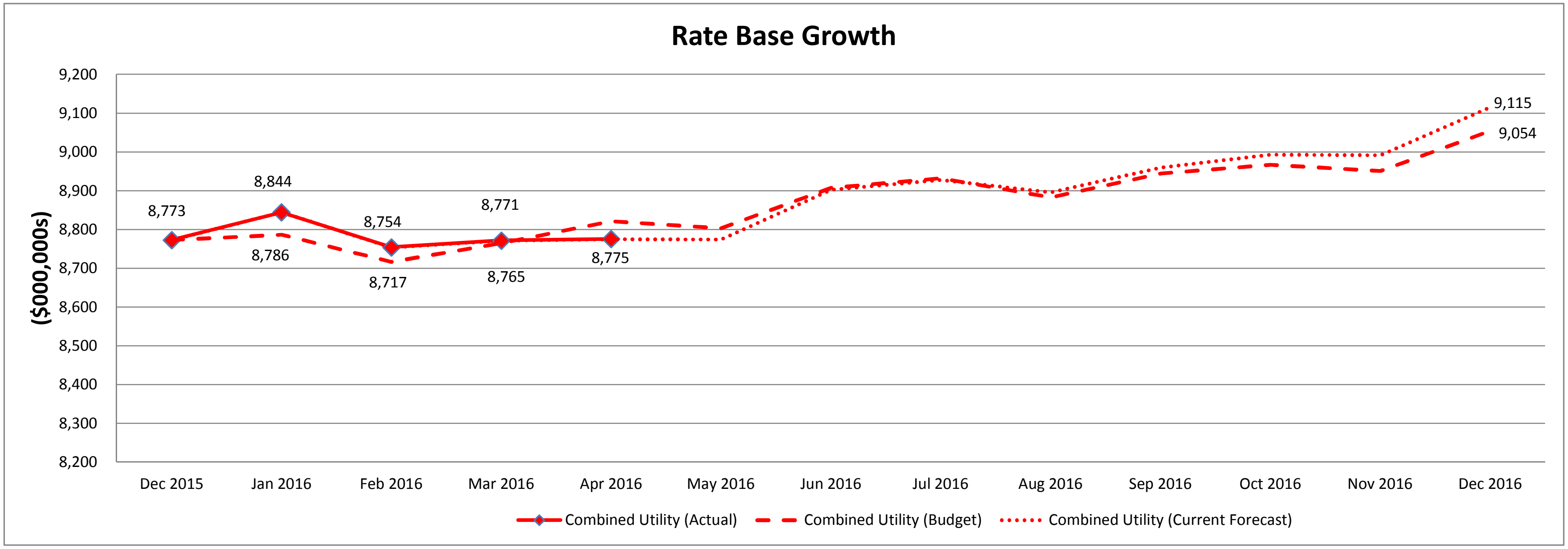
April 2016

($ 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.


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
8,775
8,786
8,717
8,765
9,115
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

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.

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
($ Millions)

May 2016

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

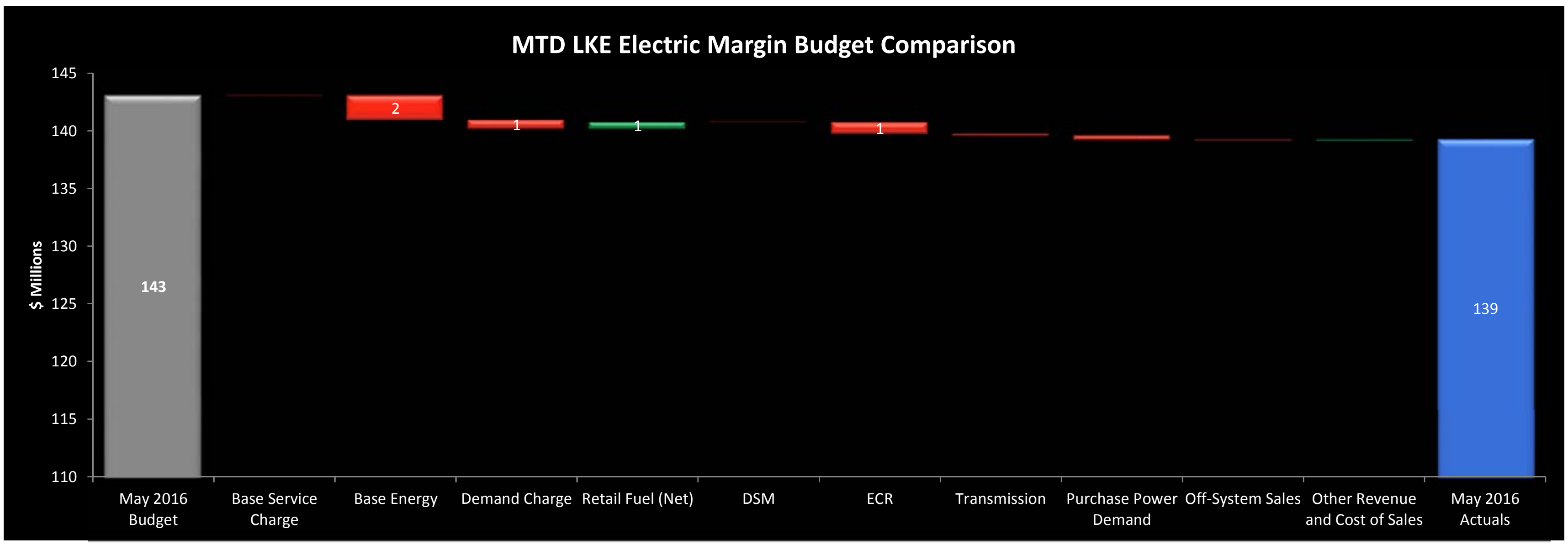
	Volume	Price	Total Variance
Residential	(0)	0	0
Commercial	(1)	(0)	(1)
Industrial	(1)	0	(1)
Public Authority	(0)	0	(0)
Street Lights	(0)	0	0
Municipals	(0)	(0)	(0)
Other	0	0	0
	(2)	0	(2)

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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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Blake

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

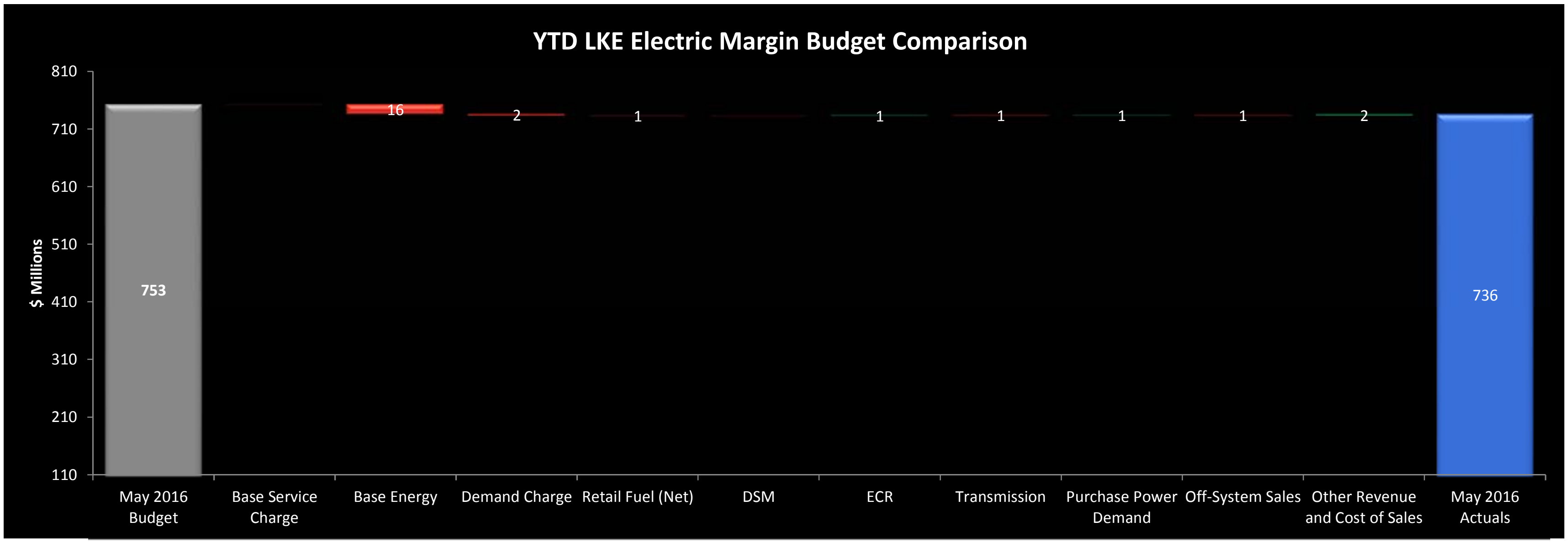
	Volume	Price	Total Variance
Residential	(13)	2	(11)
Commercial	(0)	(4)	(4)
Industrial	(2)	1	(1)
Public Authority	(0)	0	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(16)	(0)	(16)

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.

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

($ 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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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Blake

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.

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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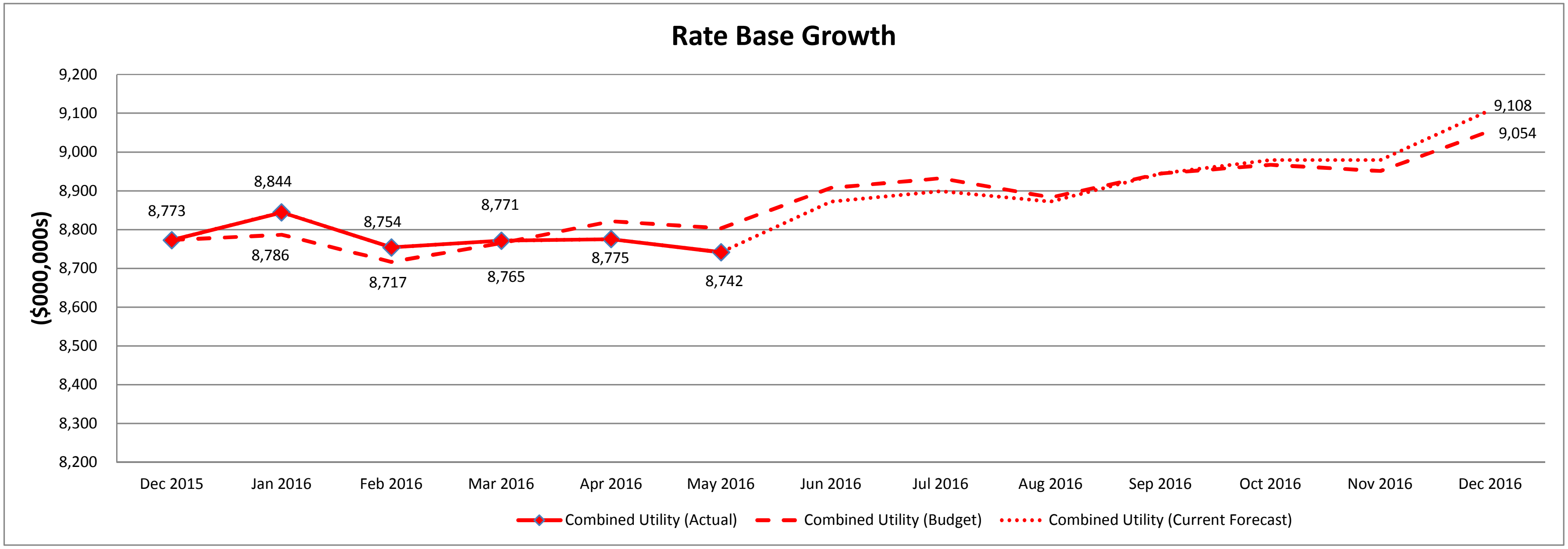

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Performance Report

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.

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.

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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.

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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

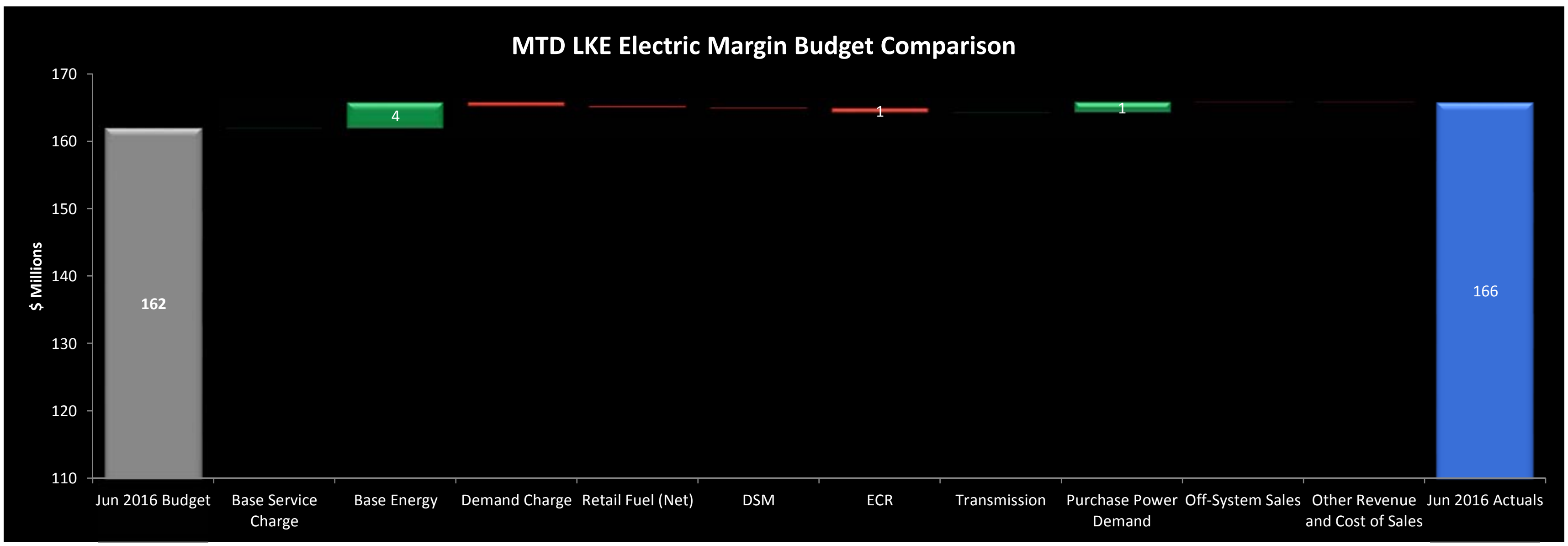
	Volume	Price	Total Variance
Residential	5	1	5
Commercial	0	(1)	(0)
Industrial	(1)	0	(1)
Public Authority	(0)	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	0	(0)	(0)
Other	0	0	0
	4	(0)	4

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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Electric Gross Margin Analysis - YTD
($ Millions)

June 2016

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

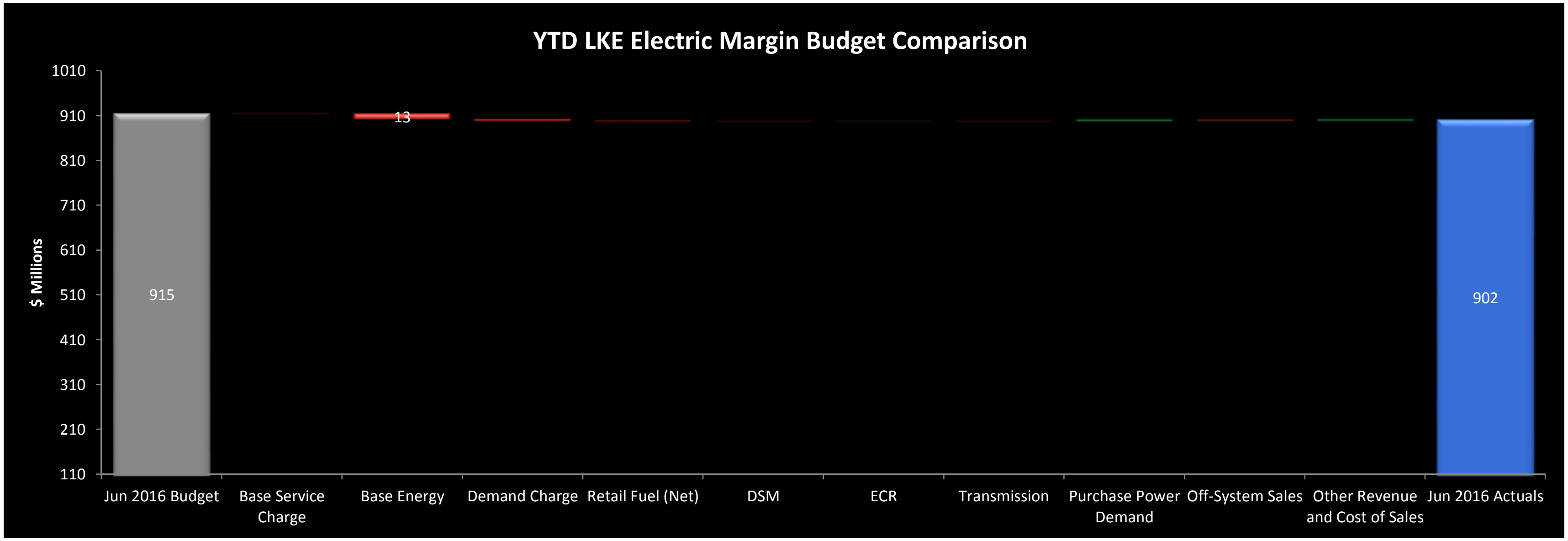
	Volume	Price	Total Variance
Residential	(9)	3	(6)
Commercial	0	(4)	(4)
Industrial	(3)	1	(1)
Public Authority	(0)	0	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(13)	(0)	(13)

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.

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Gas Gross Margin — June 2016

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	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.

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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.

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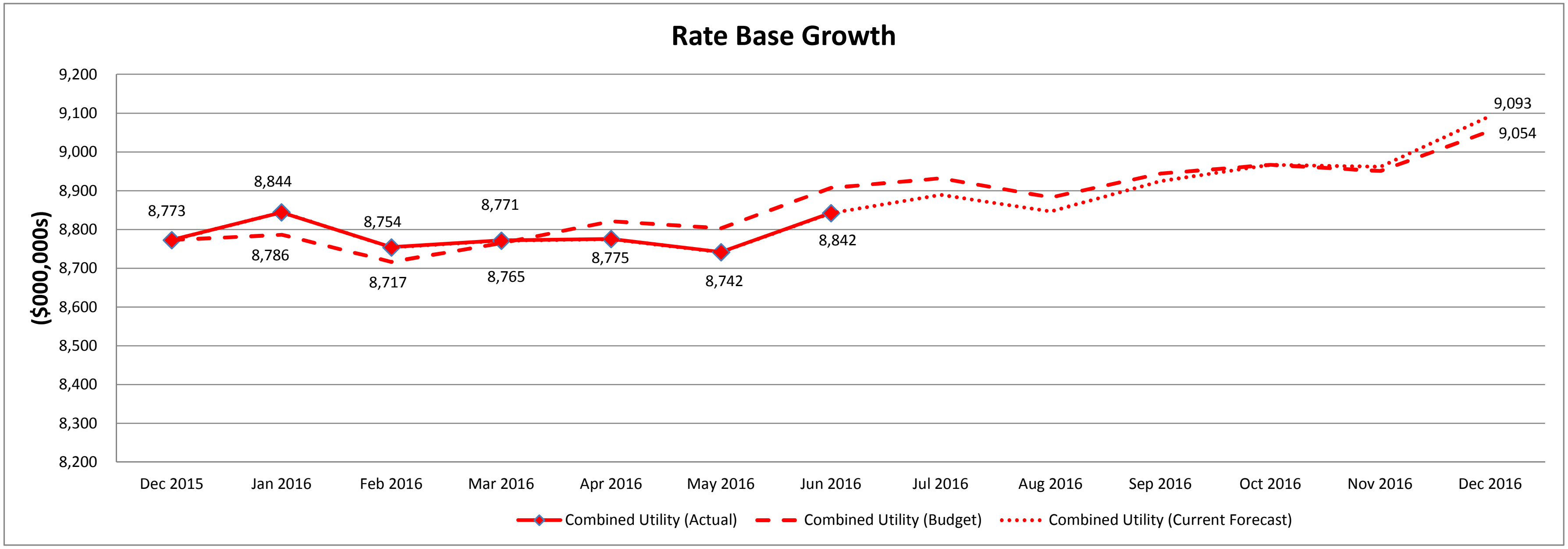
Balance Sheet - KU | June 2016

($ 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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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	Budget	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.

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

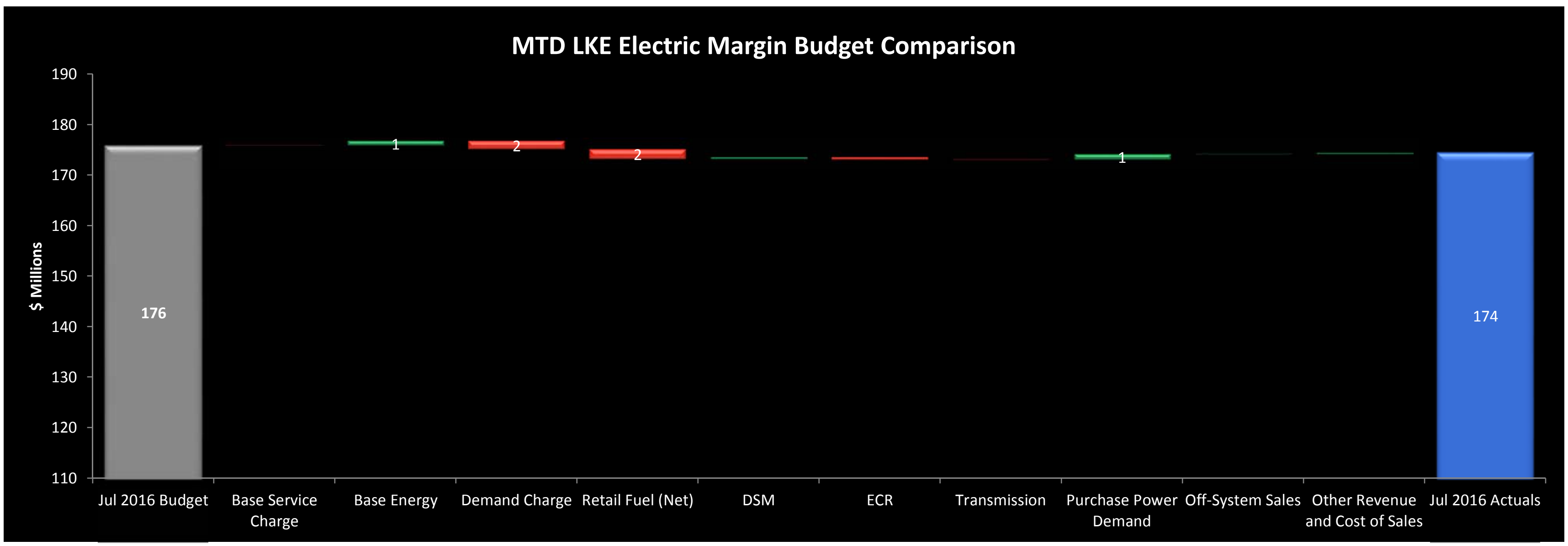
	Volume	Price	Total Variance
Residential	1	1	2
Commercial	1	(1)	0
Industrial	(1)	0	(1)
Public Authority	0	(0)	(0)
Street Lights	(0)	0	(0)
Municipals	(0)	(0)	(0)
Other	0	0	0
	2	(1)	1

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

($ Millions)

July 2016

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

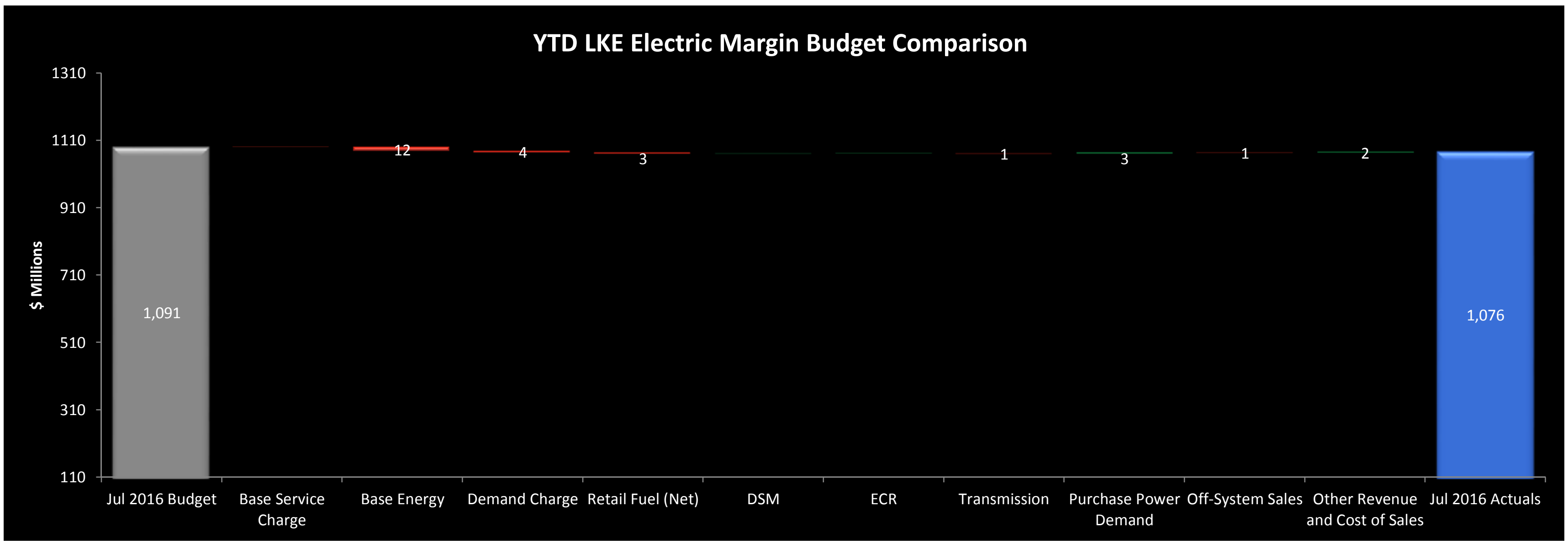
	Volume	Price	Total Variance
Residential	(7)	4	(4)
Commercial	1	(5)	(4)
Industrial	(4)	1	(2)
Public Authority	(0)	(0)	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(11)	(1)	(12)

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				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	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

($ 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.

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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 July 2016

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.

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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.

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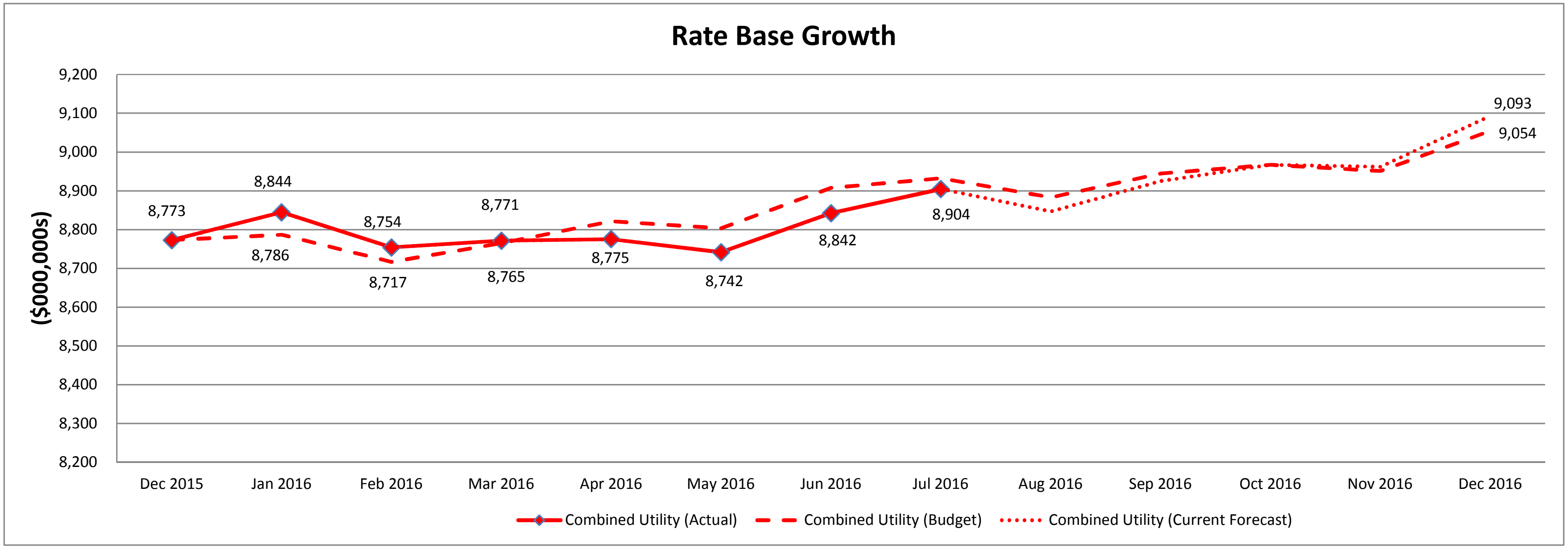

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Performance Report

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.

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	YTD Budget	YTD 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.

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.

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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
($ Millions)

August 2016

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

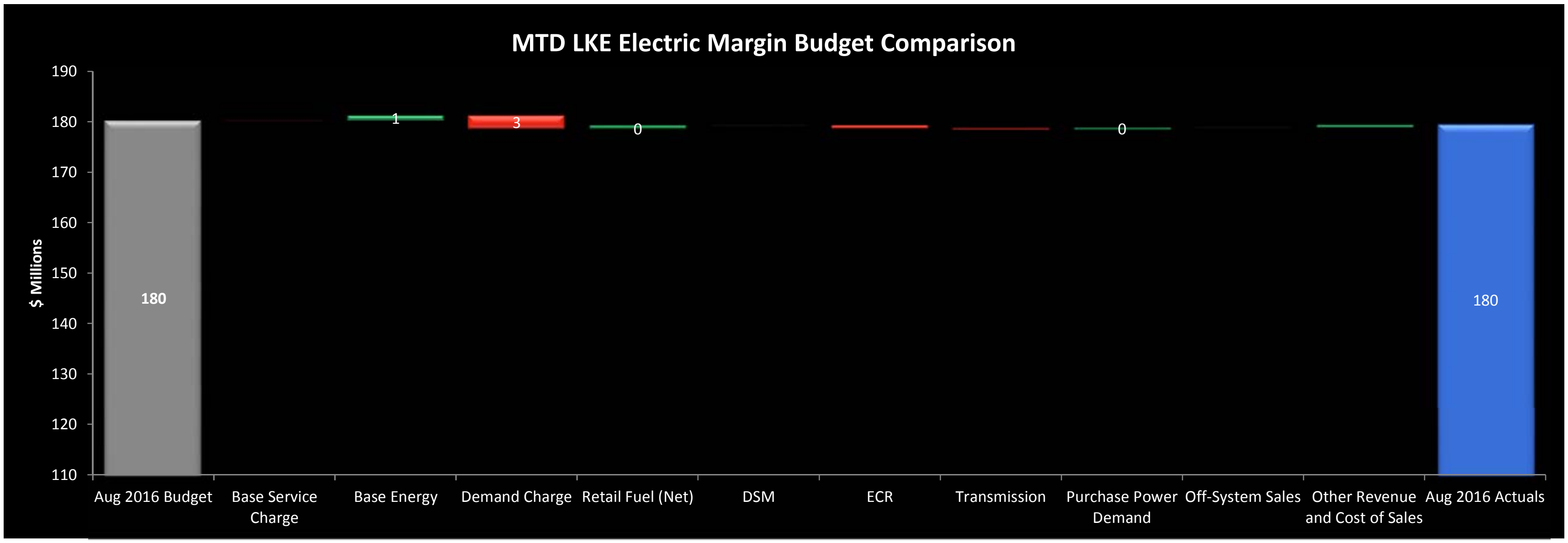
	Volume	Price	Total Variance
Residential	(1)	1	0
Commercial	2	(1)	1
Industrial	(0)	0	(0)
Public Authority	1	(0)	0
Street Lights	(0)	0	0
Municipals	0	(0)	(0)
Other	0	0	0
	2	(1)	1

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.

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Electric Gross Margin Analysis - YTD **August 2016**
($ Millions)

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

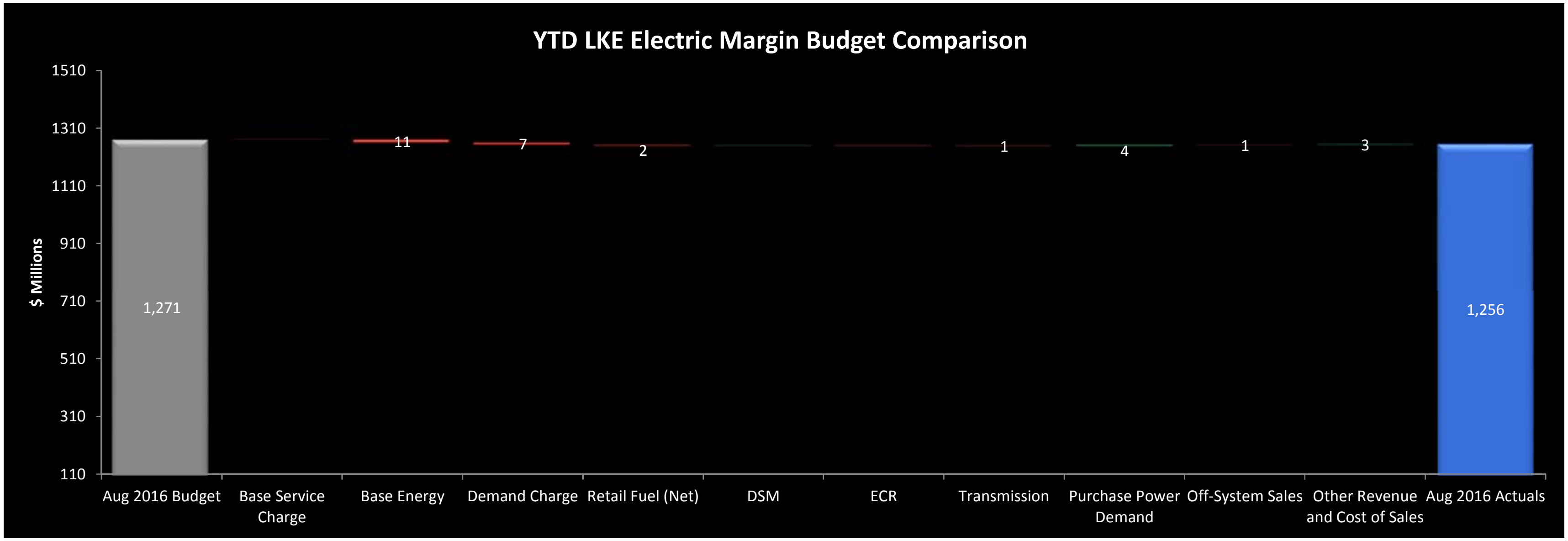
	Volume	Price	Total Variance
Residential	(8)	4	(3)
Commercial	3	(6)	(3)
Industrial	(4)	2	(2)
Public Authority	0	(0)	(0)
Street Lights	(1)	1	(0)
Municipals	(0)	(1)	(1)
Other	0	0	0
	(9)	(1)	(11)

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.

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Gas Gross Margin — August 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)**	**$ 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 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	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 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	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

O&M **August 2016**

($ 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.

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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.

Attachment to Filing Requirement
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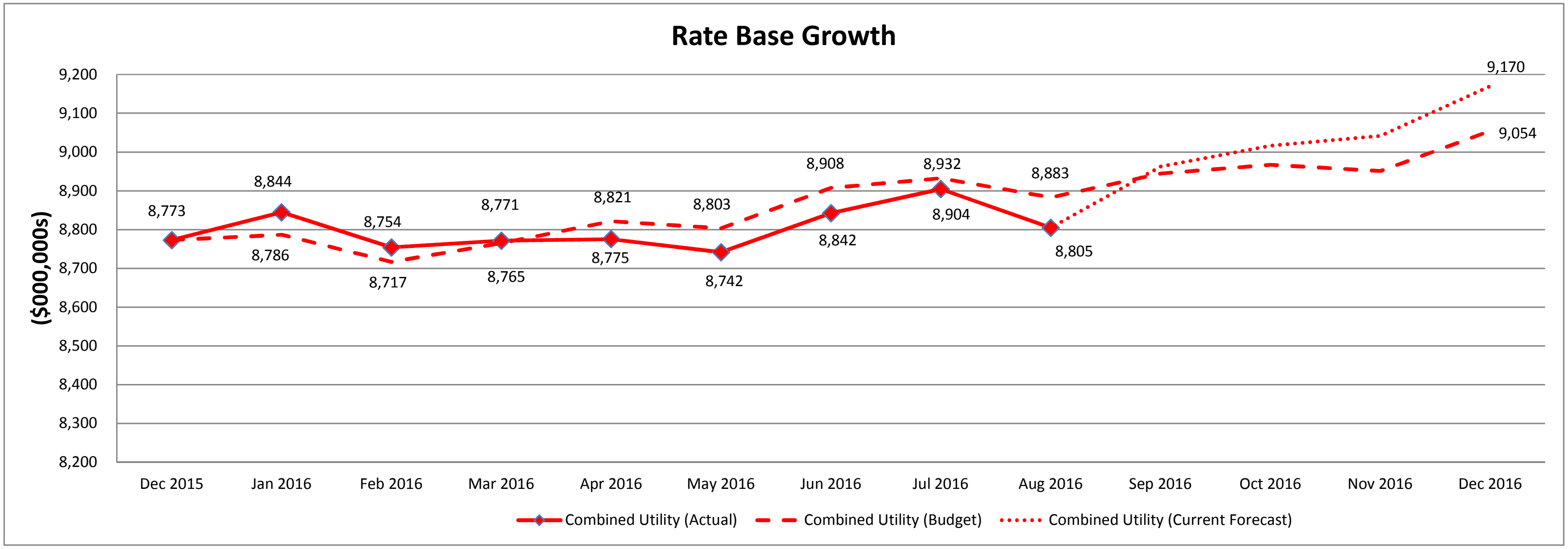

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Performance Report

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	YTD Budget	YTD 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.

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

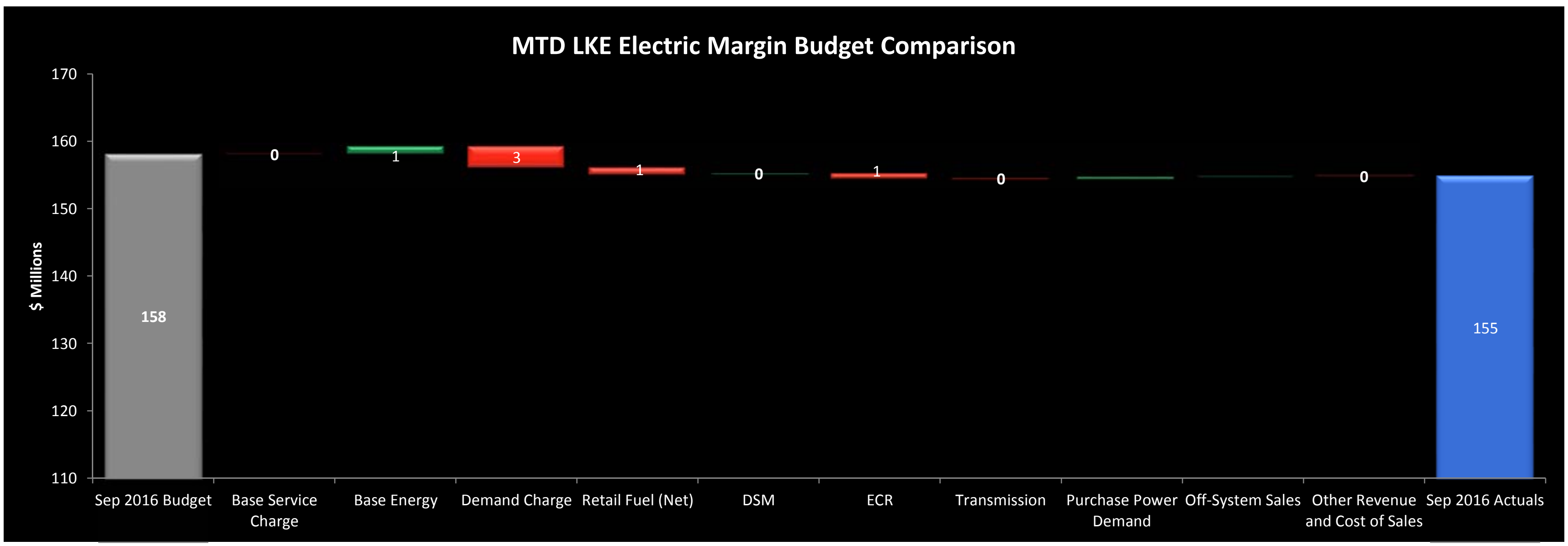
	Volume	Price	Total Variance
Residential	(1)	0	(1)
Commercial	3	(1)	2
Industrial	(0)	0	(0)
Public Authority	1	(0)	1
Street Lights	(0)	0	0
Municipals	0	(0)	(0)
Other	0	0	0
	2	(1)	1

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 **September 2016**
($ Millions)

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

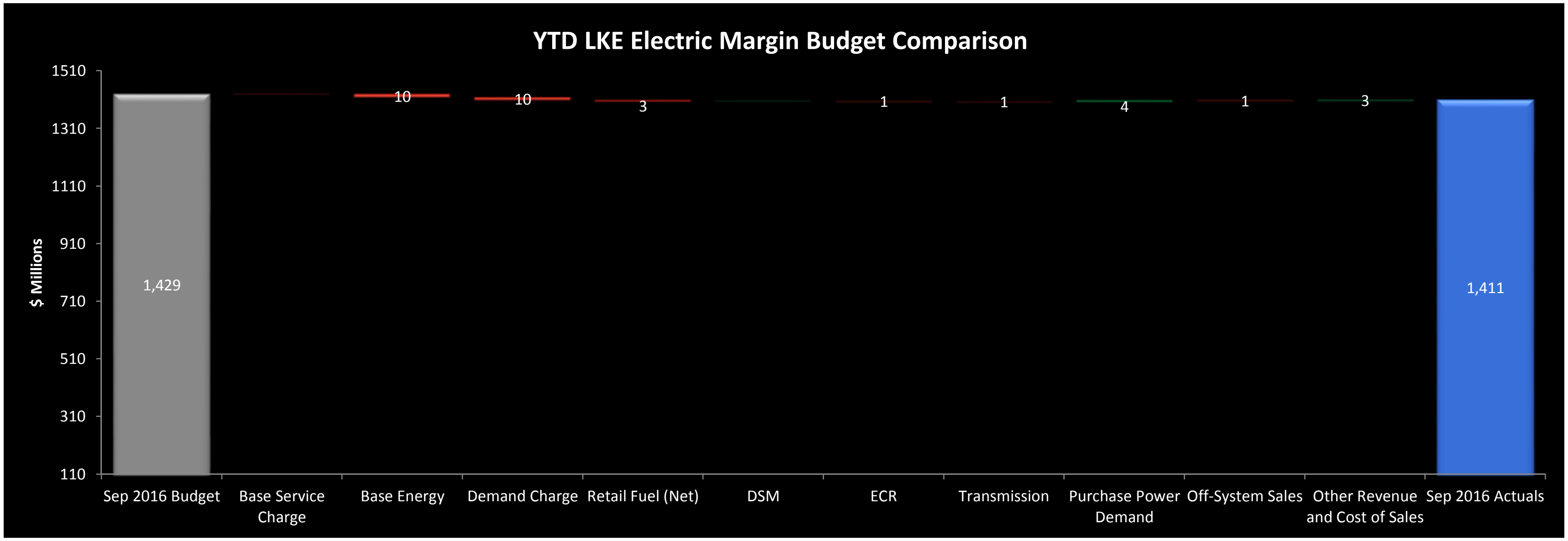
	Volume	Price	Total Variance
Residential	(9)	5	(4)
Commercial	6	(7)	(1)
Industrial	(4)	2	(3)
Public Authority	1	(1)	0
Street Lights	(1)	1	(0)
Municipals	(0)	(2)	(2)
Other	0	0	0
	(7)	(2)	(10)

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.

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 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	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 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	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	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 — 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

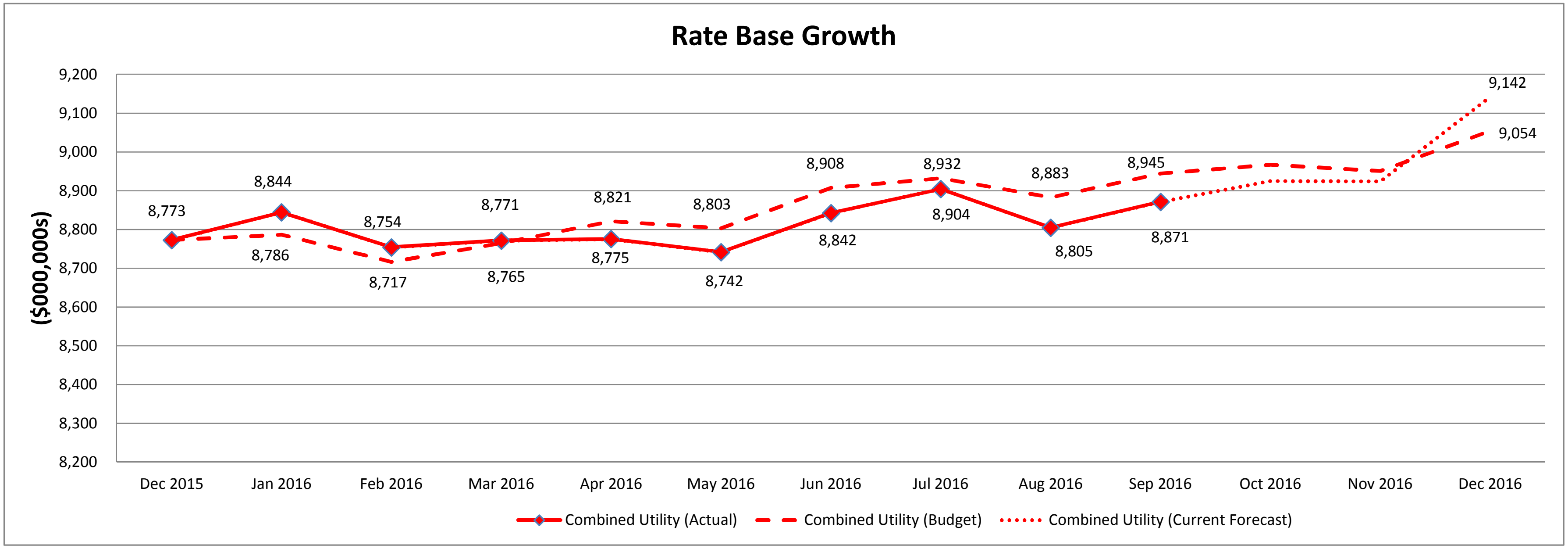
($ Millions)

	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)

Blake



Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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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	0.1%		
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.

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

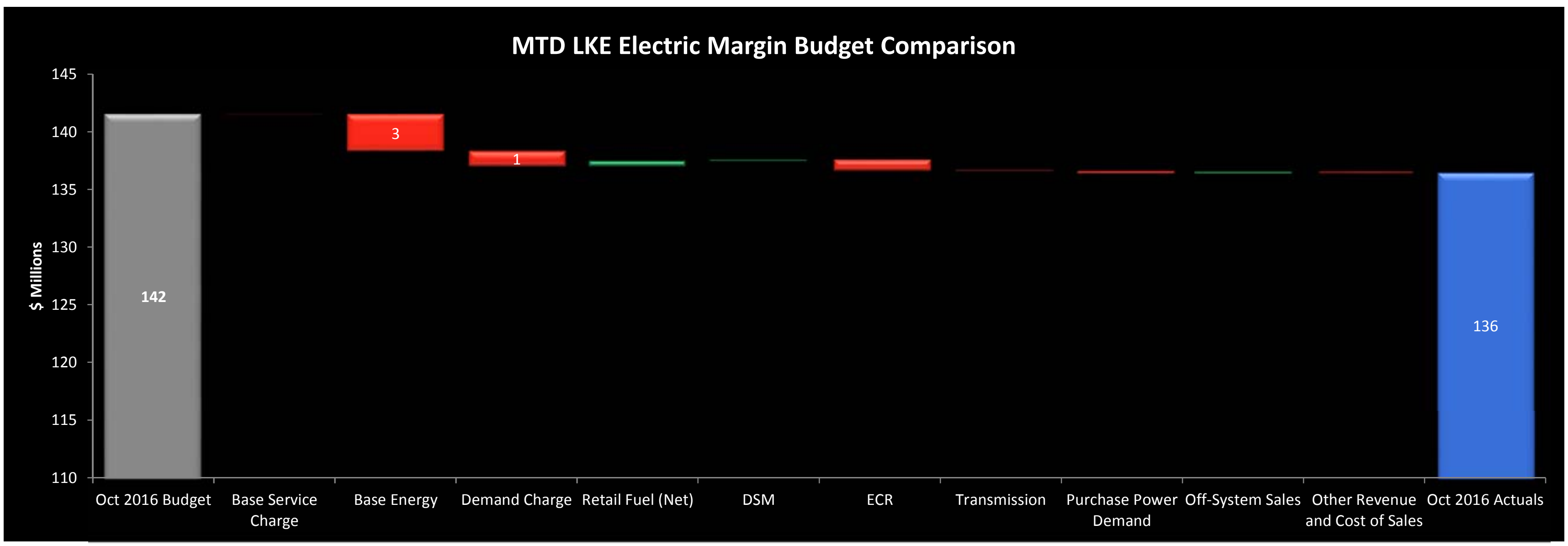
	Volume	Price	Total Variance
Residential	(3)	0	(3)
Commercial	0	(1)	(0)
Industrial	(0)	0	(0)
Public Authority	0	(0)	0
Street Lights	(0)	0	0
Municipals	(0)	(0)	(0)
Other	0	0	0
	(3)	(0)	(3)

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.

Electric Gross Margin Analysis - YTD — **October 2016**
($ Millions)

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

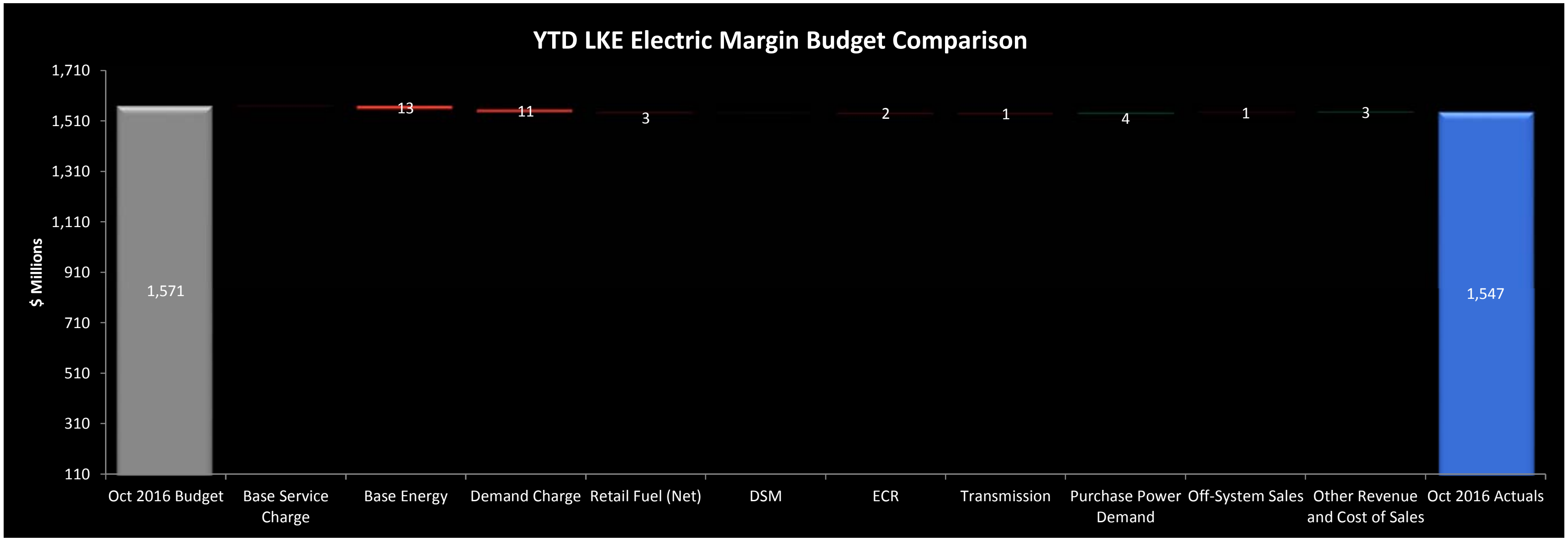
	Volume	Price	Total Variance
Residential	(12)	5	(7)
Commercial	6	(8)	(2)
Industrial	(5)	2	(3)
Public Authority	1	(1)	1
Street Lights	(1)	1	0
Municipals	(0)	(2)	(2)
Other	0	0	0
	(10)	(2)	(13)

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 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	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 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	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

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($ 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	 Budget YTD	LG&E 2016 Actual YTD	 Budget YTD	KU 2016 Actual YTD	 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	 2018	LG&E 2016 BP 2017	 2018	KU 2016 BP 2017	 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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)

Blake

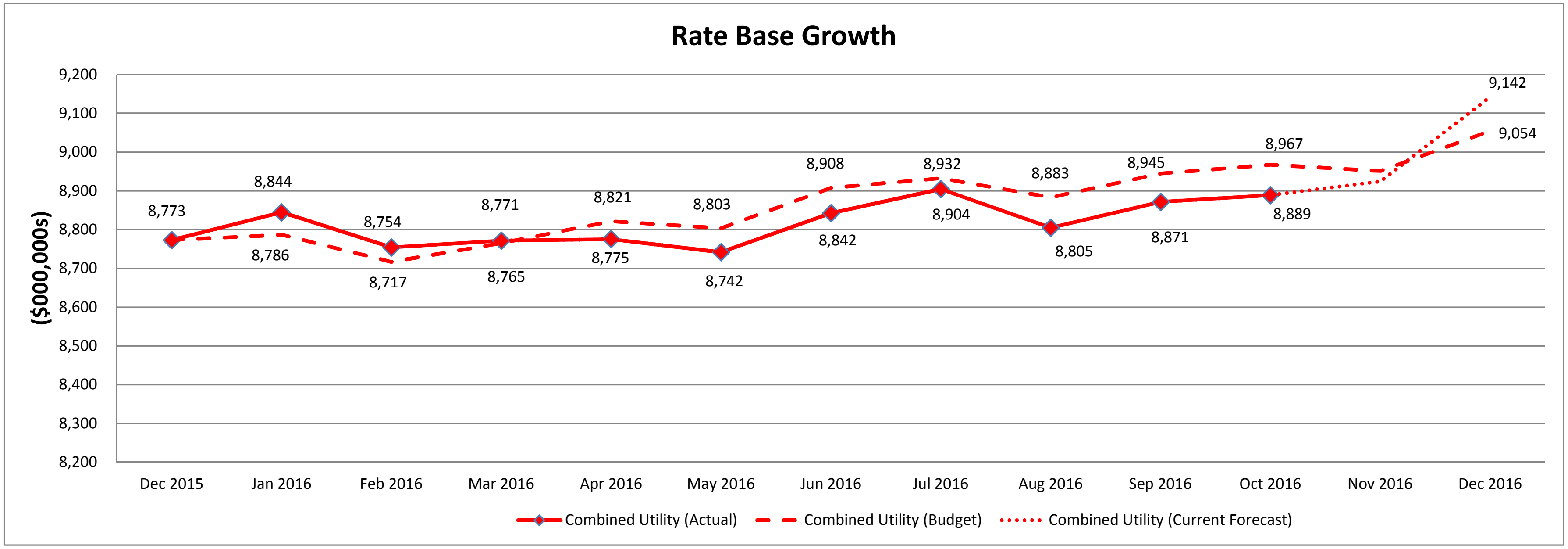
Balance Sheet - KU

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.


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
8,786
8,754
8,717
8,771
8,765
8,821
8,775
8,803
8,742
8,908
8,842
8,932
8,904
8,883
8,805
8,945
8,871
8,967
8,889
9,142
9,054
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)