Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 6 - 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, which includes the abbreviated newspaper notice, the list of newspapers publishing the notice, the full newspaper notice, and the bill insert.

The Commission granted the request of KU and Louisville Gas and Electric Company ("LG&E") to publish an abbreviated newspaper customer notice (see attached).[1]

[1] *In the Matters of: Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates; Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates,* Case Nos. 2025-00113 and 2025-00114, Order (Ky. PSC May 5, 2025), Ordering Paragraph.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)
KENTUCKY UTILITIES COMPANY FOR AN	)
ADJUSTMENT OF ITS ELECTRIC RATES	)
AND APPROVAL OF CERTAIN	) **CASE NO. 2025-00113**
REGULATORY AND ACCOUNTING	)
TREATMENTS	)

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 30th day of May, 2025, filed an application with the Kentucky Public Service Commission ("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 is being given in all respects as required by the Commission's Order of May 5, 2025 in this proceeding, as follows:

I 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 15th day of May 2025, 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 the 23rd day of May 2025, an abbreviated notice in conformity with the Commission's Order of May 5, 2025 in this proceeding of the filing of KU's Application. A copy of said notice is attached hereto as Exhibit A. A list of newspapers of general circulation throughout the Commonwealth of Kentucky in which KU's customers affected reside is attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion pursuant to 807 KAR 5:001, Section 17(3)(b).

Beginning on the 23rd day of May 2025, KU posted on its website a copy of the full customer notice attached hereto as Exhibit C, that 807 KAR 5:001, Section 17 requires and a hyperlink to the location on the Commission's website where the case documents and tariff filings are available.

Beginning on the 30th day of May 2025, KU posted on its website a complete copy of KU's application in this case. KU's application filed with the Commission on the 30th day of May 2025, includes the customer notice as a separate document labeled "Customer Notice of Rate Adjustment."

In addition, beginning on the 15th day of May 2025, KU issued press advisories to all known news media organizations who cover the areas within its certified territory advising of the filing of its application and including a hyperlink to the location on KU's and the Commission's websites where case documents and tariff filings will be available.

Beginning on the 4th day of June 2025, KU will include 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 D. Both the notice being published in newspapers and the bill inserts being sent to customers include the web address to the online posting.

On the 30th day of May 2025, KU notified by electronic mail the chief executive officer or legal counsel of each entity that had been granted intervention or otherwise permitted to participate in its last general rate case proceeding of the filing of the application and provided a hyperlink to the location on the Commission's website where case documents and tariff filings are available.

Given under my hand this 30th day of May, 2025.

Robert M. Conroy
Vice President, State Regulation and Rates
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Subscribed and sworn to before me, a Notary Public in and before Jefferson County, Kentucky this 30th day of May, 2025.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

Exhibit A

Notice of the Filing – Abbreviated

CUSTOMER NOTICE OF RATE ADJUSTMENT

PLEASE TAKE NOTICE that, in a May 30, 2025, Application, Kentucky Utilities Company ("KU") is seeking approval by the Kentucky Public Service Commission of an adjustment of its electric rates and charges to become effective on and after July 1, 2025.

KU CURRENT AND PROPOSED RESIDENTIAL ELECTRIC RATES

Residential Service – Rate RS

	Current	Proposed
Basic Service Charge per Day:	$ 0.53	$0.64
Plus an Energy Charge per kWh:		
Infrastructure:	$ 0.06880	$0.08034
Variable:	$ 0.03653	$0.03863
Total:	$ 0.10533	$0.11897

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

	Current	Proposed
Basic Service Charge per Day:	$ 0.53	$0.64
Plus an Energy Charge per kWh:		
Off-Peak Hours (Infrastructure):	$ 0.03560	$0.04152
Off-Peak Hours (Variable):	$ 0.03653	$0.03863
Off-Peak Hours (Total):	$ 0.07213	$0.08015
On-Peak Hours (Infrastructure):	$ 0.18813	$0.21942
On-Peak Hours (Variable):	$ 0.03653	$0.03863
On-Peak Hours (Total):	$ 0.22466	$0.25805

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

	Current	Proposed
Basic Service Charge per Day:	$ 0.53	$0.64
Plus an Energy Charge per kWh (Infrastructure):	$ 0.01600	$0.01866
Plus an Energy Charge per kWh (Variable):	$ 0.03653	$0.03863
Plus an Energy Charge per kWh (Total):	$ 0.05253	$0.05729
Plus a Demand Charge per kW:		
Base Hours	$ 3.92	$4.57
Peak Hours	$ 10.13	$11.81

KU is also proposing changes to the rates for other customer classes. These customer classes and their associated annual revenue changes are listed in the tables shown below. KU is also proposing to change the text of some of its rate schedules and other tariff provisions. KU's proposed rates reflect a proposed annual increase in electric revenues of approximately 11.5%.

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	1,085	99,997,335	13.55	18.15	13.55
Residential Time-of-Day	1,245	23,833	13.05	18.53	13.05
General Service	1,657	25,335,181	9.21	24.41	9.22
General Time-of-Day	19,507	2,400	8.22	198.49	8.22
All Electric School	25,620	1,449,553	10.91	314.15	10.91
Power Service	30,651	17,655,788	9.15	349.93	9.15
Time-of-Day Secondary	189,538	17,929,669	10.87	1,846.64	10.87
Time-of-Day Primary	1,242,574	33,834,832	11.15	10,609.74	11.15
Retail Transmission	7,387,224	13,634,683	11.00	54,105.89	11.00
Extremely High Load Factor	New Rate Schedule				
Fluctuating Load Service	44,229,667	2,528,016	6.90	210,667.98	6.90
Outdoor Lights	51	3,624,095	11.37	1.67	11.40
Lighting Energy	2,473	42,734	11.14	21.99	11.14
Traffic Energy	146	26,391	10.58	1.91	10.60
Outdoor Sports Lighting	4,627	(37)	(0.04)	(0.52)	(0.04)
Rider – CSR	N/A	0	0.00	0.00	0.00

KU is proposing to expand the number of customers limit of GTOD-E and GTOD-D customers to a maximum of 500 customers combined.

KU is proposing to migrate all PS customers from a maximum load charge per kW to kVA. In addition, KU is proposing to transition all PS customers from a seasonal maximum load charge to a time-differentiated 3-tier maximum load charge, similar to the TODS, TODP, and RTS rate schedules. New PS service initiated on or after January 1, 2026 will be required to enter into a contract for an initial term of one year.

KU is proposing a new rate schedule titled Extremely High Load Factor Service. This rate schedule will be for customers contracting for capacity greater than 100 MVA and an average monthly load factor above 85%.

KU is proposing to split its wireline pole attachment charge into two charges, a two-user wireline pole attachment charge and a three-user wireline pole attachment charge.

KU is proposing to add an adjustment clause called Renewable Power Purchase Agreement. This adjustment clause will recover the cost of renewable generation power purchase agreements approved by the Commission.

KU is proposing to add an optional program called Pre-Pay. This program will give residential customers with AMI meters the option of moving from traditional post-paid service to a deposit-free pre-paid service.

KU is proposing to expand the Terms and Conditions rules for Deposits. This expansion looks to provide clarity to the business processes surrounding deposits and makes deposits mandatory for customers taking service under TODS, TODP, RTS, FLS and EHLF.

KU is proposing to modify the Terms and Conditions related to Billing by making paperless billing the default option for new customers and for those whom the Company has an email address.

KU is proposing a new tariff in its Terms and Conditions for Rules for Transmission-Level Retail Electric Service Studies and Related Implementation Costs. This will apply to any proposed retail electric service requiring KU to submit a Transmission Service Request to its Independent Transmission Organization.

KU is proposing new terms and conditions for Net Metering Service Interconnection Guidelines.

<u>Other Charges</u>

KU is proposing the following revisions to other charges in the tariff:

Other Charges	**Current Charge**	**Proposed Charge**
Wireline Pole Attachment	$7.25	Removed
Two-User Wireline Pole Attachment	New	$10.13
Three-User Wireline Pole Attachment	New	$10.46
Linear Foot of Duct	$0.81	$1.22
Wireless Facility at Top of Company Pole	$36.25	$51.46
Net Metering Service-2 Bill Credit	$0.07534	$0.03859
Returned Payment Charge	$3.50	$3.00
Meter Test Charge	$79.00	$89.00
Meter Pulse Charge	$21.00	$24.00
Disconnect/Reconnect Service Charge w/o remote service switch	$37.00	$87.00
Disconnect/Reconnect Service Charge w/ remote service switch	$0.00	$0.00
Unauthorized Connection Charge – without meter replacement	$45.00	$57.00
Unauthorized Connection Charge – for single-phase standard meter replacement	$66.00	$78.00
Unauthorized Connection Charge – for single-phase AMR meter replacement	$87.00	$99.00
Unauthorized Connection Charge – for single-phase AMI meter replacement	$149.00	$151.00
Unauthorized Connection Charge – for three-phase meter replacement	$154.00	$167.00
Unauthorized Connection Charge – for three-phase AMI meter replacement	New	$256.00
Advanced Meter Opt-Out Charge (One-Time)	$39.00	$74.00
Advanced Meter Opt-Out Charge (Monthly)	$15.00	$24.00
Redundant Capacity - Secondary	$1.33	$2.26
Redundant Capacity - Primary	$0.90	$1.65
EVSE – Networked (Option A) Single Charger	$132.09	$191.81
EVSE – Networked (Option A) Dual Charger	$193.62	$330.34

EVSE – Networked (Option B) Single Charger	New	$161.21
EVSE – Networked (Option B) Dual Charger	New	$254.60
EVSE – Non-Networked Single Charger	$80.14	$85.01
EVSE-R – Networked (Option A) Single Charger	$121.79	$144.03
EVSE-R – Networked (Option A) Dual Charger	$173.02	$234.79
EVSE-R – Networked (Option B) Single Charger	New	$113.44
EVSE-R – Networked (Option B) Dual Charger	New	$159.05
EVSE-R – Non-Networked Single Charger	$30.58	$37.24
EVC-L2 – Charge per kWh	New	$0.25
EVC-FAST – Charge per kWh	$0.25	$0.25
Solar Share Program Rider (One-Time)	$799.00	$799.00
Solar Share Program Rider (Monthly)	$5.55	$5.55
Excess Facilities – with no CIAC	1.14%	1.27%
Excess Facilities – with CIAC	0.46%	0.51%
TS – Temporary-to-Permanent	15%	15%
TS – Seasonal	100%	100%
SQF/LQF Solar: Single-Axis Tracking; Distribution; 2-Year PPA; Energy	$30.43	$33.02
SQF/LQF Solar: Single-Axis Tracking; Distribution; 7-Year PPA; Energy	$32.16	$38.50
SQF/LQF Solar: Single-Axis Tracking; Transmission; 2-Year PPA; Energy	$29.05	$31.52
SQF/LQF Solar: Single-Axis Tracking; Transmission; 7-Year PPA; Energy	$30.71	$36.75
SQF/LQF Solar: Fixed Tilt; Distribution; 2-Year PPA; Energy	$30.73	$33.05
SQF/LQF Solar: Fixed Tilt; Distribution; 7-Year PPA; Energy	$32.56	$38.59
SQF/LQF Solar: Fixed Tilt; Transmission; 2-Year PPA; Energy	$29.33	$31.55
SQF/LQF Solar: Fixed Tilt; Transmission; 7-Year PPA; Energy	$31.09	$36.84
SQF/LQF Wind; Distribution; 2-Year PPA; Energy	$29.27	$32.07
SQF/LQF Wind; Distribution; 7-Year PPA; Energy	$31.55	$36.59
SQF/LQF Wind; Transmission; 2-Year PPA; Energy	$27.94	$30.62
SQF/LQF Wind; Transmission; 7-Year PPA; Energy	$30.12	$34.93
SQF/LQF Other Technologies; Distribution; 2-Year PPA; Energy	$29.39	$31.99
SQF/LQF Other Technologies; Distribution; 7-Year PPA; Energy	$31.96	$37.06
SQF/LQF Other Technologies; Transmission; 2-Year PPA; Energy	$28.05	$30.54
SQF/LQF Other Technologies; Transmission; 7-Year PPA; Energy	$30.51	$35.38
SQF/LQF Solar: Single-Axis Tracking; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Single-Axis Tracking; Distribution; 7-Year PPA; Capacity	$12.81	$0
SQF/LQF Solar: Single-Axis Tracking; Transmission; 2-Year PPA; Capacity	$0	$0

SQF/LQF Solar: Single-Axis Tracking; Transmission; 7-Year PPA; Capacity	$12.03	$0
SQF/LQF Solar: Fixed Tilt; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Fixed Tilt; Distribution; 7-Year PPA; Capacity	$15.42	$0
SQF/LQF Solar: Fixed Tilt; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Fixed Tilt; Transmission; 7-Year PPA; Capacity	$14.49	$0
SQF/LQF Wind; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Wind; Distribution; 7-Year PPA; Capacity	$10.10	$0
SQF/LQF Wind; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Wind; Transmission; 7-Year PPA; Capacity	$9.49	$0
SQF/LQF Other Technologies; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Other Technologies; Distribution; 7-Year PPA; Capacity	$8.93	$18.94
SQF/LQF Other Technologies; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Other Technologies; Transmission; 7-Year PPA; Capacity	$8.39	$17.80

A detailed notice of all proposed revisions and a complete copy of the proposed tariffs containing the proposed text changes, terms and conditions and rates may be obtained by submitting a written request by e-mail to myaccount@lge-ku.com or by mail to Kentucky Utilities Company, ATTN: Rates Department, 2701 Eastpoint Parkway, Louisville, Kentucky, 40223, or by visiting KU's website at https://lge-ku.com/ku-2025-rate-case.

A person may examine KU's application at KU's office at One Quality Street, Lexington, Kentucky, 40507, and at KU's website at https://lge-ku.com/ku-2025-rate-case. 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 may view and download the application 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 email to psc.info@ky.gov. All comments should reference Case No. 2025-00113.

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 this notice, the Commission may take final action on the application.

Exhibit B

Listing of Newspapers Publishing Notice

<u>List of newspapers running the Notice to Kentucky Utilities Company Customers.</u>

Arlington Carlisle Weekly
Barbourville Mnt. Advocate
Bardstown KY Standard
Bardwell Carlilse Co. News
Beattyville Enterprise
Bedford Trimble Banner
Berea Citizen
Brandenburg Meade Co Messenger
Brooksville Bracken Co.
Brownsville Edmonson New
Calhoun McLean Co. New
Campbellsville Central KY
Carlisle Mercury
Carrollton News Democrat
Cave City Barren Co Progress
Central City Leader News
Central City Times Argus
Columbia Adair Comm. Voice
Columbia Adair Progress
Corbin Times Tribune
Cumberland Tri City News
Cynthiana Democrat
Dawson Springs Progress
Eddyville Herald Ledger
Elizabethtown News Enter
Falmouth Outlook
Flemingsburg Gazette
Frankfort State Journal
Florence Boone Recorder
Frankfort State Journal
Fulton Leader The Current
Georgetown Graphic
Greensburg Record Herald
Harlan Enterprise
Harrodsburg Herald
Hartford Ohio Co. Times
Henderson Gleaner
Hickman County Times
Hodgenville Larue Herald
Hopkinsville KY New Era
Irvine Estill Co. Tribune
Lagrange Oldham Era
Lancaster Central Record
Lawrenceburg Ander. News
Lebanon Enterprise
Leitchfield Grayson Co. News

Lexington Herald Leader
Liberty Casey Co. News
Link NKY
London Sentinel Echo
Louisville Courier Journal
Madisonville Messenger
Manchester Enterprise
Marion Crittenden Press
Maysville Ledger Independent
Middlesboro Daily News
Mt. Sterling Advocate
Mt. Vernon Signal
Munfordville Hart Co. News
New Castle Henry Co. Local
Nicholasville Jessamine
Owensboro Messenger Inquirer
Owenton News Herald
Owingsville Bath Outlook
Paducah Sun
Paris Bourbon Co Citizen
Pineville Sun
Providence Journal Enter
Richmond Register
Robertson Co. News
Rowan Co. News
Russell Springs Times
Sebree Banner
Shelbyville Sentinel News
Shepherdsville Pioneer
Smithland Livingston Ledger
Somerset Commonwealth
Springfield Sun
Stanford Interior Journal
Sturgis News
Taylorsville Spencer Magnet
The Advocate Messenger
Three Forks Tradition
Times Leader Princeton
Versailles Woodford Sun
Warsaw Gallatin News
Whitley City McCreary Voice
Wickliffe Advance Yeoman
Williamsburg News Journal
Williamstown Grant Co. News
Winchester Sun

Exhibit C

Notice of the Filing – Full Notice

CUSTOMER NOTICE OF RATE ADJUSTMENT

Notice is hereby given that, in a May 30, 2025 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 July 1, 2025.

KU CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS

Rate:

	Current	Proposed
Basic Service Charge per Day:	$0.53	$0.64
Plus an Energy Charge per kWh:		
Infrastructure	$0.06880	$0.08034
Variable	$0.03653	$0.03863
Total	$0.10533	$0.11897

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

Availability:

Current

Available as an option to Customers otherwise served under Rate RS.

1. Service under this rate schedule is limited to a maximum of five hundred (500) Customers taking service on Rates 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 GS (where the Rate GS service is used in conjunction with a Rate 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 Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule.

Proposed

This optional rate is available to Customers who qualify for service under Rate RS and have an electric AMI meter.

1. Service under this rate schedule is limited to a maximum of five hundred (500) Customers taking service on Rates 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 eligible for Standard Rate GS (where the Rate GS service is used in conjunction with a Rate 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 Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule.

Rate:

	Current	Proposed
Basic Service Charge per Day:	$ 0.53	$0.64
Plus an Energy Charge per kWh:		
Off-Peak Hours		
Off-Peak Hours (Infrastructure):	$ 0.03560	$0.04152
Off-Peak Hours (Variable):	$ 0.03653	$0.03863
Off-Peak Hours (Total):	$ 0.07213	$0.08015
On-Peak Hours		
On-Peak Hours (Infrastructure):	$ 0.18813	$0.21942
On-Peak Hours (Variable):	$ 0.03653	$0.03863
On-Peak Hours (Total):	$ 0.22466	$0.25805

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

Availability:

Current

Available as an option to Customers otherwise served under Rate RS.

1. Service under this rate schedule is limited to a maximum of five hundred (500) Customers taking service on Rates 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 GS (where the Rate GS service is used in conjunction with a Rate 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 Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule.

Proposed

This optional rate is available to Customers who qualify for service under Rate RS and have an electric AMI meter.

1. Service under this rate schedule is limited to a maximum of five hundred (500) Customers taking service on Rates 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 as an option to Customers eligible for Standard Rate GS (where the Rate GS service is used in conjunction with a Rate 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 Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule.

Rate:

	Current	Proposed
Basic Service Charge per Day:	$ 0.53	$0.64
Plus an Energy Charge per kWh (Infrastructure):	$ 0.01600	$0.01866
Plus an Energy Charge per kWh (Variable):	$ 0.03653	$0.03863
Plus an Energy Charge per kWh (Total):	$ 0.05253	$0.05729
Plus a Demand Charge per kW:		
Base Hours	$ 3.92	$4.57
Peak Hours	$ 10.13	$11.81

Volunteer Fire Department Service - Rate VFD

Rate:

	Current	Proposed
Basic Service Charge per Day:	$0.53	$0.64
Plus an Energy Charge per kWh:		
Infrastructure	$ 0.06880	$0.08034
Variable	$ 0.03653	$0.03863
Total	$ 0.10533	$0.11897

General Service – Rate GS

Rate:

Single-Phase	Current	Proposed
Basic Service Charge per Day:	$ 1.35	$1.54
Plus an Energy Charge per kWh		
Infrastructure	$ 0.09176	$0.10079
Variable	$ 0.03706	$0.03878
Total	$ 0.12882	$0.13957
Three-Phase	**Current**	**Proposed**
Basic Service Charge per Day:	$2.15	$2.45
Plus an Energy Charge per kWh		
Infrastructure	$ 0.09176	$0.10079
Variable	$ 0.03706	$0.03878
Total	$ 0.12882	$0.13957

General Time-of-Day Energy Service – Rate GTOD-Energy

Availability:

Current

Available to GS Customers participating in the Demand-Side Management ("DSM") program titled Non-Residential Advanced Metering Systems Incentive on Sheet No. 86.6.

A Customer electing to take service under this rate schedule who subsequently elects to take service under the standard rate GS will not be allowed to return to this rate for 12 months from the date of exiting this rate schedule.

Proposed

Service under this optional rate schedule is limited to a maximum of five-hundred (500) Customers taking service on Rates GTOD-Demand and GTOD-Energy combined that are eligible for Rate GS and have an electric AMI meter. Company will accept Customers on a first-come-first-served basis.

A Customer electing to take service under this rate schedule who subsequently elects to take service under the standard rate GS will not be allowed to return to this rate for 12 months from the date of exiting this rate schedule.

Rate:

	Current	Proposed
Basic Service Charge per Day (Single-Phase):	$ 1.35	$1.54
Basic Service Charge per Day (Three-Phase):	$ 2.15	$2.45
Plus an Energy Charge per kWh:		
Off-Peak Hours		
Off-Peak Hours (Infrastructure):	$0.05316	$0.05843
Off-Peak Hours (Variable):	$0.03706	$0.03878
Off-Peak Hours (Total):	$0.09022	$0.09721
On-Peak Hours		
On-Peak Hours (Infrastructure):	$0.27125	$0.29816
On-Peak Hours (Variable):	$0.03706	$0.03878
On-Peak Hours (Total):	$0.30831	$0.33694

General Time-of-Day Demand Service - Rate GTOD-Demand

Availability:

Current

Available to GS Customers participating in the Demand-Side Management ("DSM") program titled Non-Residential Advanced Metering Systems Incentive on Sheet No. 86.6.

A Customer electing to take service under this rate schedule who subsequently elects to take service under the standard rate GS will not be allowed to return to this rate for 12 months from the date of exiting this rate schedule.

Proposed

Service under this optional rate schedule is limited to a maximum of five-hundred (500) Customers taking service on Rates GTOD-Demand and GTOD-Energy combined that are eligible for Rate GS and have an electric AMI meter. Company will accept Customers on a first-come-first-served basis.

A Customer electing to take service under this rate schedule who subsequently elects to take service under the standard rate GS will not be allowed to return to this rate for 12 months from the date of exiting this rate schedule.

Rate:

	Current	Proposed
Basic Service Charge per Day (Single-Phase):	$1.35	$1.54
Basic Service Charge per Day (Three-Phase):	$2.15	$2.45
Plus an Energy Charge per kWh (Infrastructure):	$0.04145	$0.04556
Plus an Energy Charge per kWh (Variable):	$0.03706	$0.03878
Plus an Energy Charge per kWh (Total):	$0.07851	$0.08434
Plus a Demand Charge per kW:		
Base Hours	$5.47	$6.01
Peak Hours	$14.16	$15.56

All Electric School – Rate AES

Rate:

Single-Phase	**Current**	**Proposed**
Basic Service Charge per Day:	$2.80	$3.16
Plus an Energy Charge per kWh		
Infrastructure	$0.06770	$0.07743
Variable	$0.03676	$0.03870
Total	$0.10446	$0.11613
Three-Phase		
Basic Service Charge per Day:	$4.60	$5.19
Plus an Energy Charge per kWh		
Infrastructure	$0.06770	$0.07743
Variable	$0.03676	$0.03870
Total	$0.10446	$0.11613

Power Service – Rate PS

Rate:

Current

	Secondary	Primary
Basic Service Charge per day:	$2.96	$7.89
Plus an Energy Charge per kWh:	$0.03701	$0.03667
Plus a Demand Charge per kW:		
Summer Rate:		
(Five Billing Periods of May through September)	$26.50	$26.47
Winter Rate:		
(All other months)	$23.86	$23.88

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

Proposed

	Secondary	Primary
Basic Service Charge per day:	$3.40	$7.89
Energy Charge per kWh:	$0.03877	$0.03782
Maximum Load Charge per kVA:	Secondary	Primary
Peak Demand Period:	$12.22	$12.31
Intermediate Demand Period:	$9.84	$9.94
Base Demand Period:	$4.23	$3.32

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
1. the maximum measured load in the current billing period, or
2. 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:
1. the maximum measured load in the current billing period but not less than 50 kVA for secondary service

or 25 kVA for primary service, or
2. the highest measured load in the preceding eleven (11) monthly billing periods, or
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer

Determination of Maximum Load:
Current
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 ninety (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 ninety (90) percent in accordance with the following formula: (based on power factor measured at the time of maximum load).

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

Proposed
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 month.

New - 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 AM - 10 PM	1 PM - 7 PM
Weekends	All Hours		

All other months of October through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 AM - 10 PM	6 AM - 12 PM
Weekends	All Hours		

If a legal holiday falls on a weekday, it will be considered a weekday.

Term of Contract:
Current
Contracts under this rate may be required 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.
Proposed
For new service initiated on or after January 1, 2026, contracts under this rate will be required 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.

Time-of-Day Secondary Service Rate TODS

Rate:

	Current	Proposed
Basic Service Charge per Day	$7.32	$7.32
Plus an Energy Charge per kWh	$0.03372	$0.03868
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$8.69	$9.48
Intermediate Demand Period	$7.07	$7.71
Base Demand Period	$3.25	$3.55

Time-of-Day Primary Service Rate TODP

Rate:

	Current	Proposed
Basic Service Charge per Day	$ 10.77	$13.35
Plus an Energy Charge per kWh	$ 0.03026	$0.03771
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$ 9.60	$9.81
Intermediate Demand Period	$ 7.78	$7.94
Base Demand Period	$ 2.79	$2.86

Retail Transmission Service - Rate RTS

Rate:

	Current	Proposed
Basic Service Charge per Day	$49.28	$74.04
Plus an Energy Charge per kWh	$0.02966	$0.03692
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$9.31	$9.30
Intermediate Demand Period	$7.55	$7.54
Base Demand Period	$2.16	$2.16

New - Extremely High Load Factor Service – Rate EHLF

Applicable:
In all territory served.

Availability:
Available for Customers: 1) with a contract capacity greater than 100 MVA, and 2) an expected average monthly load factor above 85%.

The terms and conditions of service under this schedule shall apply upon a request for service by an eligible Customer but service to Customers under this schedule will not commence until the Company has sufficient capacity to meet the contractual load requirements.

Customer's initial contract term, load ramp, load ramp period, contract capacity, and other terms of service will be prescribed in the Electric Service Agreement executed between Company and Customer.

Rate:
Basic Service Charge per day: $74.04

Energy Charge per kWh: $0.03692

Maximum Load Charge per kVA: $19.00

Where:
the monthly billing demand for the Maximum Load Charge is the greater of:

1. the maximum measured load in the current billing period, or
2. the highest measured load in the preceding eleven (11) monthly billing periods, or
3. 80% 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:

Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Retired Asset Recovery	Sheet No. 89
Renewable Power Purchase Agreement Adjustment Clause	Sheet No. 90
Franchise Fee	Sheet No. 91
School Tax	Sheet No. 92

Determination of Maximum Load:
The load will be measured and will be the average kVA demand delivered to Customer during the 15-minute period of maximum use each 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 1% late payment charge will be assessed on the current month’s charges.

Term of Contract:
Contracts under this rate schedule shall be made for an Initial Contract Term of not less than fifteen (15) years.

Monthly billing will begin 30 days after the stated start date provided by the customer within the Electric Service Agreement whether or not electricity is being provided at that time.

Either party shall give at least 60 months advance written notice to the other party of its intention to discontinue service under the terms of this rate schedule. Such notice shall not reduce the Initial Contract Term except as provided for in the Exit Fee provision.

Changes to Contract Capacity:
Customer must provide Company 60 months advance written notice of a reduction of contract capacity after the first five (5) years of the Initial Contract Term, and such reduction of capacity will be subject to payment of a Capacity Reduction Fee and 60 months. The Capacity Reduction Fee shall be due and payable to the Company upon the effective date of the capacity reduction. The Capacity Reduction Fee shall be calculated

as the nominal value of the remaining minimum non-fuel revenue change from the original contract capacity over the remaining term.

Termination of Contract:
If Customer provides the required 60 months advance notice of termination prior to expiration of the Initial Contract term, Customer will be subject to payment of an Exit Fee. The Exit Fee shall be due and payable to the Company upon the effective date of the contract termination. The Exit Fee shall be calculated as the nominal value of the remaining minimum non-fuel revenue over the remaining term.

Collateral Requirements:
Customer or its guarantor shall provide collateral in the form of cash or Letter of Credit equal to 24 months of the minimum billed amounts at the largest contract capacity value. If Customer or its guarantor has an S&P Credit Rating of at least A and a Moody's Credit Rating of at least A2 with cash and cash equivalents on its audited balance sheet of at least 10 times the collateral requirement, Customer or its guarantor shall provide cash or a Letter of Credit equal to 12 months of the annual minimum billed amounts at the largest contract capacity value. The collateral requirement is due at the signing of the Electric Service Agreement. If Company becomes aware of an adverse change to Customer's or its guarantor's creditworthiness, Customer or its guarantor shall provide Company the increased collateral requirement due within three business days after written notice.

"Credit Rating" is Customer's or its guarantor's senior unsecured long-term debt rating (not supported by third-party credit enhancements) assigned by S&P and Moody's, or, if unavailable, Customer's or its guarantor's issuer credit rating assigned by S&P and Moody's.

"Letter of Credit" is an irrevocable, non-transferable, standby letter of credit issued by a Qualified Institution other than Customer or its guarantor or any affiliate of Customer or its guarantor in form and content reasonably acceptable to Company. All costs related to any Letter of Credit shall be borne by Customer.

"Qualified Institution" shall mean a major U.S. commercial bank or foreign bank with a U.S. branch office having an asset base of at least $10 billion, with such bank having a credit rating of at least "A-" by S&P and "A3" by Moody's.

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

Fluctuating Load Service Rate FLS

Rate:

Primary Service	**Current**	**Proposed**
Basic Service Charge per Day	$10.77	$16.23
Plus an Energy Charge per kWh	$0.03581	$0.03758
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$8.42	$9.18
Intermediate Demand Period	$6.69	$7.29
Base Demand Period	$2.93	$3.19
Transmission Service	**Current**	**Proposed**
Basic Service Charge per Day	$49.28	$74.28
Plus an Energy Charge per kWh	$0.03504	$0.03677
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$3.97	$4.33
Intermediate Demand Period	$2.94	$3.21

Base Demand Period	$1.49	$1.62

Lighting Service - Rate LS

Availability:

Current

Available under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of streets, 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, when the installation includes new underground-fed lights, when the installation includes three (3) or more overhead-fed lights, or when Customer requests conversion to LED.

Proposed

Available under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of streets, driveways, yards, lots, and other outdoor areas where secondary voltage of 120/240 is available.

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
Light Emitting Diode (LED)		
390 Cobra Head, 6K-8.2K Lumen Range Fixture Only	$ 9.86	$12.68
391 Cobra Head, 13K-16.5K Lumen Range Fixture Only	$11.99	$14.96
392 Cobra Head, 22K-29K Lumen Range Fixture Only	$15.51	$18.65
393 Open Bottom, 4.5K-6K Lumen Range Fixture Only	$ 8.14	$11.23
KC1 Cobra Head, 2.5K-4K Lumen Range Fixture Only	$ 8.63	$11.07
KC3 Cobra Head, 4K-6K Lumen Range Fixture Only	$ 9.17	$11.45
KF1 Directional, 4.5K-6K Lumen Range Fixture Only	$11.22	$14.27
KF2 Directional, 14K-17.5K Lumen Range Fixture Only	$13.26	$16.46
KF3 Directional, 22K-28K Lumen Range Fixture Only	$15.80	$19.29
KF4 Directional, 35K-50K Lumen Range Fixture Only	$22.86	$26.82
Wood Pole		
PK5 Wood Pole	$8.56	$9.29

	Rate Per Light Per Month	
UNDERGROUND SERVICE	**Current**	**Proposed**
Light Emitting Diode (LED)		
KC2 Cobra Head, 2.5K-4K Lumen Range Fixture Only	$ 4.53	$4.80
KC4 Cobra Head, 4K-6K Lumen Range Fixture Only	$ 5.04	$5.18
396 Cobra Head, 5.5K-8.2K Lumen Range Fixture Only	$ 5.75	$6.40
397 Cobra Head, 13K-16.5K Lumen Range Fixture Only	$ 7.88	$8.68
398 Cobra Head, 22K-29K Lumen Range Fixture Only	$11.40	$12.37
399 Colonial, 4-Sided, 4K-7K Lumen Range Fixture Only	$ 7.40	$8.41
KA1 Acorn, 4K-7K Lumen Range Fixture Only	$ 9.09	$9.91
KN1 Contemporary, 4K-7K Lumen Range Fixture Only	$ 7.15	$8.14
KN2 Contemporary, 8K-11K Lumen Range Fixture Only	$ 8.65	$9.71
KN3 Contemporary, 13.5K-16.5K Lumen Range Fixture Only	$10.66	$11.77
KN4 Contemporary, 21K-28K Lumen Range Fixture Only	$15.39	$17.26
KN5 Contemporary, 45K-50K Lumen Range Fixture Only	$21.42	$23.03

KF5 Directional, 4.5K-6K Lumen Range Fixture Only	$ 8.67	$9.60
KF6 Directional, 14K-17.5K Lumen Range Fixture Only	$10.71	$11.79
KF7 Directional, 22K-28K Lumen Range Fixture Only	$13.25	$14.62
KF8 Directional, 35K-50K Lumen Range Fixture Only	$20.31	$22.14
KV1 Victorian, 4K-7K Lumen Range Fixture Only	$21.45	$22.36
Pole Charges		
PK1 Cobra	$12.62	$19.30
PK2 Contemporary	$11.69	$17.62
PK3 Post-Top – Decorative Smooth	$8.73	$12.04
PK4 Post-Top – Historic Fluted	$14.47	$17.03

Conversion Fee

Current

Customer will be required to pay a monthly conversion fee for 60 months if Customer requests to change current functioning non-LED fixture to an LED fixture. This conversion fee represents the remaining book value of the current working non-LED fixture.

One-Time Conversion Fee $197.16
Monthly Conversion Fee: $3.29 per month for 60 months

Proposed

Customer must choose to pay either a one-time conversion fee or a monthly conversion fee for 60 months if Customer requests to change current functioning non-LED fixture to an LED fixture.

One-Time Conversion Fee $197.16
Monthly Conversion Fee: $3.29 per month for 60 months

Term of Contract

Current

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 (5) 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.

Proposed

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, when the installation includes new underground-fed lights, when the installation includes three (3) or more overhead-fed lights, or when Customer requests conversion to LED. Cancellation by Customer prior to the initial five (5) 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.

Service will be provided under written contract, signed by Customer prior to service commencing, when additional facilities are required, when the installation includes new underground-fed lights, when the installation includes three (3) or more overhead-fed lights, or when Customer requests conversion to LED.

Terms and Conditions:

Current

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities, Customer agrees to pay to Company its cost of labor to remove

existing facilities. Customer will be required to pay Conversion Fee if Customer requests installation of LED replacement within five (5) years.

Proposed

6. If Customer requests the removal of an existing Restricted Lighting Service (RLS) lighting system, Customer will be required to pay Conversion Fee if Customer requests installation of LED replacement within five (5) years of the removal.

Restricted Lighting Service – Rate RLS

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
High-Pressure Sodium		
461 Cobra Head, 4000 Lumen Fixture Only	$10.01	$10.86
471 Cobra Head, 4000 Lumen Fixture & Pole	$13.52	$14.66
462 Cobra Head, 5800 Lumen Fixture Only	$11.31	$12.27
472 Cobra Head, 5800 Lumen Fixture & Pole	$15.19	$16.47
463 Cobra Head, 9500 Lumen Fixture Only	$11.57	$12.55
473 Cobra Head, 9500 Lumen Fixture & Pole	$15.68	$17.00
464 Cobra Head, 22000 Lumen Fixture Only	$18.09	$19.62
474 Cobra Head, 22000 Lumen Fixture & Pole	$22.49	$24.39
465 Cobra Head, 50000 Lumen Fixture Only	$28.46	$30.86
475 Cobra Head, 50000 Lumen Fixture & Pole	$31.40	$34.05
409 Cobra Head, 50000 Lumen Fixture Only	$16.26	$17.63
426 Open Bottom, 5800 Lumen Fixture Only	$9.91	$10.75
428 Open Bottom, 9500 Lumen Fixture Only	$10.02	$10.87
487 Directional, 9500 Lumen Fixture Only	$11.41	$12.37
488 Directional, 22000 Lumen Fixture Only	$17.41	$18.88
489 Directional, 50000 Lumen Fixture Only	$24.59	$26.67
Metal Halide		
450 Directional, 12000 Lumen Fixture Only	$18.26	$19.80
454 Directional, 12000 Lumen Fixture & Pole	$23.29	$25.26
455 Directional, 32000 Lumen Fixture & Pole	$30.62	$33.21
452 Directional, 107800 Lumen Fixture Only	$53.27	$57.77
459 Directional, 107800 Lumen Fixture & Pole	$58.30	$63.23
451 Directional, 32000 Lumen Fixture Only	$25.59	$27.75
Mercury Vapor		
446 Cobra Head 7000L Fixture Only	$12.49	$13.55
456 Cobra Head 7000L Fixture & Pole	$14.79	$16.04
447 Cobra Head 10000 Lumen Fixture Only	$14.79	$16.04
457 Cobra Head 10000 Lumen Fixture & Pole	$16.74	$18.15
448 Cobra Head 20000 Lumen Fixture Only	$16.31	$17.69
458 Cobra Head 20000 Lumen Fixture & Pole	$18.92	$20.52
404 Open Bottom 7000 Lumen Fixture Only	$13.23	$14.35
Incandescent		
421 Tear Drop, 1000 Lumen Fixture Only	$4.29	$4.65
422 Tear Drop, 2500 Lumen Fixture Only	$5.67	$6.15
424 Tear Drop, 4000 Lumen Fixture Only	$8.69	$9.42
425 Tear Drop, 6000 Lumen Fixture Only	$11.33	$12.29

Rate Per Light Per Month

UNDERGROUND SERVICE	**Current**	**Proposed**
Metal Halide		
460 Directional, 12000 Lumen Fixture & Pole	$34.23	$37.12
469 Directional, 32000 Lumen Fixture & Pole	$40.60	$44.03
470 Directional, 107800 Lumen Fixture & Pole	$68.03	$73.78
490 Contemporary, 12000 Lumen Fixture Only	$19.66	$21.32
491 Contemporary, 32000 Lumen Fixture Only	$27.57	$29.90
493 Contemporary, 107800 Lumen Fixture Only	$57.11	$61.94
494 Contemporary, 12000 Lumen Fixture & Pole	$34.43	$37.34
495 Contemporary, 32000 Lumen Fixture & Pole	$42.57	$46.17
496 Contemporary, 107800 Lumen Fixture & Pole	$71.87	$77.94
High Pressure Sodium		
440 Acorn, 4000 Lumen Fixture & Smooth Pole	$17.75	$19.25
410 Acorn, 4000 Lumen Fixture & Fluted Pole	$25.12	$27.24
401 Acorn, 5800 Lumen Fixture & Smooth Pole	$19.05	$20.66
411 Acorn, 5800 Lumen Fixture & Fluted Pole	$26.81	$29.08
420 Acorn, 9500 Lumen Fixture & Smooth Pole	$19.30	$20.93
430 Acorn, 9500 Lumen Fixture & Fluted Pole	$27.19	$29.49
466 Colonial, 4-Sided 4000 Lumen Fixture & Smooth Pole	$12.48	$13.53
412 Coach, 5800 Lumen Fixture & Smooth Pole	$36.91	$40.03
413 Coach, 9500 Lumen Fixture & Smooth Pole	$37.01	$40.14
467 Colonial, 4-Sided 5800 Lumen Fixture & Smooth Pole	$14.21	$15.41
468 Colonial, 4-Sided 9500 Lumen Fixture & Smooth Pole	$14.31	$15.52
492 Contemporary, 5800 Lumen Fixture Only	$18.98	$20.58
476 Contemporary, 5800 Lumen Fixture & Contemporary Pole	$21.35	$23.15
497 Contemporary, 9500 Lumen Fixture Only	$18.61	$20.18
477 Contemporary, 9500 Lumen Fixture & Contemporary Pole	$25.96	$28.15
498 Contemporary, 22000 Lumen Fixture Only	$22.08	$23.95
478 Contemporary, 22000 Lumen Fixture & Contemporary Pole	$33.71	$36.56
499 Contemporary, 50000 Lumen Fixture Only	$26.92	$29.19
479 Contemporary, 50000 Lumen Fixture & Contemporary Pole	$41.69	$45.21
300 Dark Sky, 4000 Lumen Fixture & Smooth Pole	$26.99	Removed
301 Dark Sky, 9500 Lumen Fixture & Smooth Pole	$28.15	Removed
414 Victorian, 5800 Lumen Fixture Only	$36.92	$40.04
415 Victorian, 9500 Lumen Fixture Only	$37.00	$40.13

Lighting Energy Service - Rate LE

Rate:

	Current	**Proposed**
Energy Charge per kWh:	$0.07854	$0.08743

Traffic Energy Service – Rate TE

Availability:

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 devices including, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, emergency sirens, and gunshot triangulation 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 available for devices including, but not limited to, vehicle and pedestrian signals and traffic lights, sirens, cameras, sensors, electronic communication devices, and gunshot triangulation devices.

Rate:

	Current	Proposed
Basic Service Charge per Day:	$0.13 per delivery point	$0.14 per delivery point
Energy Charge per kWh:	$0.09524	$0.10622

Conditions of Service

Current

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

Proposed

3. Customer shall reimburse Company for all installation and removal costs.

Pole and Structure Attachment Charges, Terms and Conditions – Rate PSA

Attachment Charges:

Current	Proposed	
$7.25	Removed	per year for each wireline pole attachment
New	$10.13	per year for each two-user wireline pole attachment
New	$10.46	per year for each three-user wireline pole attachment
$0.81	$1.22	per year for each linear foot of duct.
$36.25	$51.46	per year for each Wireless Facility located on the top of a Company pole.

Electric Vehicle Supply Equipment – Rate EVSE

Availability

Current

Available to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, and FLS, for the purpose of charging electric vehicles.

Proposed

Available to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, EHLF, and FLS, for the purpose of charging electric vehicles.

Rate:

	Current	Proposed
Monthly Charging Unit Fee:		
Networked Charger (Option A):		
Single Charger	$132.09	$191.81
Dual Charger	$193.62	$330.34
Networked Charger (Option B):		
Single Charger	New	$161.21

Dual Charger	New	$254.60
Non-Networked Charger:		
Single Charger:	$80.14	$85.01

New – Charging Station Descriptions
Networked Charger (Option A): Networked charging station with dashboard and availability capabilities. Suitable for all use cases, particularly public installation, and high-traffic locations. For installations that require access control, remote monitoring, usage data collection, automatic cord retraction, and dual logo branding.

Networked Charger (Option B): Networked charging station with dashboard and availability capabilities. Suitable for all use cases, particularly public installation, and high-traffic locations. For installations that require access control, remote monitoring, and usage data collection.

Non-Networked Charger: Basic non-networked EV charging station. Suitable for less public use cases, and particularly good for workplaces, fleets, and low-traffic retail.

Energy Consumption:
Current
Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 5,004 kilowatt-hours.
Proposed
Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 8,203 kilowatt-hours.

Terms and Conditions:
Current
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.
Proposed
7. Temporary suspension of charging station is only permitted if Company and Customer mutually agree to the temporary suspension. 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.

New – Electric Vehicle Charging Service (EVC)
The Electric Vehicle Charging Service – Level 2 (EVC-L2) and Electric Vehicle Charging Service – FAST (EVC-FAST) rate schedules were combined into one single rate schedule, Electric Vehicle Charging Service (EVC).

Availability:
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 Company's fee structure for the vehicle charging service. EVC-L2 is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas for stations rated at AC Level 2 speeds. EVC-FAST is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas using chargers with an output of 50 kW or greater. EV Customers' charging systems must meet applicable

charging standards. Service under this rate schedule is limited to a maximum of ten stations. Company will accept Customers on a first-come-first-served basis.

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

Rate:

	Current	Proposed
EVC-L2 Fee for Use:	New	$0.25 per kWh
EVC-FAST Fee for Use:	$0.25 per kWh	$0.25 per kWh

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
Retired Asset Recovery	Sheet No. 89
Renewable Power Purchase Agreement Adjustment Clause	Sheet No. 90

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

Franchise Fee	Sheet No. 91
School Tax	Sheet No. 92

Terms and Conditions

1. Service shall be furnished under the following Terms and Conditions and excludes 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. Also, Company shall not be liable for any loss, injury, or damage resulting from interruption, reduction, delay, or failure of electric service except where Company's willful misconduct is the sole and proximate cause of said loss, injury or damage.

4. Company is merely a supplier of electricity delivered to the point of connection of Company's 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 except where Company's negligence or willful misconduct is the sole and proximate cause of said injury or damage.

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.

Outdoor Sports Lighting Service (OSL)

Rate OSL moved from a pilot rate to a standard rate.

Availability:

Current

Available as an optional pilot program for secondary and primary service used by a Customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty Customers. Company will accept Customers on a first-come-first-served basis.

Proposed

Available as an optional program for secondary and primary service used by a Customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty Customers. Company will accept Customers on a first-come-first-served basis.

Rate:

Secondary	**Current**	**Proposed**
Basic Service Charge per day	$2.96	$3.40
Plus and Energy Charge per kWh of:	$0.03372	$0.03877
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$21.55	$20.84
Base Demand Period	$2.93	$2.83
Primary	**Current**	**Proposed**
Basic Service Charge per day	$7.89	$7.89
Plus and Energy Charge per kWh of:	$0.03026	$0.03782
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$17.16	$16.60
Base Demand Period	$2.51	$2.43

Change to Adjustment Clauses Section of Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, FLS, LS, RLS, LE, TE, EVSE, and OSL

The Company proposes to add Retired Asset Recovery (Sheet No. 89) and the proposed Renewable Power Purchase Agreement Adjustment Clause (Sheet No. 90) to the Adjustment Clauses section of Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, FLS, LS, RLS, LE, TE, EVSE, and OSL. The Company further proposes to renumber: Franchise Fee, currently Sheet No. 90, to be Sheet No. 91; School Tax, currently Sheet No. 91, to be Sheet No. 92; and Home

Energy Assistance Program, currently Sheet No. 92, to be Sheet No. 93.

Special Charges

Returned Payment Charge

Current Rate	$ 3.50	**Proposed Rate**	$3.00

Meter Test Charge

Current Rate	$79.00	**Proposed Rate**	$89.00

Disconnecting and Reconnecting Service Charge

Without "Remote Disconnection and Reconnection"

Current Rate	$37.00	**Proposed Rate**	$87.00

With "Remote Disconnection and Reconnection"

Current Rate	$0	**Proposed Rate**	$0

Meter Pulse Charge

Current Rate $21.00
Proposed Rate $24.00

Unauthorized Connection Charge:

Current

When 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 $45.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $66.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
3. A charge of $87.00 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 $149.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Infrastructure (AMI) meter; or
5. A charge of $154.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

Proposed

When 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 $57.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $78.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
3. A charge of $99.00 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 $151.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering Infrastructure (AMI) meter; or
5. A charge of $167.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

6. A charge of $256.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase AMI meter.

AMI Opt-Out Charges

Current

Customer may opt out of having an AMI meter by contacting Company to request a non-AMI meter. If Company has a non-AMI meter available, Company will honor Customer's opt-out request and assess the following charges:

1. A one-time opt-out set-up fee of $39.00 per service delivery point. During Company's AMI project deployment phase, if Customer requests a non-AMI meter prior to an AMI meter being installed at Customer's premise, Company will not charge the one-time set-up fee.
2. A monthly opt-out charge of $15.00 per service delivery point.

If Customer chooses to opt out any meter on a single premise, Customer must opt out all Company meters and modules (electric and gas) on that premise. Company has sole discretion to determine the alternative metering to be used for opted-out meters and modules.

Proposed

Customer may opt out of having an AMI meter by contacting Company to request a non-AMI meter. If Company has a non-AMI meter available, Company will honor Customer's opt-out request and assess the following charges:

1. A one-time opt-out set-up fee of $74.00 per service delivery point. During Company's AMI project deployment phase, if Customer requests a non-AMI meter prior to an AMI meter being installed at Customer's premise, Company will not charge the one-time set-up fee.
2. A monthly opt-out charge of $24.00 per service delivery point.

If Customer chooses to opt out any meter on a single premise, Customer must opt out all Company meters and modules (electric and gas) on that premise. Company has sole discretion to determine the alternative metering to be used for opted-out meters and modules.

Company will treat Customer's refusal to make suitable provision for Company's AMI meter as Customer's choice to opt out of having an AMI meter. Such refusal includes without limitation Customer's refusal to make safe and stable a customer-owned pole to which Company's existing meter is attached.

Curtailable Service Rider-1 – CSR-1

Curtailable Billing Demand:

Current

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) 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 Customer Designated Curtailable Load, as described above.

Proposed

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) 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, weekdays from 10 AM to 10 PM (EST) and (ii) for the months October through April, weekdays from 6 AM to 10 PM (EST) and (b) the firm contract demand.

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

Curtailable Service Rider-2 – CSR-2

Curtailable Billing Demand:

Current

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) 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.

Proposed

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) 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, weekdays from 10 AM to 10 PM (EST) and (ii) for the months October through April, weekdays from 6 A.M. to 10 PM (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.

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

Rates:

	Current	Proposed
SQF/LQF Solar: Single-Axis Tracking; Distribution; 2-Year PPA; Energy	$30.43	$33.02
SQF/LQF Solar: Single-Axis Tracking; Distribution; 7-Year PPA; Energy	$32.16	$38.50
SQF/LQF Solar: Single-Axis Tracking; Transmission; 2-Year PPA; Energy	$29.05	$31.52
SQF/LQF Solar: Single-Axis Tracking; Transmission; 7-Year PPA; Energy	$30.71	$36.75
SQF/LQF Solar: Fixed Tilt; Distribution; 2-Year PPA; Energy	$30.73	$33.05
SQF/LQF Solar: Fixed Tilt; Distribution; 7-Year PPA; Energy	$32.56	$38.59
SQF/LQF Solar: Fixed Tilt; Transmission; 2-Year PPA; Energy	$29.33	$31.55
SQF/LQF Solar: Fixed Tilt; Transmission; 7-Year PPA; Energy	$31.09	$36.84
SQF/LQF Wind; Distribution; 2-Year PPA; Energy	$29.27	$32.07
SQF/LQF Wind; Distribution; 7-Year PPA; Energy	$31.55	$36.59
SQF/LQF Wind; Transmission; 2-Year PPA; Energy	$27.94	$30.62
SQF/LQF Wind; Transmission; 7-Year PPA; Energy	$30.12	$34.93
SQF/LQF Other Technologies; Distribution; 2-Year PPA; Energy	$29.39	$31.99

SQF/LQF Other Technologies; Distribution; 7-Year PPA; Energy	$31.96	$37.06
SQF/LQF Other Technologies; Transmission; 2-Year PPA; Energy	$28.05	$30.54
SQF/LQF Other Technologies; Transmission; 7-Year PPA; Energy	$30.51	$35.38
SQF/LQF Solar: Single-Axis Tracking; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Single-Axis Tracking; Distribution; 7-Year PPA; Capacity	$12.81	$0
SQF/LQF Solar: Single-Axis Tracking; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Single-Axis Tracking; Transmission; 7-Year PPA; Capacity	$12.03	$0
SQF/LQF Solar: Fixed Tilt; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Fixed Tilt; Distribution; 7-Year PPA; Capacity	$15.42	$0
SQF/LQF Solar: Fixed Tilt; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Fixed Tilt; Transmission; 7-Year PPA; Capacity	$14.49	$0
SQF/LQF Wind; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Wind; Distribution; 7-Year PPA; Capacity	$10.10	$0
SQF/LQF Wind; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Wind; Transmission; 7-Year PPA; Capacity	$9.49	$0
SQF/LQF Other Technologies; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Other Technologies; Distribution; 7-Year PPA; Capacity	$8.93	$18.94
SQF/LQF Other Technologies; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Other Technologies; Transmission; 7-Year PPA; Capacity	$8.39	$17.80

Availability:

Current

This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy or energy and capacity from the owner of a “qualifying facility” as defined in 807 KAR 5:054 Section 1(8) (such owner being hereafter called “Seller”) with a nameplate capacity of 100 kW or less .

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 or energy and capacity from Seller at the rates, set out below and under the terms and conditions stated herein.

Seller may choose to (a) enter into a power purchase agreement (“PPA”) with Company for sales of energy or energy and capacity from Seller or (b) sell energy to Company on an as-available basis.

Proposed

This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy or energy and capacity from the owner of a “qualifying facility” as defined in 807 KAR 5:054 Section 1(8) (such owner being hereafter called “Seller”) with a nameplate capacity of 100 kW or less .

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 or energy and capacity from Seller at the rates set out below and under the terms and conditions stated herein.

Seller may choose either (a) to enter into a power purchase agreement ("PPA") with Company for sales of energy and capacity from Seller or (b) to sell only energy to Company on an as-available basis. Seller may enter into a PPA with Company only if Seller simultaneously sells the entire output of Seller's qualifying facility to Company while purchasing all of Seller's own requirements from Company.

Term of Contract:

Current

If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 7-year PPA with Company for such purchases. Regarding energy purchases under a 7-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 7-year level energy rate or (b) the applicable as-available energy rate in effect at the time of each purchase.

Proposed

If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 7-year PPA with Company for such purchases. Rates offered under all PPAs will be based at Seller's option on either applicable Rider SQF rates at the time of delivery or applicable Rider SQF rates at the time the PPA is executed.

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

Rates:

	Current	Proposed
SQF/LQF Solar: Single-Axis Tracking; Distribution; 2-Year PPA; Energy	$30.43	$33.02
SQF/LQF Solar: Single-Axis Tracking; Distribution; 7-Year PPA; Energy	$32.16	$38.50
SQF/LQF Solar: Single-Axis Tracking; Transmission; 2-Year PPA; Energy	$29.05	$31.52
SQF/LQF Solar: Single-Axis Tracking; Transmission; 7-Year PPA; Energy	$30.71	$36.75
SQF/LQF Solar: Fixed Tilt; Distribution; 2-Year PPA; Energy	$30.73	$33.05
SQF/LQF Solar: Fixed Tilt; Distribution; 7-Year PPA; Energy	$32.56	$38.59
SQF/LQF Solar: Fixed Tilt; Transmission; 2-Year PPA; Energy	$29.33	$31.55
SQF/LQF Solar: Fixed Tilt; Transmission; 7-Year PPA; Energy	$31.09	$36.84
SQF/LQF Wind; Distribution; 2-Year PPA; Energy	$29.27	$32.07
SQF/LQF Wind; Distribution; 7-Year PPA; Energy	$31.55	$36.59
SQF/LQF Wind; Transmission; 2-Year PPA; Energy	$27.94	$30.62
SQF/LQF Wind; Transmission; 7-Year PPA; Energy	$30.12	$34.93
SQF/LQF Other Technologies; Distribution; 2-Year PPA; Energy	$29.39	$31.99
SQF/LQF Other Technologies; Distribution; 7-Year PPA; Energy	$31.96	$37.06
SQF/LQF Other Technologies; Transmission; 2-Year PPA; Energy	$28.05	$30.54
SQF/LQF Other Technologies; Transmission; 7-Year PPA; Energy	$30.51	$35.38
SQF/LQF Solar: Single-Axis Tracking; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Single-Axis Tracking; Distribution; 7-Year PPA; Capacity	$12.81	$0
SQF/LQF Solar: Single-Axis Tracking; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Single-Axis Tracking; Transmission; 7-Year PPA;	$12.03	$0

Capacity		
SQF/LQF Solar: Fixed Tilt; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Fixed Tilt; Distribution; 7-Year PPA; Capacity	$15.42	$0
SQF/LQF Solar: Fixed Tilt; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Solar: Fixed Tilt; Transmission; 7-Year PPA; Capacity	$14.49	$0
SQF/LQF Wind; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Wind; Distribution; 7-Year PPA; Capacity	$10.10	$0
SQF/LQF Wind; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Wind; Transmission; 7-Year PPA; Capacity	$9.49	$0
SQF/LQF Other Technologies; Distribution; 2-Year PPA; Capacity	$0	$0
SQF/LQF Other Technologies; Distribution; 7-Year PPA; Capacity	$8.93	$18.94
SQF/LQF Other Technologies; Transmission; 2-Year PPA; Capacity	$0	$0
SQF/LQF Other Technologies; Transmission; 7-Year PPA; Capacity	$8.39	$17.80

Availability:
Current
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy or energy and capacity from the owner of a “qualifying facility” as defined in 807 KAR 5:054 Section 1(8) (such owner being hereafter called “Seller”) with a nameplate capacity of 100 kW or less .

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 or energy and capacity from Seller at the rates, set out below and under the terms and conditions stated herein.

Seller may choose to (a) enter into a power purchase agreement (“PPA”) with Company for sales of energy or energy and capacity from Seller or (b) sell energy to Company on an as-available basis.
Proposed
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy or energy and capacity from the owner of a “qualifying facility” as defined in 807 KAR 5:054 Section 1(8) (such owner being hereafter called “Seller”) with a nameplate capacity of 100 kW or less .

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 or energy and capacity from Seller at the rates set out below and under the terms and conditions stated herein.

Seller may choose either (a) to enter into a power purchase agreement (“PPA”) with Company for sales of energy and capacity from Seller or (b) to sell only energy to Company on an as-available basis. Seller may enter into a PPA with Company only if Seller simultaneously sells the entire output of Seller’s qualifying facility to Company while purchasing all of Seller’s own requirements from Company.

Term of Contract:
Current
If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 7-year PPA with Company for such purchases. Regarding energy purchases under a 7-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 7-year level energy rate

or (b) the applicable as-available energy rate in effect at the time of each purchase.

Proposed

If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 7-year PPA with Company for such purchases. Rates offered under all PPAs will be based at Seller's option on either applicable Rider LQF rates at the time of delivery or applicable Rider LQF rates at the time the PPA is executed.

Net Metering Service-2 – Rider NMS-2

Availability:

Current

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 whose eligible generating facility first attains in service status on or after September 24, 2021. The generation facility shall be limited to a maximum rated capacity of 45 kilowatts.

Each Customer-generator taking service under NMS-2 and a standard rate schedule with a two-part rate structure will be allowed to take service under a two-part rate structure for 25 years from the date on which the Customer-generator began taking service under NMS-2.

Proposed

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 whose eligible generating facility first attains in service status on or after September 24, 2021. The generation facility shall be limited to a maximum rated capacity of 45 kilowatts.

Each Customer-generator taking service under NMS-2 and a standard rate schedule with a two-part rate structure will be allowed to take service under a two-part rate structure for 25 years from the date on which the Customer-generator began taking service under NMS-2.

Consistent with KRS 278.466(1), Company will cease offering service under Rider NMS-2 to any new Customer-generator after: (A) the cumulative generating capacity of NMS-1 and NMS-2 Customer-generators reaches a combined one percent (1%) of Company's single hour peak load during a calendar year; and (B) Company receives Commission approval to do so.

Rate:

Current

Dollar-denominated bill credit:	$0.07534 per kWh

Proposed

Dollar-denominated bill credit:	$0.03859 per kWh

Standard Rider for Excess Facilities – Rider EF

Rate:

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	1.14%	1.27 %

(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	0.46%	0.51 %

Standard Rider for Redundant Capacity Charge – Rider RC

Rate:

Capacity Reservation Charge per Month:	**Current (Per kW/kVA)**	**Proposed (Per kW/kVA)**
Secondary Distribution	$1.33	$2.26
Primary Distribution	$0.90	$1.65

Solar Share Program Rider – Rider SSP

Availability:

Current

This optional, voluntary service is available to Customers taking service under Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, GTOD-Energy, GTOD-Demand, AES, PS, TODS, and TODP. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

Proposed

This optional, voluntary service is available to Customers taking service under Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, and EHLF. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

Rate:

Solar Capacity Charge	**Current Per quarter-kW Subscribed**	**Proposed Per quarter-kW Subscribed**
One-Time Solar Capacity Charge	$799.00	$799.00
Monthly Solar Capacity Charge	$5.55	$5.55

Program Description:

Current

The Solar Share Program is an optional, voluntary program that allows customers to subscribe to 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.

There are two mutually exclusive options for subscribing to each increment of capacity.

Option 1: Capacity Subscribed by Paying Only the One-Time Solar Capacity Charge

For capacity subscribed by paying the One-Time Solar Capacity Charge, the One-Time Solar Capacity Charge will be included on the Subscriber's bill for the first billing period in which the subscribed capacity achieves commercial operation.

A customer choosing to pay the One-Time Solar Capacity Charge may transfer subscribed capacity between the customer's own accounts or may assign subscribed capacity to another customer. Once assigned, the assigning customer forfeits all rights to the assigned capacity.

A customer who ceases taking service from Company will have 60 calendar days to assign subscribed capacity to another customer within Company's service area. Any capacity such a customer does not assign within 60 days of ceasing to take service will be forfeited and made available to other customers under Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge.

Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge

For capacity subscribed by paying the Monthly Solar Capacity Charge, the Solar Capacity Charge will be included on the Subscriber's bill beginning with the bill for the first billing period in which the subscribed capacity achieves commercial operation.

Monthly subscriptions of less than 50 kW DC will not require a contract; however, a customer may not reduce or cancel a monthly subscription earlier than 12 months from the date of the customer's most recent change to the customer's monthly subscription level. Therefore, a customer subscribing monthly less than 50 kW has a 12-month commitment from the date of the customer's initial monthly subscription or initial solar facility commercial operation, whichever is later, and may have a longer commitment if the customer subsequently increases monthly subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the monthly subscription after the initial 12 months. Monthly subscriptions of 50 kW DC or more require a 5-year contract with Company.

Proposed

The Solar Share Program is an optional, voluntary program that allows customers to subscribe to 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.

There are two mutually exclusive options for subscribing to each increment of capacity.

Option 1: Capacity Subscribed by Paying Only the One-Time Solar Capacity Charge

For capacity subscribed by paying the One-Time Solar Capacity Charge, the One-Time Solar Capacity Charge will be included on the Subscriber's bill for the first billing period in which the subscribed capacity becomes available.

A customer choosing to pay the One-Time Solar Capacity Charge may transfer subscribed capacity between the customer's own accounts or may assign subscribed capacity to another customer. Once assigned, the assigning customer forfeits all rights to the assigned capacity.

A customer who ceases taking service from Company will have 30 calendar days to assign subscribed capacity to another customer within Company's service area. Any capacity such a customer does not assign within 30 days of ceasing to take service will be forfeited and made available to other customers.

Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge

For capacity subscribed by paying the Monthly Solar Capacity Charge, the Solar Capacity Charge will be included on the Subscriber's bill beginning with the bill for the first billing period in which the subscribed capacity becomes available.

Monthly subscriptions of less than 50 kW DC will not require a contract; however, a customer may not reduce or cancel a monthly subscription earlier than 12 months from the date of the customer's most recent change to the customer's monthly subscription level. Therefore, a customer subscribing monthly less than 50 kW has a 12-month commitment from the date of the customer's initial monthly subscription Customer may have a longer commitment if the customer subsequently increases monthly subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the monthly subscription after the initial 12 months. Monthly subscriptions of 50 kW DC or more require a 5-year contract with Company.

Terms and Conditions:
<u>Current</u>
2. Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC (nominal). No customer may subscribe more than 250 kW DC (nominal) in any single Solar Share Facility.
<u>Proposed</u>
Removed

<u>Electric Vehicle Supply Equipment – Rider EVSE-R</u>

Availability:
<u>Current</u>
Available as a rider to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles, whereby 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. Company will furnish, own, and maintain the charging unit and cable. The customer will own and maintain duct systems and associated equipment needed to serve the charger.

Company may coordinate charging station installation with Company's current charging station supplier and 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.
<u>Proposed</u>
Available as a rider to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), GTOD-Energy, GTOD-Demand, AES, PS, TODS, TODP, RTS, EHLF, and FLS, for the purpose of charging electrical vehicles, whereby 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. Company will furnish, own, and maintain the charging unit and cable. The customer will own and maintain duct systems and associated equipment needed to serve the charger.

Company may coordinate charging station installation with Company's current charging station contractor and 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.

Monthly Charging Unit Fee	**Current**	**Proposed**
Networked Charger (Option A):		
Single Charger	$121.79	$144.03
Dual Charger	$173.02	$234.79
Networked Charger (Option B):		
Single Charger	New	$113.44
Dual Charger	New	$159.05
Non-Networked Charger:		
Single Charger	$30.58	$37.24

NEW - Charging Stations Descriptions:
Networked Charger (Option A): Networked charging station with dashboard and availability capabilities. Suitable for all use cases, particularly public installation, and high-traffic locations. For installations that require access control, remote monitoring, usage data collection, automatic cord retraction, and dual logo branding.

Networked Charger (Option B): Networked charging station with dashboard and availability capabilities. Suitable for all use cases, particularly public installation, and high-traffic locations. For installations that require access control, remote monitoring, and usage data collection.

Non-Networked Charger: Basic non-networked EV charging station. Suitable for less public use cases, and particularly good for workplaces, fleets, and low-traffic retail.

Terms and Conditions:
Current
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.
Proposed
7.Temporary suspension of charging station is only permitted if Company and Customer mutually agree to the temporary suspension. 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.

Demand-Side Management Cost Recovery Mechanism (DSM)

Residential Online Audit:
Current
This program will not begin until January 1, 2025.

This program is a web-based, self-guided assessment of a customer's home and includes information about the home's space and water heating, appliance and plug load, and other energy end uses. The audit pulls customer-specific interval data from the Company's AMI to provide an accurate picture of the customer's disaggregated energy use. After completing the online audit, customers receive feedback on their energy-use behavior, energy-saving tips, and recommendations and are mailed a kit with energy efficiency measures for self-installation. The kit will include a low-flow bathroom faucet aerator, a low-flow kitchen faucet aerator, a low-flow showerhead, water heater pipe insulation, weatherstripping, caulking, spray foam, and an advanced power strip. In addition, customers who complete the audit gain access to prescriptive rebates for deeper energy efficiency retrofits. Rebate examples include: heat pump water heaters ($300), central air conditioner ($300), ductless heat pump ($400), air source heat pump ($400), and 95% AFUE furnace ($250).

Proposed

This program is a web-based, self-guided assessment of a customer's home and includes information about the home's space and water heating, appliance and plug load, and other energy end uses. The audit pulls customer-specific interval data from the Company's AMI to provide an accurate picture of the customer's disaggregated energy use. After completing the online audit, customers receive feedback on their energy-use behavior, energy-saving tips, and recommendations and are mailed a kit with energy efficiency measures for self-installation. The kit may include a low-flow bathroom faucet aerator, a low-flow kitchen faucet aerator, a low-flow showerhead, water heater pipe insulation, weatherstripping, caulking, spray foam, and an advanced power strip. In addition, customers gain access to prescriptive rebates for deeper energy efficiency retrofits. Rebate examples include: heat pump water heaters, central air conditioner, ductless heat pump, and air source heat pump.

Small Business Audit and Direct Install:

Current

This program provides free energy audits to small businesses and allows for direct installation of high-efficiency equipment. A third-party contractor will provide a complimentary energy audit of the customer's facility. The Company will provide free direct installation of energy-saving products that may include nonresidential LED bulbs and fixtures, faucet aerators, low-flow showerheads, and pre-rinse spray valves.

Proposed

This program provides free energy audits, energy education, and installation of energy conservation measures to small businesses.

Non-Residential Demand Response:

Current

This program may employ (as needed) interfaces to customer equipment to help reduce the demand for electricity during peak times. The program communicates with the interfaces to cycle equipment. This program has an approved flexible incentive structure. The Company will notify customers in advance of peak demand events. The incentive rate is up to $75 per kW curtailed. The incentive amount that a participant receives will continue to be calculated based on the actual demand reduction achieved by the participant over the entire year's events.

Qualifying Rate Schedules: AES, PS, TODS, TODP, RTS, and FLS customers with at least a 200 kW demand and a minimum load reduction capability of at least 50 kW. Curtailable Service Rider (CSR) customers are not eligible for participation in this program.

Proposed

This program may employ (as needed) interfaces to customer equipment to help reduce the demand for electricity during peak times. The program communicates with the interfaces to cycle equipment. This program has an approved flexible incentive structure. The Company will notify customers in advance of peak demand events. The incentive rate is up to $75 per kW-year curtailed. The incentive amount that a participant receives will continue to be calculated based on the actual demand reduction achieved by the participant over the entire contract year's events.

Qualifying Rate Schedules: GS customers with twelve (12) month-average maximum monthly loads exceeding 50 kW who were receiving service under P.S.C. No. 13, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, and chose to continue being served under Rate GS, AES, PS, TODS, TODP, RTS, EHLF, and FLS customers with at least a 200 kW demand and a minimum load reduction capability of at least 50 kW. Curtailable Service Rider (CSR) customers are not eligible for participation in this program.

Environmental Cost Recovery Surcharge

Availability of Service:

Current

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including OSS) and DSM Adjustment Clauses. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

Proposed

This schedule is mandatory to Standard Rate Schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and Adjustment Clauses (Fuel Adjustment Clause (including Off-System Sales Adjustment Clause), Demand-Side Management Cost Recovery Mechanism, Retired Asset Recovery, and Renewable Power Purchase Agreement Adjustment Clause). Rate schedules subject to the ECR adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; EHLF; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

Other

The Company proposes to apply the approved return on equity in this proceeding to Adjustment Clause ECR beginning with the January 2026 expense month.

Retired Asset Recovery Adjustment Clause - RAR

Current

AVAILABILITY OF SERVICE

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges and all Pilot Programs listed in Section 3 of the General Index. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.

Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

RATE

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

Group RAR 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 retirement-related regulatory asset revenue requirement for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month.

DEFINITIONS

1. Retirement Assets are the regulatory assets and associated ADIT created after the date of the Commission's Final Order in Case No. 2020-00350 for the Retirement Costs of generating assets retired and other site-related assets that will not continue in use.

2. Retirement Costs include the net book value, materials and supplies that cannot be used economically at other plants owned by Company, and removal costs and salvage credits, net of related accumulated deferred income tax ("ADIT"). Related ADIT shall include the tax benefits from tax losses.
3. For each Retirement Asset, E(m) is the monthly levelized expense required to amortize the Retirement Asset over a 10-year amortization period beginning with the month in which the Retirement Asset is created. E(m) includes a weighted average cost of capital component using the most recently approved base rate return on equity and adjusted for the Company's composite federal and state income tax rate.
4. Total E(m) (sum of each approved Retirement Asset 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 twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).
5. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) months ending with the current expense month. Base revenue includes customer, energy, and lighting charges for each rate schedule included in Group 1 to which this rider is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, Environmental Cost Recovery Surcharge, Off-System Sales Adjustment Clause, and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.
6. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this rider is applicable and automatic adjustment clause revenues for the Environmental Cost Recovery Surcharge and 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.
7. Current expense month (m) shall be the second month preceding the month in which the Retired Asset Recovery Rider is billed.

Proposed

AVAILABILITY OF SERVICE

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges and all Pilot Programs listed in Section 3 of the General Index. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.

Group 2: Rates GS; GTOD-Energy; GTOD-Demand; PS; TODS; TODP; RTS; EHLF; FLS; EVSE; EVC-L2; EVC-FAST; and OSL.

RATE

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

Group RAR Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is Adjusted E(m) for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month.

DEFINITIONS

1.For a retired generating unit and its other site-related assets that will not continue in use, Retirement Costs are the unrecovered amounts of net book value, materials and supplies that cannot be used economically at other plants owned by Company, and costs of removal (i.e., decommissioning and demolition costs net of salvage credits).

2.A Retired Asset is a retired generating unit's Retirement Costs net of related accumulated deferred income tax ("ADIT"). Related ADIT shall include the tax benefits from tax losses.

3.E(m) is (a) the sum of the monthly levelized expense required to amortize each retired generating unit's Retirement Costs over a 10-year amortization period beginning with the month after the month in which the related generating unit retires less (b) the sum of the depreciation expense and return component embedded in base rates for each retired generating unit. E(m) includes a weighted average cost of capital component applied to the Retired Asset using the most recently approved base rate return on equity and adjusted for the Company's composite federal and state income tax rate.

4.E(m) is adjusted for any (Over)/Under collection or prior period adjustment to arrive at Adjusted E(m). Adjusted E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

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

6.The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this rider is applicable and automatic adjustment clause revenues for the Environmental Cost Recovery Surcharge and 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.

7.Current expense month (m) shall be the second month preceding the month in which the Retired Asset Recovery Adjustment Clause is billed.

Other

The Company proposes to apply the approved return on equity in this proceeding to the Retired Asset Recovery Adjustment Clause beginning with the January 2026 expense month.

New – Renewable Power Purchase Agreement Adjustment Clause - RPPA

Applicable:
In all territory served.

Availability:
Mandatory to all electric rate schedules.

Rate:
The monthly RPPA 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:

RPPA Adjustment Factor = (RPPA(m) - REC(m) + BA(m)) / S(m)

Where, in the current period (m) as defined in 807 KAR 5:056:

• "RPPA" is the cost of all renewable power purchase agreements approved by the Commission for cost recovery through Adjustment Clause RPPA ("Approved RPPAs");

• "REC" is (a) all revenue from sales of environmental attributes, including renewable energy certificates, resulting from Approved RPPAs, minus (b) all costs of such sales, including without limitation all costs of making such environmental attributes saleable (e.g., certification and recordation costs);

• "BA" is the balancing adjustment to account for the over- or under-collection of revenues in the billing period due to differences between the kWh sales (S) for the current period (m) and the billing period; and

• "S" is the kWh sales.

The RPPA Adjustment Factor will be applied as set out below.

1.The monthly amount computed under each of the rate schedules to which the RPPA is applicable shall be increased or decreased by the RPPA Adjustment Factor.

2.Current expense month (m) shall be the second month preceding the month in which the RPPA Adjustment Factor is billed.

3.The RPPA Adjustment Factor shall be filed with the Commission ten 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.

<u>Terms and Conditions – Customer Responsibilities</u>

Application for Service:
The Company proposes to add "electronic mail address" to the items it may require of any party applying for service.

Permits, Easement, and Rights of Way:
<u>Current</u>
Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines, Customer shall obtain from the property owner or owners the necessary consent to the installation and maintenance in said premises and in or about such intervening property of all such wiring or other Customer-owned electrical equipment as may be necessary or convenient for the supply of electric service to Customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

The construction of electric facilities to provide service to a number of Customers in a manner consistent with good engineering practice and the least public inconvenience sometimes requires that certain wires, guys, poles, or other appurtenances on a Customer's premises be used to supply service to neighboring Customers. Accordingly, each customer taking Company's electric service shall grant to Company such rights on or across his or her premises as may be necessary to furnish service to neighboring premises, such rights to be exercised by Company in a reasonable manner and with due regard for the convenience of 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.

Proposed

Regarding any and all Customer-owned property, Customer shall grant at no cost to Company or its agent all easements, rights of way, or other consents necessary to allow Company to serve Customer's premises and equipment. Company shall obtain all other permits (including without limitation any necessary street permits), easements, rights of way, or certificates necessary to install and maintain Company-owned facilities. Company shall not be required to supply service under Customer's application until a reasonable time after all required permits (including without limitation any necessary street permits), easements, rights of way, or certificates are granted or otherwise obtained.

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 as well as Customer. Accordingly, insofar as such facilities also serve Customer, Customer 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.

Terms and Conditions – Company Responsibilities

New – Incidental or Occasional Utility-Related Services:

Upon Customer’s request, Company may perform incidental or occasional utility-related services not addressed by other tariff provisions. If Company agrees to perform such Customer-requested services, Company will bill Customer for reimbursement of Company’s costs, including without limitation costs of materials and labor required to perform such services.

Terms and Conditions – Billing

Meter Readings and Bills

New Language Added

All Customers for whom Company has an email address on file will receive paperless bills by default. Customers may opt out of paperless billing by contacting Company to request paper bills by mail.

Terms and Conditions – Deposits

Current

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. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1. Residential Customers are those Customers served under Residential Service Rate RS - Sheet No. 5, Residential Time-of-Day Energy Service Rate RTOD-Energy – Sheet No. 6, and Residential Time-of-Day Demand Service Rate RTOD-Demand – Sheet No. 7.

2. The deposit for a residential Customer is in the amount of $160.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2). For combination gas and electric Customers, the total deposit will be $260.00.

3. Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

4. If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

5. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

GENERAL SERVICE

1. General service Customers are those Customers served under General Service Rate GS, Sheet No. 10, General Time-of-Day Energy Service Rate GTOD-Energy Sheet No. 11, and General Time-of-Day Demand Service Rate GTOD-Demand Sheet No. 12.

2. The deposit for a general service customer is in the amount of $240.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2).The deposit for a General Service Customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service energy usage is no more than 300 kWh per month.

3. Company shall retain Customer’s deposit as long as Customer remains on service.

4. For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

5. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or

additional deposit from Customer.

OTHER SERVICE

1. The deposit for all other Customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d)(1).
2. For Customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3. For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer

Proposed

GENERAL

1. To the extend set forth herein, Company will 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 will 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 or financial watch services.

b. Satisfactory payment criteria with Company will be established by timely 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, and having no history of fraud or attempted gaming of Company's payment or deposit requirements to obtain service.

3. To the extent set forth herein, Company will allow residential and general service Customers to pay any required deposit(s) in equal installments over the first six 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. If interest is paid or credited to Customer's bill prior to 12 months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
5. Any deposit, surety bond, letter of credit, or other form of security currently held by or later provided to Company by Customer to secure payment of Customer's bills for a particular account with Company shall also secure any and all other obligations owing to Company by Customer. Should Customer fail to timely pay or perform any obligation owing by it to Company on any one or more of its accounts, Company may apply any security held by it for Customer, regardless of the account for which it was given, to satisfy Customer's outstanding obligations.
6. For Customer's account to be in "good standing," Customer must not have:

a. Received a disconnection notice, late payment notice, or budget reminder letter from Company;
b. Defaulted on a payment installment plan arranged with Company;
c. Issued a payment to Company that was returned for insufficient funds or any other reason; or
d. Engaged in an unauthorized reconnection of service or diversion of service.

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. 2. The deposit amount for a residential Customer is $160.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2).
3. The criteria Company uses to determine whether to require a deposit from a residential Customer are below.

a. For a Customer not currently taking any service from Company
i. Company will run a credit check with Customer's permission and if results indicates a deposit should be charged, Customer will be required to pay a deposit.
ii. If Customer refuses to allow Company to run a credit check or does not provide information needed to run a credit check, Company will require Customer to pay a deposit.
iii. If a residential Customer adds a General Service meter for a detached structure such as a barn or garage and if Company anticipates the new structure will consume less than 300 kWh per month, Company will not require a deposit for the General Service meter. If Company anticipates the new structure will consume 300 kWh or more per month, Company will require a deposit for the General Service meter in accordance with the General Service deposit provisions below.
b. For a Customer currently taking any service from Company for which the Company is holding a deposit and Customer is requesting service for another premise:
i. Company will require a deposit for the new service if in the last 12 months Customer has had any account(s) not in good standing.
ii. If Customer disputes Company's deposit requirement for the new service based on Customer's payment history, Company will, with Customer's permission and provision of any required information, run a credit check. If the results indicate a deposit is not needed, Company will not require Customer to pay a deposit for the new service.
c. If Customer seeks to transfer existing service to another premise:
i. If Company is not currently holding a deposit for Customer for Customer's existing active service, Company will not require a deposit from Customer for the new service at Customer's new premise.
ii. If Company is currently holding a deposit for Customer for Customer's existing service, Company will not require a new or additional deposit from Customer for the new service at Customer's new premise, and Customer's move will not affect the date Company will review the deposit for release thereof. Also, if Customer is making deposit installment payments for service at Customer's current premise, the same installment payments made and interest thereon will transfer to Customer's service at Customer's new premise, and Customer's deposit payment installment plan will also transfer to Customer's service at Customer's new premise.
d. If Company is not currently holding a deposit for Customer and if Customer's service is disconnected for non-payment and is subsequently reconnected, Company will require a full deposit from Customer to resume service. Consistent with 807 KAR 5:006 Section 16, this requirement does not apply to winter hardship reconnections.
e. If Customer is financially responsible for the service of another Customer and the financially responsible Customer is taking over the other Customer's existing service:
i. If the existing Customer's account is in good standing and the financially responsible Customer taking over the existing service has no past-due balance(s) on any account(s) with Company, Company will not require a deposit from the financially responsible Customer to take over the existing service.

ii. If the existing Customer's account is not in good standing, Company will run a credit check on the financially responsible Customer (with the Customer's permission).

1. If Company runs a credit check on Customer and the results indicate a deposit is not needed, Company will not require Customer to pay a deposit.

2. If Customer refuses to allow Company to run a credit check or does not provide information needed to run a credit check, Company will require Customer to pay a deposit.

3. If Company runs a credit check on Customer and the results indicate a deposit is needed, Company will require Customer to pay a deposit.

f. If Customer is deceased, Company will not require a new deposit of the Customer assuming responsibility for the service on behalf of the deceased Customer.

4. Company shall retain Customer's deposit for a period not to exceed 12 months, if Customer has met satisfactory payment and credit criteria.

5. 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.

6. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

GENERAL SERVICE

1. General Service Customers are those Customers served under General Service Rate GS, Sheet No. 10, General Time-of-Day Energy Service Rate GTOD-Energy Sheet No. 11, and General Time-of-Day Demand Service Rate GTOD-Demand Sheet No. 12.

2. The deposit amount for a General Service Customer is $240.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2).

3. The criteria Company uses to determine whether to require a deposit from a General Service Customer are below.

a. Company will require a deposit from all new General Service Customers with one exception: Company will waive the deposit for a General Service Customer if the service is for a detached building used in conjunction with a Residential Service and the General Service energy usage is no more than 300 kWh per month.

b. If Customer currently takes any service from Company and requests service for another premise, Company will require a deposit for the new service if in the last 36 months Customer has had any account(s) not in good standing.

c. If Customer seeks to transfer existing service to another premise:

i. If Company is not currently holding a deposit for Customer for Customer's existing active service, Company will not require a deposit from Customer for the new service at Customer's new premise.

ii. If Company is currently holding a deposit for Customer for Customer's existing service, Company will not require a new or additional deposit from Customer for the new service at Customer's new premise, and Customer's move will not affect the date Company will review the deposit for release thereof. Also, if Customer is making deposit installment payments for service at Customer's current premise, the same installment payments made and interest thereon will transfer to Customer's service at Customer's new premise, and Customer's deposit payment installment plan will also transfer to Customer's service at Customer's new premise.

iii. If Customer moves to a new premise at which Customer will take more services from Company (i.e., both electric and gas service) than Customer currently takes from Company at Customer's existing premise (i.e., electric or gas service only), Company will not require an additional deposit for the additional service.

iv. If Customer moves to a new premise at which Customer will take fewer services from Company (i.e., electric or gas service only) than Customer currently takes from Company at Customer's existing premise (i.e., both electric and gas service), Company will apply to Customer's final bill at Customer's existing premise any existing deposit and accumulated interest in excess of the deposit required for the service Customer will take at Customer's new premise.

d. If Customer's service is disconnected for non-payment and is subsequently reconnected, Company will require a full deposit from Customer to resume service.

e. If Customer is financially responsible for the service of another Customer and the financially responsible Customer is taking over the other Customer's existing service, Company will require the financially responsible Customer to pay a deposit.

4. Company shall retain Customer's deposit as long as Customer remains on service.

5. For a deposit held longer than 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%, 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.

6. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1. For all other Customers, the deposit shall be 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d)(1).

2. The criteria Company uses to determine whether to require a deposit from such a Customer are below.

a. Company will require a deposit from all new Customers.

b. Company will require a deposit for any new service with a contract demand of at least 250 kW.

c. For a Customer currently taking any service from Company and requesting another service under Rate PS, Company will require a deposit for the new service if in the last 36 months Customer has had any account not in good standing.

d. If Customer seeks to transfer existing service to another premise:

i. If Company is not currently holding a deposit for Customer's existing service, Company will not require a deposit from Customer.

ii. If Company is currently holding a deposit for Customer's existing service, Company will not require a new or additional deposit from Customer, and Customer's move will not affect the date Company will review the deposit for release. Also, if Customer is making deposit installment payments for service at Customer's current premise, the same installment payments made and interest thereon will transfer to Customer's service at Customer's new premise, and Customer's deposit payment installment plan will also transfer to Customer's service at Customer's new premise.

iii. If Customer moves to a new premise at which Customer will take more services from Company (i.e., both electric and gas service) than Customer currently takes from Company at Customer's existing premise (i.e., electric or gas service only), Company will not require an additional deposit for the additional service.

iv. If Customer moves to a new premise at which Customer will take fewer services from Company (i.e., electric or gas service only) than Customer currently takes from Company at Customer's existing premise (i.e., both electric and gas service), Company will apply to Customer's final bill at Customer's existing premise any existing deposit and accumulated interest in excess of the deposit required for the service Customer will take at Customer's new premise.

e. If Customer's service is disconnected for non-payment and is subsequently reconnected, Company will require a full deposit from Customer to resume service.

f. If Customer is financially responsible for the service of another Customer and the financially responsible Customer is taking over the other Customer's existing service, Company will require the financially responsible Customer to pay a deposit.

3. Company shall retain Customer's deposit as long as Customer remains on service.

4. For a deposit held longer than 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%, 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.

New - Terms and Conditions – Pre-Pay Program

AVAILABILITY

Available to all residential customers not on net metering service, RTOD-E, RTOD-D, GS, GTOD-E, or GTOD-D. Customers must:

- Have email and text capability on file with the Company
- Have an AMI meter
- Not possess a past due balance greater than $250
- Not have a medical alert, disconnection moratorium, or special rider and cannot participate in budget billing, flex pay, or auto pay programs

TERMS AND CONDITIONS

1. All customers participating in the Pre-Pay Program will be subject to the applicable rates, rules, and regulations of their associated standard rate schedule.
2. Any customer choosing to enroll in the Pre-Pay Program shall sign a Pre-Pay Program Service Agreement. The Agreement shall remain in effect until the customer notifies the Company of their intention to cancel the Agreement.
3. Customers enrolling in the program will require a minimum starting account balance of $30. The current security deposit on file with the Company qualifies.
4. All non-energy charges (Franchise Fee, HEA, etc.) will be pro-rated daily across a customer's monthly billing cycle.
5. A Pre-Pay Program customer will be disconnected without a disconnection notice if the balance becomes negative.
6. If disconnected, customers will be required to have an account balance of $30 before they will be reconnected.
7. If a request for disconnection of a Pre-Pay Program account is made, any remaining balance will be transferred to other active accounts, or if not applicable, or refunded.
8. Program participants may not possess a past due balance greater than $250. If a customer has a past due balance, 30% of each payment will be applied towards the past due balance.
9. Program participants will receive an electronic monthly bill by email and text.
10. Customers will receive low-funds notifications at pre-determined triggers. Customers may also add their own triggers as well.
11. Customers may use all existing payment channels to add funds to their account.
12. Customers that choose to leave the prepay program for the standard residential program will need to provide a security deposit as required in the applicable standard rate schedule.
13. Customers that choose to leave the Pre-Pay Program for service under another tariff will not be allowed to return to the program for twelve (12) months.
14. Program participants will not be eligible for Hardship Waivers or Medical Letters.

15. Low-income agencies will be able to provide financial assistance to prepay customers.
16. If the AMI meter stops communicating, LKE will take steps necessary to secure a daily reading such as adding additional equipment. Until the readings are secured, the daily process is suspended as well. However, when the reading is secured, the billing process will resume and be deducted from the credit balance.

Terms and Conditions – Discontinuance of Service

Current

3. 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.

8. 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.

Proposed

3. When Customer or Applicant refuses or neglects to provide reasonable access 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 ten (10) days written notice (either mailed or otherwise delivered, including, but not limited to, electronic mail), of Company's intention to discontinue or refuse service.

8. 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 (with "mailing" to include all other reasonable forms of delivering written communications, including without limitation electronic 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.

Terms and Conditions – Line Extension Plan

4b. Normal Line Extensions

Current

Where Non-Residential Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide at its own expense the requested line extension, but only to the extent that the cost of the requested extension does not exceed the lesser of (i) the cost of a comparable overhead extension (if an underground extension is requested) or (ii) five (5) times Customer's estimated annual net revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel Adjustment Clause, Off-System Sales, Demand Side Management, franchise fees, and school taxes. Company may require Non-Residential Customer to pay in advance a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above. Customer must commit to a minimum contract term of five (5) years.

Proposed

Where Non-Residential Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide at its own expense the requested line extension, but only to the extent that the cost of the requested extension does not exceed the lesser of (i) the cost of a comparable overhead extension (if an underground extension is requested) or (ii) five (5) times Customer's estimated annual net revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel Adjustment Clause, Off-System Sales, Environmental Cost Recovery Surcharge, Demand Side Management, Retired Asset Recovery, Renewable Power Purchase Agreement Adjustment Clause, franchise fees, and school taxes. Company may require Non-Residential Customer to pay in advance a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above. Customer must commit to a minimum contract term of five (5) years.

5e. Other Line Extensions

Current

Where Non-Residential Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide at its own expense the requested line extension, but only to the extent that the cost of the requested extension does not exceed the lesser of (i) the cost of a comparable overhead extension (if an underground extension is requested) or (ii) five (5) times Customer's estimated annual net revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel Adjustment Clause, Demand Side Management, franchise fees, and school taxes. Company may require Non-Residential Customer to pay in advance a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above.

Proposed

Where Non-Residential Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide at its own expense the requested line extension, but only to the extent that the cost of the requested extension does not exceed the lesser of (i) the cost of a comparable overhead extension (if an underground extension is requested) or (ii) five (5) times Customer's estimated annual net revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel Adjustment Clause, Off-System Sales, Environmental Cost Recovery Surcharge, Demand Side Management, Retired Asset Recovery, Renewable Power Purchase Agreement Adjustment Clause, franchise fees, and school taxes. Company may require Non-Residential Customer to pay in advance a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above.

New - Terms and Conditions – Rules for Transmission-Level Retail Electric Service Studies and Related Implementation Costs

REQUESTS TO STUDY TRANSMISSION-LEVEL RETAIL ELECTRIC SERVICE

For the purposes of this section of Company's Terms and Conditions, "transmission-level retail electric service" means any proposed retail electric service requiring Company to submit a Transmission Service Request to Company's Independent Transmission Organization.

Upon request, Company will cause to be studied the requirements and costs to provide transmission level retail electric service to new or existing facilities according to the terms and conditions set forth herein (such study is the "Service Study"; the service studied is the "Studied Service"). Company will provide the resulting cost estimates to the party requesting the Service Study ("Requester"). Company will process such requests as it deems most likely to result in the orderly and economical processing thereof, not necessarily in the order received.

Requester will reimburse Company for all Service Study-related costs, including without limitation the costs of studies required to be conducted by third parties, including those conducted by Company's Independent Transmission Organization.

COST RESPONSIBILITY AND REQUIREMENT TO ENTER INTO BINDING AGREEMENT(S)

For the purposes of this section of Company's Terms and Conditions, "implementation costs" include without limitation transmission-related engineering, procurement, and construction costs Requester asks Company to incur, and Company agrees to incur, related to the Studied Service.

If Requester is not a Customer, Company will require Requester, one or more other responsible parties, or both (collectively "Responsible Parties") to enter into all contracts or other agreements Company deems necessary to ensure recovery of all implementation costs. If Requester is a Customer, Company will require Responsible Parties to enter into all contracts or other agreements Company deems necessary to ensure recovery of all implementation costs in excess of $10 million.

Such contracts or other agreements will include without limitation requirements for Responsible Parties to provide adequate collateral, credit assurance, or other security satisfactory to Company in its sole discretion to ensure recovery of the costs described or contemplated herein.

<u>Terms and Conditions – Net Metering Service Interconnection Guidelines</u>

<u>Current</u>

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.

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, 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 Company's technical interconnection requirements. Those requirements are available on line at www.lge-ku.com and upon request.

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, 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 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 Kentucky Public Service Commission;

d.the rules and regulations of the Kentucky Public Service Commission, as may be revised by time-to-time by the Kentucky Public Service Commission:

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 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 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 rider.

Where required by 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 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 rider 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 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.

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 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 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, 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, 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.

Proposed
GENERAL
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 additional cost to Customer. This provision does not relieve Customer's responsibility to pay metering costs embedded in Company's Commission-approved base rates. Additional meters, requested by Customer, will be provided at Customer's expense.

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 for the primary purpose of supplying all or part of the customer's own electricity requirements. 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 ensuring an anti-islanding safety feature is in place as required by applicable codes and standards.
3.Customer will ensure that all generating facilities comply with the Company's Interconnection Requirements for Customer-Sited Distributed Generation. Those requirements are available on line at www.lge-ku.com and upon request.
4.Customer shall allow data communications between the Customer's distributed generation equipment and the Company's control systems or other assets, where required by the Company for planning, coordination, reliability, or power quality purposes.
5.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.
6. Customer will be responsible for any damage done to Company's equipment due to failure of Customer's control, safety, or other equipment.
7.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.
8.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.
9.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.

Customer recognizes that Company may or may not have adequate facilities to serve customer's total load at the time of any partial or full failure of customer's self-generation. Company will work with the customer to serve their load requirements which may be at additional cost to the customer.

Level 1 – A Level 1 installation is defined as an inverter-based generator certified as meeting the requirements of Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, 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.
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 UL 1741 or IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8.Company will not be required to construct or upgrade 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, 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. Following Company approval of an application, any deviations in the installation from the submitted plan must be re-submitted to the Company for approval. This includes, but is not limited to: modifications in generation capacity, equipment selection, installation methods, and installation of additional equipment. Any modification in generation capacity related to existing customers taking service under NMS-1 will cause their service to be transitioned to NMS-2. Customer submitting a "Level 1 - Application for Interconnection and Net Metering" will provide a non-refundable inspection and processing fee of $100, and in the event that 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.

Level 2 – A Level 2 installation is defined as generator that does not meet one or more of the conditions required of a Level 1 net metering generator; that is not inverter-based; or that uses equipment not certified as meeting the requirements of IEEE 1547 and UL 1741.

Customer desiring a Level 2 interconnection shall submit a "LEVEL 2 - Application for Interconnection and Net Metering." Company shall notify Customer within 30 business days as to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, 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. Following Company approval of an application, any deviations in the installation from the submitted plan must be re-submitted to the Company for approval. This includes, but is not limited to: modifications in generation capacity, equipment selection, installation methods, and installation of additional equipment.

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 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 Interconnection Requirements for Customer-Sited Distributed Generation, applicable codes and standards, 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 design installation, troubleshooting, maintenance and safe operation of the net metering generating facility. The customers acknowledge and agrees that any concerns relating to the generation system's performance, including but not limited to energy output, equipment malfunctions, or compliance with applicable codes and standards, shall be addressed solely by the customer and their installer. The utility shall be held harmless from any claims, damages, or liabilities arising from the operation or failure of the customer's generation system, including any impact on the customer's energy production or financial return on investment. The customer may request a meter calibration test at their expense. 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, UL and accredited testing laboratories;

b.NFPA 70, National Electric Code (NEC), as may be revised from time-to-time;

c. Company's Interconnection Requirements for Customer-Sited Distributed Generation;

d.Company's rules and regulations and Terms and Conditions, as may be revised by time-to-time by the Kentucky Public Service Commission;

e.the rules and regulations of the Kentucky Public Service Commission, as may be revised by time-to-time by the Kentucky Public Service Commission:

f.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 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 Company.

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 rider.

7.Where required by 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. Certain installations meeting a list of requirements specified in the Company's Interconnection Requirements for Customer-Sited Distributed Generation may be exempt from the EDS requirement. 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 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 rider 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 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 all applicable codes and standards certification requirements, including but not limited to IEEE 1547 and UL 1741, 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 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 Customer's 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 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, 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, 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 Certificates (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.

Net Metering Applications moved to Companies' Net Metering website (https://lge-ku.com/residential/net-metering)

Kentucky Utilities Company also proposes to change the text of the following electric tariff rate schedules and provisions: 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, General Time-of-Day Energy Service GTOD-Energy, General Time-of-Day Demand Service GTOD-Demand, All-Electric School Service 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, Lighting Energy Rate LE, Traffic Energy Service Rate TE, Pole and Structure Attachment Charges PSA, Electric Vehicle Supply Equipment Rate EVSE, Electric Vehicle Charging Service EVC, Outdoor Sports Lighting OSL, Special Charges, Curtailable Service Rider-1 CSR-1, Curtailable Service Rider-2 CSR-2, Small Capacity Cogeneration and Small Power Production Qualifying Facilities (SQF), Large Capacity Cogeneration and Large Power Production Qualifying Facilities (LQF), Net Metering Service-1 (NMS-1), Net Metering Service-2 (NMS-2), Excess Facilities (EF), Green Tariff Rider GT, Economic Development Rider EDR, Solar Share Program Rider SSP, Fuel Adjustment Clause FAC, Environmental Cost Recovery Mechanism ECR, Electric Vehicle Supply Equipment Rider EVSE-R, Demand-Side Management Cost Recovery Mechanism DSM, Retired Asset Recovery RAR, and the Terms and Conditions.

KU proposes to add one new electric rate schedule, Extremely High Load Factor Service (“EHLF”), one new electric adjustment clause, Renewable Power Purchase Agreement Adjustment Clause (“RPPA”), one new customer program, Pre-Pay Program, and one new tariff for Terms and Conditions (“Rules for Transmission-Level Retail Electric Studies and Related Implementation Costs.

KU’s proposed rates reflect a proposed annual increase in electric revenues of approximately 11.5%.

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	1,085	99,997,335	13.55	18.15	13.55
Residential Time-of-Day	1,245	23,833	13.05	18.53	13.05
General Service	1,657	25,335,181	9.21	24.41	9.22
General Time-of-Day	19,507	2,400	8.22	198.49	8.22
All Electric School	25,620	1,449,553	10.91	314.15	10.91
Power Service	30,651	17,655,788	9.15	349.93	9.15
Time-of-Day Secondary	189,538	17,929,669	10.87	1,846.64	10.87
Time-of-Day Primary	1,242,574	33,834,832	11.15	10,609.74	11.15
Retail Transmission	7,387,224	13,634,683	11.00	54,105.89	11.00
Extremely High Load Factor	New Rate Schedule				
Fluctuating Load Service	44,229,667	2,528,016	6.90	210,667.98	6.90
Outdoor Lights	51	3,624,095	11.37	1.67	11.40
Lighting Energy	2,473	42,734	11.14	21.99	11.14
Traffic Energy	146	26,391	10.58	1.91	10.60
Outdoor Sports Lighting	4,627	(37)	(0.04)	(0.52)	(0.04)
Rider – CSR	N/A	0	0.00	0.00	0.00

A detailed notice of all proposed revisions and a complete copy of the proposed tariffs containing the proposed text changes, terms and conditions and rates may be obtained by submitting a written request by e-mail to myaccount@lge-ku.com or by mail to Kentucky Utilities Company, ATTN: Rates Department, 2701 Eastpoint Parkway, Louisville, Kentucky, 40223, or by visiting KU's website at https://lge-ku.com/ku-2025-rate-case.

A person may examine KU's application at KU's office at One Quality Street, Lexington, Kentucky, 40507, and at KU's website at https://lge-ku.com/ku-2025-rate-case. 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 may view and download the application 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 email to psc.info@ky.gov. All comments should reference Case No. 2025-00113.

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 this notice, the Commission may take final action on the application.

Exhibit D

Customer Bill Insert

General Statement

NOTICE TO CUSTOMERS OF KENTUCKY UTILITIES COMPANY

PLEASE TAKE NOTICE that, in a May 30, 2025 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 July 1, 2025.

The proposed rates and charges reflect a proposed annual increase in revenues of approximately 11.5% to KU.

The estimated amount of the annual change and the average monthly bill to which the proposed electric rates and charges will apply for each electric rate class are as follows:

Electric Rate Class	Average Usage (kWh)	Annual $ Increase	Annual % Increase	Monthly Bill $ Increase	Monthly Bill % Increase
Residential	1,085	99,997,335	13.55	18.15	13.55
Residential Time-of-Day	1,245	23,833	13.05	18.53	13.05
General Service	1,657	25,335,181	9.21	24.41	9.22
General Time-of-Day	19,507	2,400	8.22	198.49	8.22
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Power Service	30,651	17,655,788	9.15	349.93	9.15
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Time-of-Day Primary	1,242,574	33,834,832	11.15	10,609.74	11.15
Retail Transmission	7,387,224	13,634,683	11.00	54,105.89	11.00
Extremely High Load Factor	New Rate Schedule				
Fluctuating Load Service	44,229,667	2,528,016	6.90	210,667.98	6.90
Outdoor Lights	51	3,624,095	11.37	1.67	11.40
Lighting Energy	2,473	42,734	11.14	21.99	11.14
Traffic Energy	146	26,391	10.58	1.91	10.60
Outdoor Sports Lighting	4,627	(37)	(0.04)	(0.52)	(0.04)
Rider – CSR	N/A	0	0.00	0.00	0.00

A detailed notice of all proposed revisions and a complete copy of the proposed tariffs containing the proposed text changes, terms and conditions and rates may be obtained by submitting a written request by e-mail to myaccount@lge-ku.com or by mail to Kentucky Utilities Company, ATTN: Rates Department, 2701 Eastpoint Parkway, Louisville, Kentucky, 40223, or by visiting KU's website at https://www.lge-ku.com/ku-2025-rate-case.

A person may examine KU's application at KU's office at One Quality Street, Lexington, Kentucky, 40507, and at KU's website at https://www.lge-ku.com/ku-2025-rate-case. 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 may view and download the application 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 email to psc.info@ky.gov. All comments should reference Case No. 2025-00113.

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 this notice, the Commission may take final action on the application.

Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 7 - 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 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 for the notice of intent and the email transmission to the Attorney General's Office of Rate Intervention.

The Commission granted the request of KU and LG&E to publish an abbreviated newspaper customer notice.[2]

[2] *In the Matters of: Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates; Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates,* Case Nos. 2025-00113 and 2025-00114, Order (Ky. PSC May 5, 2025), Ordering Paragraph.

Robert M. Conroy
Vice President
State Regulation and Rates
O 502-627-3324
robert.conroy@lge-ku.com

a PPL company

Linda C. Bridwell, PE
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8295

April 4, 2025

RE: Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Approval of Certain Regulatory and Accounting Treatments
Case No. 2025-_____

Dear Ms. Bridwell:

Please take notice that Kentucky Utilities Company ("KU") intends to file on or after May 30, 2025, an application for a general adjustment in its electric rates, including changes to its electric tariffs, and certain regulatory and accounting treatments. This application will be supported by a fully forecasted test period ending December 31, 2026.

KU is contemporaneously filing 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.

Under separate cover, KU will be filing a motion for an order approving a deviation on method of notice of publication and certain rules of procedure.

Should you have any questions, please do not hesitate to contact me.

Sincerely,

Robet M. Conroy

cc: Case No. 2020-00349 Parties of Record (via email)

Robert M. Conroy
Vice President
State Regulation and Rates
O 502-627-3324
robert.conroy@lge-ku.com

a PPL company

Linda C. Bridwell, PE
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8295

April 4, 2025

RE: Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Approval of Certain Regulatory and Accounting Treatments
Case No. 2025-_____

Dear Ms. Bridwell:

Please find enclosed and accept for filing a notice of election of use of electronic filing procedures in accordance with 807 KAR 5:001, Section 8 for Kentucky Utilities Company ("KU").

Under separate cover, KU is giving notice this same day of its intention to file on or after May 30, 2025, an application for a general adjustment in its electric rates, including changes to its electric tariffs, and certain regulatory and accounting treatments. This application will be supported by a fully forecasted test period ending December 31, 2026.

Should you have any questions, please do not hesitate to contact me.

Sincerely,

Robet M. Conroy

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 an adjustment of its electric rates with the Public Service Commission no later than May 30, 2025 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	asturgeon@pplweb.com
Lindsey W. Ingram III	lingram@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

Name: Robert M. Conroy
Title: Vice President
Address: 2701 Eastpoint Parkway
Louisville, KY 40223
Telephone Number: 502-627-3324

From: Lovekamp, Rick
To: PSC Executive Director
Cc: Angela M. Goad (Angela.Goad@ky.gov); Barry A. Naum (bnaum@spilmanlaw.com); Carrie H. Grundmann (cgrundmann@spilmanlaw.com); Clay A. Barkley (cbarkley@strobobarkley.com); David E. Spenard (dspenard@strobobarkley.com); David J. Barberie (dbarberi@lexingtonky.gov); Don C.A. Parker (dparker@spilmanlaw.com); Emily W. Medlyn (emily.w.medlyn.civ@mail.mil); G. Houston Parrish (glenn.h.parrish.civ@mail.com); James W. Gardner (jgardner@sturgillturner.com); Jeff DeRouen (Jeff.Derouen@louisvilleky.gov); Jody Kyler Cohn (jkylercohn@BKLlawfirm.com); Joe F. Childers (joe@childerslaw.com); John G. Horne (John.Horne@ky.gov); Kurt J. Boehm (kboehm@BKLlawfirm.com); Kurtz, Michael L. (mkurtz@BKLlawfirm.com); Lauren Givhan (Lauren.Givhan@louisvilleky.gov); Lawrence W. Cook (Larry.Cook@ky.gov); M. Todd Osterloh (tosterloh@sturgillturner.com); Matthew E. Miller (matthew.miller@sierraclub.org); Mike West (Michael.West@ky.gov); Quang D. Nguyen; Randal A. Strobo (rstrobo@strobobarkley.com); Robert C. Moore (rmoore@stites.com); Susan Speckert (sspeckert@lexingtonky.gov); Tom FitzGerald (FitzKRC@aol.com); Sturgeon, Allyson; Judd, Sara; Lindsey Ingram; Conroy, Robert
Subject: Kentucky Utilities Company - Notice of Intent and Notice of Election of Use of Electronic Filing
Date: Friday, April 4, 2025 2:32:00 PM
Attachments: 20250404_KU_Notice_of_Intent.pdf
20250404_KU_Notice_of_Electronic_Filing.pdf

Kentucky Utilities Company submits a Notice of Intent and Notice of Election of Use of Electronic Filing Procedures.

Please contact me with any questions.

Regards,
Rick E. Lovekamp
Sr. Manager Regulatory Strategy/Policy | State Regulation and Rates | LG&E and KU
2701 Eastpoint Parkway, Louisville, KY 40223
O: 502-627-3780
lge-ku.com

Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 8 - 807 KAR 5:001 Section 16(6)(a)
Sponsoring Witness: Robert M. Conroy

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. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 9 - 807 KAR 5:001 Section 16(6)(b)
Sponsoring Witness: Robert M. Conroy

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. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 10 - 807 KAR 5:001 Section 16(6)(c)
Sponsoring Witness: Robert M. Conroy

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. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 11 - 807 KAR 5:001 Section 16(6)(d)
Sponsoring Witness: Robert M. Conroy

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. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 12 - 807 KAR 5:001 Section 16(6)(e)
Sponsoring Witness: Robert M. Conroy

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. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 13 - 807 KAR 5:001 Section 16(6)(f)
Sponsoring Witness: Andrea M. Fackler

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

Explanation of Differences between 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)		93.25%	6.75%
2	Capitalization	$ 8,047,708,246	$ 6,186,741,227	$ 542,933,998
2	Rate Base	7,967,281,242	6,094,469,285	537,623,314
3	**Difference**	$ 80,427,004	$ 92,271,942	$ 5,310,683
4	**Items not included in Rate Base:**			
5	ARO Liabilities	$ (50,581,380)	$ (47,167,137)	$ (3,414,243)
6	ARO Assets		21,397,234	
7	Net Balance Sheet Working Capital	24,317,854	22,676,399	1,641,455
8	Net Regulatory Assets/Liabilities	110,663,665	103,193,867	7,469,797
9	Accumulated Deferred IncomeTaxes	5,090,661	4,747,041	343,620
10	Leases	(485,424)	(452,658)	(32,766)
11	Miscellaneous Deferred Debit	35,192,990	32,817,463	2,375,527
12	Other Property and Investments	287,881		
13	ADIT Proration		(455,171)	(32,948)
14	AMI		992,436	71,839
15	CPCN New Generation		(5,511,579)	(398,962)
16	IT Software Cost Regulatory Asset		1,588,939	115,017
17	EEI Deferred taxes		(301,479)	(21,823)
18	**Items included in rate base:**			
19	Cash Working Capital (Income Statement)	(44,059,243)	(39,263,195)	(4,796,048)
20	Capitalization / Rate Base Allocation Differences	-	(1,990,219)	1,990,219
21	**Total Reconciling Items**	$ 80,427,004	$ 92,271,942	$ 5,310,683

Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 14 - 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:

John R. Crockett III
Lonnie E. Bellar
Charles R. Schram
Elizabeth J. McFarland
Peter W. Waldrab
Shannon L. Montgomery
Vincent T. Poplaski
Julissa Burgos
Dylan W. D'Ascendis
Christopher M. Garrett
Heather D. Metts
Drew T. McCombs
John J. Spanos
Daniel Johnson
Robert M. Conroy
Andrea M. Fackler
Michael E. Hornung
Timothy S. Lyons

Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 15 - 807 KAR 5:001 Section 16(7)(b)
Sponsoring Witness: Heather D. Metts

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. 2025-00113
Capital Expenditure Budget
Years 2025-2028

	Projected Capital Expenditures			
Category of Spend	**2025**	**2026**	**2027**	**2028**
Generation	521,550,017	607,216,881	558,658,524	269,769,619
Transmission	189,949,455	347,049,478	352,552,656	380,528,139
Distribution	201,722,430	275,506,213	250,546,759	252,917,352
Customer Services	29,242,290	1,110,608	2,254,814	2,391,929
IT & Other	71,023,354	92,080,569	59,179,078	42,783,413
Total	**1,013,487,547**	**1,322,963,748**	**1,223,191,831**	**948,390,453**

Kentucky Utilities Company
Case No. 2025-00113
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 12/31/26; Base Period 12ME 8/31/25)

Filing Requirement
Tab 16 - 807 KAR 5:001 Section 16(7)(c)
Sponsoring Witnesses: Heather D. Metts / Charles R. Schram

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 Heather D. Metts and Charles R. Schram 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	Heather D. Metts
B.	Electric Sales and Demand Forecast Process	Charles R. Schram
C.	2025 Business Plan Electric Sales Forecast	Charles R. Schram
D.	[This line intentionally left blank]	
E.	Electric Class Load Profile Forecast Process	Charles R. Schram
F.	[This line intentionally left blank]	
G.	Generation Forecast Process	Charles R. Schram
H.	2025 Business Plan Generation and OSS Forecast	Charles R. Schram
I.	Line of Business Presentations	Heather D. Metts

Financial Planning Modeling Process

Table of Contents

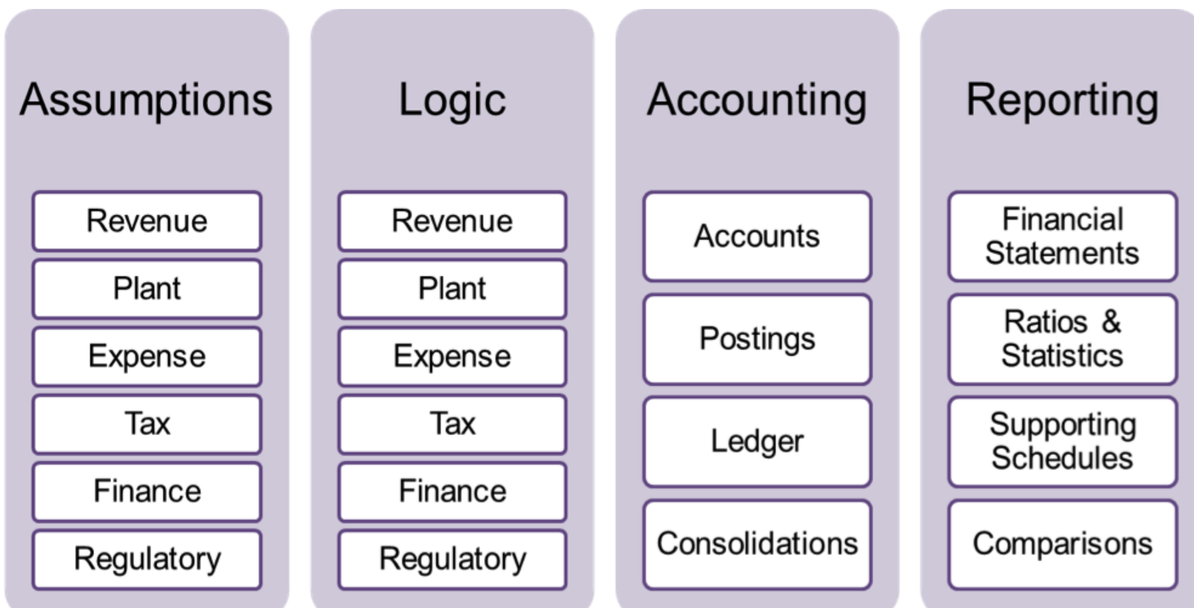
1. General

Introduction

The Financial Planning & Analysis group develops the five-year Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") and LG&E and KU Energy LLC ("LKE" or collectively "the Companies") business plan. The business plan is developed using the financial planning system, UIPlanner, an iterative model, which incorporates numerous inputs from the business as well as various formulas, algorithms and set logic. The business plan includes the projected five-year income statements, balance sheets and cash flows for the Companies.

UIPlanner (UI)

UI allows the Companies 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.



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.). 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 the production of financial statements. These summary accounts are rolled up into a high-level area (asset, direct cash, expense, indirect cash, liability, or revenue). Each account in the ledger is also associated with an indirect cash flow account which can be customized to generate a detailed cash flow statement.

Planning Ledger Process

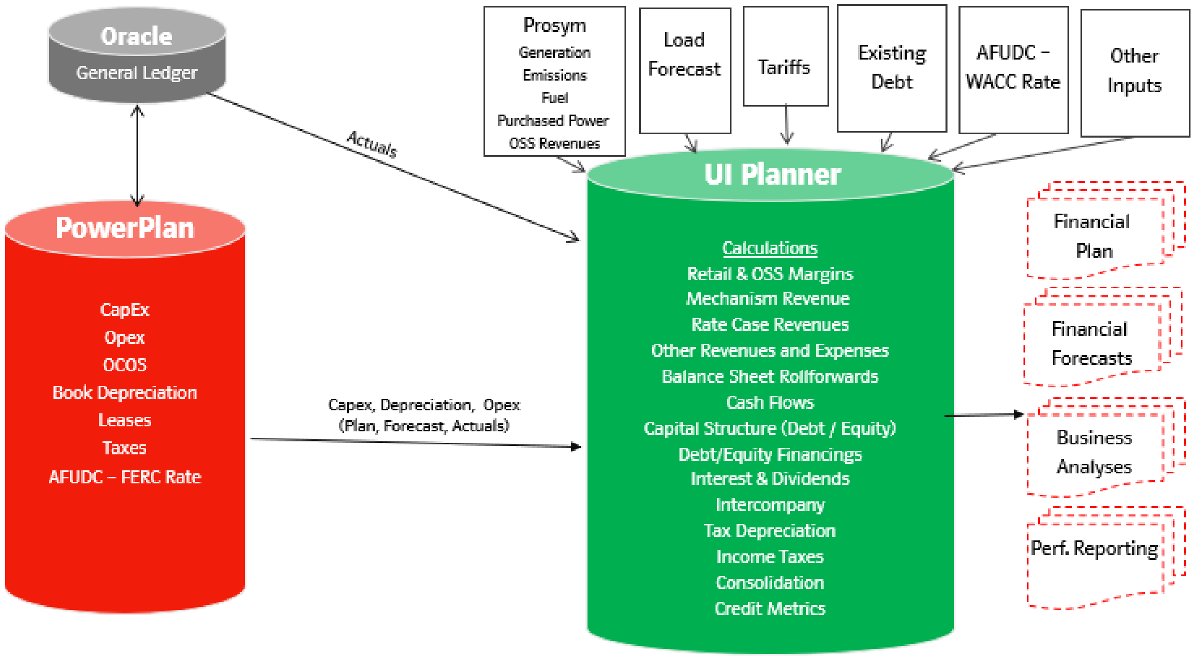
Each month actual balances are imported from the Oracle General Ledger (GL) to update UI with the latest balances and to compare the budget and revised forecast to actuals. The actuals imported into UI are compared to the trial balance in Oracle monthly to ensure completeness and accuracy.

Data in UI is entered into UI either manually, through a download from text files, or interfaces with PowerPlan or Oracle and housed within "cases". A collection of cases is grouped to create a "scenario". For example, the "2025 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 and modify logic assumptions. In addition, when a scenario, such as the business plan, is finalized, the scenario is locked so no further changes can be made. Only certain users have the ability to lock and unlock scenarios and cases. Logic from a case and/or scenario can be copied and utilized in additional what-if analyses. UI allows for creating and managing multiple scenarios with various planning assumptions and business logic in a transparent and efficient manner.

See the Financial Planning Software Flow Diagram below, detailing which systems provide data and other forms of inputs to UI to create the financial plan, forecast, business analysis and other management reports. This document summarizes the systems used to produce the business plan.

Financial Planning Software Flow Diagram



Budgeting Overview

LKE uses a "bottom up" budgeting approach. The process begins with the various business units preparing detailed budgets for their individual areas of responsibility, consisting of expense items, certain types of line of business (LOB) managed revenues, and capital spending. The budgets prepared by the business units are reviewed and approved by LG&E and KU Services Officer management team. The LG&E and KU Boards ultimately approves the utilities' annual budgets. If any changes occur during the review and approval process, the changes are communicated to the appropriate 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 LOB 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. Revenue and Load Forecast

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 kilowatt hours (kWh) times the energy tariff. For demand, UI calculates base, intermediate and peak demand revenue by multiplying the kilowatt (kW) or kilovolt-ampere (kVA) times the demand tariff for base, intermediate and peak demand. For customer charge revenue, UI multiplies the number of customers times the customer charge. For base fuel revenues, UI multiplies the base fuel rate times the kilowatt 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 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

Tariff rates are entered into UI based upon the tariff book currently in effect. UI then calculates energy, demand, and customer revenues by tariff. 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 revenues are then posted to the income statement by revenue class.

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 by year.
    b. Volumetric forecasts are based on the summer and winter peaks provided and interpolated over a twelve-month period.
    c. The transmission rates are forecasted based on Attachment O of the Open Access Transmission Tariff (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. The transmission rates are forecasted based on Attachment O of the OATT.

The projected intercompany transmission revenue is imported into UI from PowerPlan based on the generation forecast provided by the Generation Planning department.

The transmission rates are documented in the LG&E and KU OATT, which is reviewed and approved by the FERC. The projected load is applied to the appropriate transmission rates to calculate the transmission revenue.

Miscellaneous Revenue

Miscellaneous revenue is comprised of:

- Forfeited discounts/late payment charges
- Reconnect charges, temporary service charges, unauthorized reconnect charges, AMI opt-out fees, gas meter and inspection charges and other service charges
- Rent from electric and gas property
- Other miscellaneous electric and gas revenues

For most of the above items, the miscellaneous revenue is calculated by utilizing recent historical trends. This data is then uploaded into UI based on the calculations done in Excel.

3. Mechanisms

Background

The Kentucky Public Service Commission (KPSC) 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 (including beneficial reuse opportunities) 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 mechanism revenue.

Demand Side Management (DSM)

DSM provides for concurrent recovery of DSM costs and provides incentive for implementing DSM programs, including lost sales 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 input in UI based 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 and the 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)

GLT provides for recovery of costs associated with replacing, installing, and repairing customers' service lines, and leak mitigation costs associated with replacing company services.

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;

Retired Asset Recovery Rider (RAR)

RAR provides for recovery of the retirement costs of generating assets, as well as other site-related assets that will not continue in use.

The RAR is a levelized 10-year revenue requirement calculated in Excel using the following:

- The projected net book value of retired generating assets at retirement including obsolete inventory
- Projected cost of removal of generating assets
- The rate of return on rate base is computed within UI using weighted average cost of debt and allowed rate of return on equity

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 Off-System Sales (OSS) electric generation, company use, line loss and unrecoverable intercompany sales. The total recoverable fuel expenses is then compared to the base fuel revenues. The over/under is booked to the FAC.

OSS

Included in a 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 FAC.

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 and Other Cost of Sales (OCOS)

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. Monthly, by unit, volumes, revenues and costs associated with off system sales, purchased power, emissions, generation, and fuel burn for the planning period are imported into UI.

Power Purchase Agreement

Power purchase agreement costs are based on the contracts set with the third-party power producers. 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 FAC and the capacity and demand costs through base rates.

Other Cost of sales (OCOS)

OCOS inputs come from PowerPlan and PROSYM. OSS, purchased power, and fuel related costs come from PROSYM, as noted above. Emissions, mechanism (DSM, ECR, Gas Supply Clause, and GLT), and transmission related costs come from PowerPlan.

OCOS includes variable production consumables used by the power plants in the generation of electricity. For coal generating units, this includes the cost of operating environmental controls and the cost of controlling coal combustion residuals (CCR). 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 / Mercury Control Chemical (Nalco) – 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

In addition to the above consumables, the power plant's also budget consumables that are variable and based on unit operations. This includes: Water Treatment Chemicals, Production Gases, Process Water Treatment Chemicals, and ELG Chemicals.

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)

O&M expenses are included as part of the Income Statement and reflect the labor and non-labor expenditures incurred and charged to the appropriate FERC account and company location. The budget is developed in a “bottom 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.

Labor Cost

The Company’s current labor base is obtained from PeopleSoft annually in May. This data is imported into PowerPlan and includes full-time and part-time regular employees and interns. It also includes data on approved open positions. The data is by employee and includes salary, position, hire date, and expenditure organization. The PowerPlan budget administrator updates tables with the wage increases, vacation hours, personal days, working days, holidays, and sick time. The budget coordinator for each expenditure organization runs a process to update the data from Peoplesoft with the data from the tables to calculate off-duty amounts and available labor hours and dollars.

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 LOBs 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 in PowerPlan.

Planned changes in costs within accounts can be specifically escalated according to contractual 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 are increased at known cost increases due to contract language, fixed amounts, or historical trend increases in costs. Non-labor expenses do not contain a general inflationary increase.

6. Property Tax

Property taxes are estimated annually based on net book asset values, including CWIP, as of December 31 of the previous year and include 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.

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.

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 contractual 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 Corporate Finance department and UI calculates the monthly expected interest income based on the temporary cash investment balance.
- Allowance for Funds Used During Construction ("AFUDC") – Calculated under both the FERC methodology and weighted average cost of capital (WACC) methodology. AFUDC is based on monthly CWIP for each project.

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
- AFUDC debt and equity adjustments

Other book/tax differences are manually input into UI. Taxable income is multiplied by the statutory federal and state income tax rates to determine current tax expense before tax credits. Estimated tax credits, such as production tax credits (PTC), investment tax credits (ITC), research and development credits (R&D), Kentucky coal and inventory credits are reviewed by the Tax department and manually input into UI. Available tax credits are then applied against the remaining current tax expense. Quarterly federal and state income tax payments are derived in UI based on current tax expense after tax credits using the jurisdiction's quarterly estimated payment option (i.e. Federal payment use annualized income method).

Deferred taxes are calculated within UI by applying the federal and state income tax rates to the same temporary book/tax differences used in the current tax calculation. Adjustments to deferred tax expense are made for excess deferred tax amortization, ITC amortization, and ITC basis reductions as provided by the Tax department. Additionally, regulatory tax asset and liability movements are derived based on these deferred tax expense adjustments as well as AFUDC equity adjustments.

9. Capital / Utility Plant

Each LOB 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 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 LOBs so that Capital decisions are made based on priorities of the company as a whole.

For projects related to AMI and New Generation AFUDC is calculated within PowerPlan and added to the capital project.

In order to import the capital budget into UI, an interface with PowerPlan containing monthly capital construction expenditures (CWIP) and cost of removal (RWIP) by utility is run. 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 Excel file from PowerPlan by plant account to determine additions to Plant in Service.

UI also imports a depreciation forecast that is calculated in Excel based on the Capital plan, including property classifications, in-service dates, retirements, and approved depreciation rates.

The approved depreciation rates[1] 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. 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 plan and the estimated in-service dates on those assets. If the asset is already in service and additional money is spent on the asset, the spend 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. <u>Dividends, Debt and Equity</u>

Dividends:

LG&E and KU (the "Utilities") pay dividends to their 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. These payout ratios may change over time.

To maintain the desired capital structure at LG&E and KU (53% equity/47% debt), LKE makes equity contributions to the Utilities or the Utilities pay extra dividends to LKE. At any time where the Utilities can pay dividends in excess of 65 percent, that amount is paid to LKE.

Capital Structure:

LG&E and KU strive to maintain a ratio of 53% equity and 47% debt. Within UI, 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.

UI calculates cash needs from operating and investing activities and issues short-term debt to fund the cash need. Short-term debt is issued until it reaches a maximum amount as prescribed by the size of the Utilities' credit capacity. The current credit facility capacity is

[1] Filed rates based on most recent depreciation study to be approved by the KPSC.

$600M at both LG&E and KU. Once short-term debt reaches a certain level near the maximum level of capacity, the short-term debt is assumed to be termed out with the issuance of long-term debt. Long-term debt is issued at a marketable size and the balancing starts again the next month. The utilities need to maintain adequate liquidity to support ongoing operations. Financial Planning works closely with the Corporate Finance team to determine efficient timing and sizing of long-term debt issuances.

On the quarter months, the model balances equity and debt to a 53:47 ratio over multiple iterations. While performing the debt to 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. Capital contributions in the form of equity from LKE are used to maintain the proper equity to debt ratios.

All short-term debt interest rates are based on a credit spread plus the one-month Term SOFR rate. For long-term debt, the rates are based on a credit spread plus the applicable tenor U.S. treasury rate. The long-term debt credit spreads are based on indicative credit spreads for the Utilities at the time interest rates were updated in UI. The forward curve as of a selected date is used to determine future Term SOFR and U.S. treasury rates for the planning period. Rates are updated on a regular basis to reflect current market conditions. .

12. <u>Pension & Postretirement</u>

Plan assumptions are evaluated by senior officers and directors, as well as 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 cost for the five-year Business Plan based on management's assumptions. These assumptions include discount rate, expected return on plan assets, expected annual wage increase, mortality base rate and mortality improvement tables, funding policy and other assumptions as needed.

The actuary's projections used in the Business Plan incorporate the 15-year amortization of gains and losses as agreed in the 2014/2015 Kentucky rate case. Additionally, the actuary provides a forecast based upon amortization of gains/loss using the Company's GAAP accounting policy. The Business Plan incorporates adjustments needed to record the difference between the 15-year amortization and the GAAP accounting amortization as a regulatory asset.

The projected pension and postretirement costs received from the actuary are summarized by company and by plan. 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, if needed, is assumed to occur annually in January while postretirement funding is assumed quarterly.

13. Other Balance Sheet assumptions

a. Balances

The last actual monthly balances from the Balance Sheets were the starting points for this forecast. The amounts were imported to UI from the G/L. A detailed and thorough balancing process is also done to ensure all details from Oracle translate appropriately into UI.

b. Leases

Beginning January 1, 2019 upon the adoption of Accounting Standards Codification (ASC) 842 Leases, all leases are recorded on the balance sheet. The monthly balance sheet amounts are obtained from the lease report obtained from the Financial Accounting and Analysis department using the PowerPlan Lease module and this is uploaded into UI from a text file.

c. Cash

As noted above, minimum cash balances are set each year at $5 million per utility. This is based on discussion with Corporate Finance and if UI determines insufficient cash balances based on the projected activity short-term debt is issued.

d. 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.

e. 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 actual December balance and is adjusted for forecasted additions and disposals.

f. Prepayments affecting the balance sheet include insurance, Information Technology (IT) contracts, advanced contract payments on transmission and distribution projects, preliminary survey payments on new generation assets, Kentucky Public Service Commission Fees (PSC), and Tennessee Valley Authority (TVA) fees.

g. 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 provided by Corporate Finance for future periods and input into UI.

h. Regulatory Assets and Liabilities

Adjustments to the regulatory assets and liabilities are obtained from schedules produced by the Company's Regulatory 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, deferred income taxes, CCR Asset Retirement Obligation (ARO) recovery, AMI and New Generation WACC regulatory asset, and RAR, 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.

i. ARO

The calculation of accretion expense is performed in an automated fashion within the PowerPlan Fixed Asset System. Accretion and depreciation expense are calculated by taking the beginning ARO liability balance multiplied by the discount rate / depreciation rate for each ARO. The ARO depreciation and accretion are recorded onto the income statement and then reclassified back into the balance sheet as a regulatory asset.

j. Accounts Payable

The material monthly balances are based on a lag utilizing capital spend and operation and maintenance expense monthly totals. Actual payables range from 15 days to 45 days from invoice date, the budget utilizes 50% of the current month and 50% of the prior month as it relates to capital spend and operation and maintenance expense monthly totals.

Electric Sales & Demand Forecast Process

PPL companies

Sales Analysis & Forecasting

April **2025**

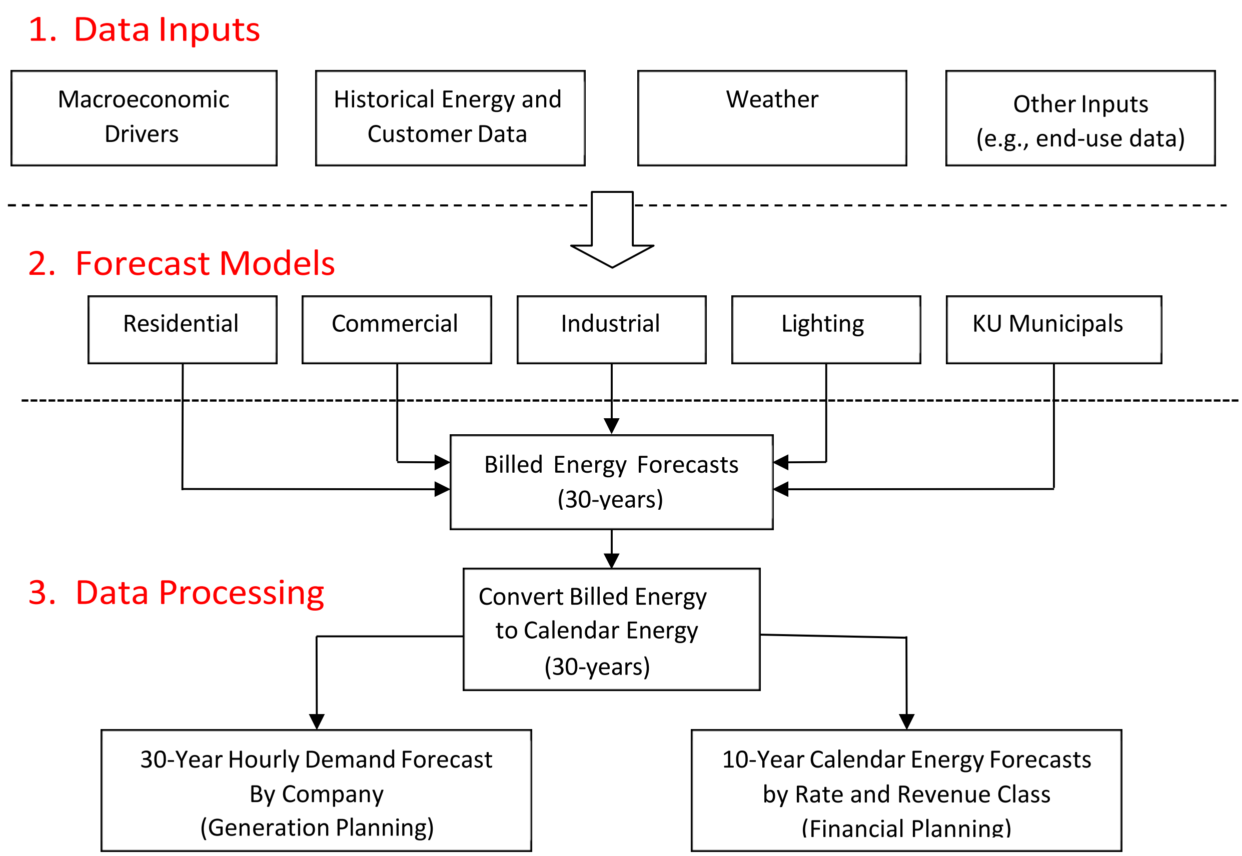
Table of Contents

1 Introduction

The Sales Analysis & Forecasting group develops the sales and demand forecasts for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). This document summarizes the processes used to produce the sales and demand forecasts.

The forecast process can be divided into three parts (see Figure 1). The first part of the forecast process involves gathering and processing input data. Key inputs to the forecast process include macroeconomic, historical energy, customer, weather, and end-use appliance shares and efficiencies data.

Figure 1: Load Forecasting Process Diagram



In the second part of the forecast process, input data is used to specify several forecast models for each company.[1] 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 monthly energy forecasts on a billed basis.[2] In the third part of the forecast process, the billed

[1] Model specification is the process of determining what variables are appropriate to include or exclude from a statistical model.
[2] Customers are assigned to one of 20 billing portions. This is discussed further in Section 7.

energy forecasts are allocated to calendar months and then to rate and revenue classes for the Financial Planning department.[3] In addition, a forecast of hourly energy requirements is developed for the Generation Planning department.[4]

At many points during the forecast process, the results are reviewed to ensure they are reasonable. For example, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. Each part of the forecast process and the software tools used to produce the forecast are discussed in more detail in the following sections.

[3] 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.
[4] Energy requirements are equal to sales plus transmission and distribution losses.

2 Software Tools

The following software packages are used in the forecast process:

1. Microsoft Office
2. R
3. SAS
4. Metrix ND (Itron)

SAS, R, and Metrix ND are used to specify forecast models. Microsoft Office is primarily used for analysis and presentations.

3 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)	S&P Global[5]	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	S&P Global	Annual or Quarterly – History and Forecast
Personal Income	S&P Global	Annual by County
Weather	National Oceanic and Atmospheric Administration (“NOAA”)	Daily HDD/CDD Data and Hourly Solar Irradiance by Weather Station – History
Billing Portion Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	Energy Information Administration (“EIA”), Itron	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, Itron	Annual – History and Forecast
Elasticities of Demand	EIA and Historical Data	Annual – History
Billed Sales History	CCS Billing System	Monthly by Service Territory and Rate Group
Number of Customers History	CCS Billing System	Monthly by Service Territory and Rate Group
Energy Requirements History	Energy Management System (“EMS”)	Hourly Energy Requirements by Company
Annual Loss Factors	2012 Loss Factor Study (by Management Applications Consulting, Inc.) and Historical Data	Annual Average Loss Factors by Company
Solar Installations	CCS Billing System, National Renewable Energy Laboratory (“NREL”), S&P Global	Monthly Net Metering and Qualifying Facility Customers, Private Solar Costs

[5] Formerly known as IHS Markit.

Electric Vehicles	S&P Global, Bloomberg New Energy Finance (“BNEF”), NREL, Electric Power Research Institute (“EPRI”), EIA, Kelley Blue Book	Monthly Cars on Road (historical), Monthly Cars on Road (forecast), Hourly EV Charging Shapes

3.1 Processing of Weather Data

Weather is a key explanatory variable in the electric forecast models. The weather dataset from NOAA’s National Climatic Data Center (“NCDC”) contains temperature (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) a historical weather series by billing period, (b) a forecast of “normal” weather by billing period.[6] Each of these processes is summarized below.

3.1.1 Historical Weather by Billing Period

The process used to create the historical weather series by billing period consists of the following steps:

1. Using historical daily weather data from the NCDC, sum the HDD and CDD values by billing portion. Each historical billing period consists of 20 portions. The Companies’ historical meter reading schedule contains the beginning and ending date for each billing portion.
2. Average the billing portion total HDDs and CDDs by billing period.

3.1.2 Normal Weather by Billing Period

The Companies’ process to produce its forecast of normal weather by billing period starts with producing a daily forecast of normal weather.[7] The Companies’ process for developing its daily forecast (summarized below in Steps 2-5) is consistent with the process the NCDC uses to create its daily normal weather forecast.[8] The Companies’ process to create its forecast of normal weather by billing period consists of six steps:

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 1st, for example, is computed as the average of the 20 January 1st temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered on the desired day. The “smoothed” normal temperature for January 1st, for example, is computed as the average of the

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[6] “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.
[7] Weather data in the electric forecast is taken from the weather stations at the Louisville Muhammad Ali International Airport (LG&E), Blue Grass Airport (KU), and Tri-Cities Airport (ODP).
[8] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

unsmoothed daily normal temperatures between December 16th and January 15th.

4. Manually adjust the values in Step 3 so that the following criteria are met:
    1. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
    2. The daily temperatures and CDDs should be generally increasing from winter to summer and generally 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. Sum the HDD and CDD values by billing portion. The Companies' forecast meter reading schedule contains the beginning and ending date for each billing portion through the end of the forecast period. Use only historical weather that has actually occurred on February 29th when billing portions include leap days.
6. Average the billing portion totals by billing period.

4 Forecast Models

LG&E and KU's electricity sales forecasts are developed primarily through econometric modeling of energy sales by rate class, but also incorporate specific intelligence on the prospective energy requirements of the utilities' largest customers. Econometric modeling captures the observed statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely accepted approach can readily accommodate the influences of national, regional, and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service.

The LG&E sales forecast comprises one jurisdiction: Kentucky-retail. The KU sales forecast comprises three jurisdictions: Kentucky-retail, Virginia-retail (served by KU in Virginia as Old Dominion Power Company, "ODP"), and FERC-wholesale.[9] Within the retail jurisdictions, the forecast typically distinguishes several classes of customers including residential, commercial, public authority, and industrial.

The econometric models used to produce the forecast must pass two critical tests. First, the explanatory variables of the models must be theoretically appropriate and widely used in electricity sales forecasting. Second, the inclusion of these explanatory variables must produce statistically significant results that lead to an intuitively reasonable forecast. In other words, the models must be theoretically and empirically robust to explain the historical behavior of the Companies' customers. These forecast models are discussed in detail in the following sections.

4.1 Residential Forecasts

The Companies develop a residential forecast for each service territory. For the KU and LG&E (also referred to herein as "LE") service territories, the residential forecast includes all customers on the Residential Service ("RS"), Residential Time of Day ("RTOD"), and Volunteer Fire Department ("VFD") rate schedules. The ODP (also referred to herein as "OD") Residential forecast includes all customers on the RS rate schedule.[9] Residential sales are forecast for each service territory as the product of a customer and a use-per-customer forecast. See Table 2 for a summary:

[9] For the purposes of this document, the KU service territory comprises KU's Kentucky-retail and FERC-wholesale jurisdictions. The ODP service territory comprises the Virginia-retail jurisdiction.

Table 2: Residential Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_RS	KU Residential Service KU Residential Time-of-Day Energy Service KU Residential Time-of-Day Demand Service KU Volunteer Fire Department	Customers, Energy, Billed Demand
LE_RS	LE Residential Service LE Residential Time-of-Day Energy Service LE Residential Time-of-Day Demand Service LE Volunteer Fire Department	Customers, Energy, Billed Demand
OD_RS	OD Residential Service	Customers, Energy

4.1.1 Residential Customer Forecasts

The number of residential customers is forecast by service territory as a function of the number of forecast households or population in the service territory. Household and population data by county and Metropolitan Statistical Area ("MSA") is available from S&P Global.

4.1.2 Residential Use-per-Customer Forecasts

Average use-per-customer is forecast using a Statistically-Adjusted End-Use ("SAE") Model. The SAE model combines econometric modeling with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating, cooling, and other equipment.

Use-per-Customer = a1*XHeat + a2*XCool + a3*XOther

Inputs for developing the heating, cooling, and other variables include weather (HDDs and CDDs), 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 more detailed discussion of each of these components and the methodology used to develop them is contained in Appendix B.

The load forecast uses EIA/Itron inputs that are projections of end-use efficiencies and adjusted electric space heating saturations over time. It is very difficult to determine which reductions in the history occurred because of DSM programs and which occurred because of customer-initiated efficiency gains. Because of this, historical data used in the residential and general service models is not adjusted for previous or current non-dispatchable demand side management and energy efficiency ("DSM-EE") programs, so the forecasts incorporate both customer-initiated energy efficiency in addition to impacts of utility DSM programs moving forward.

Through rebates, tax incentives, or credits, the Inflation Reduction Act ("IRA") is another mechanism to accelerate energy efficiency. The IRA is incorporated in the EIA/Itron projections of end-uses.

4.2 Commercial and Industrial Forecasts

Table 3 and Table 4 list the rate schedules included in the commercial and industrial forecasts. A relatively small number of the Companies' largest industrial customers account for a significant portion of total industrial sales, and any economic development opportunities, expansion, or reduction in operations by these customers can significantly impact the Companies' load forecast. Because of this, sales are forecast based on information obtained through direct discussions with these customers, their key account managers, and the economic development team. During these discussions, the customers are given the opportunity to review and comment on the usage and billed demand forecasts that the Companies create for them. This first-hand knowledge of the utilization outlook for these companies allows the Companies to directly adjust sales expectations. The following sections summarize the Companies' commercial and industrial forecasts.

Table 3: Commercial Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_GS	KU General Service single-phase service KU General Service three-phase service KU General Time-of-Day Energy single-phase service KU General Time-of-Day Energy three-phase service KU General Time-of-Day Demand single-phase service KU General Time-of-Day Demand three-phase service	Customers, Energy
LE_GS	LE General Service single-phase service LE General Service three-phase service LE General Time-of-Day Energy single-phase service LE General Time-of-Day Energy three-phase service LE General Time-of-Day Demand single-phase service LE General Time-of-Day Demand three-phase service	Customers, Energy
OD_GS	OD General Service single-phase service OD General Service three-phase service	Customers, Energy
KU_AES	KU All Electric School single-phase service KU All Electric School three-phase service	Customers, Energy
OD_SS	OD School Service[10]	Customers, Energy, Billed Demand
KU_Sec	KU Power Service Secondary KU Time-of-Day Secondary Service	Customers, Energy, Billed Demand
LE_Sec	LE Power Service Secondary LE Time-of-Day Secondary Service	Customers, Energy, Billed Demand
OD_Sec	OD Power Service Secondary OD Time-of-Day Secondary Service	Customers, Energy, Billed Demand

[10] OD School Service rate is a collection of six smaller rates, which are OD School Service General Service Single-Phase, OD School Service General Service Three-Phase, OD School Service Power Service Primary, OD School Service Power Service Secondary, OD School Service Time-of-Day Primary Service, and OD School Service Time-of-Day Secondary Service.

Table 4: Industrial Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_Pri	KU Power Service Primary KU Time-of-Day Primary Service	Customers, Energy, Billed Demand
LE_Pri	LE Power Service Primary LE Time-of-Day Primary Service	Customers, Energy, Billed Demand
OD_Ind	OD Retail Transmission Service OD Time-of-Day Primary Service	Customers, Energy, Billed Demand
OD_PS_Pri	OD Power Service Primary	Customers, Energy, Billed Demand
KU_RTS	KU Retail Transmission Service	Customers, Energy, Billed Demand
LE_RTS	LE Retail Transmission Service	Customers, Energy, Billed Demand
KU_FLS	KU Fluctuating Load Service	Customers, Energy, Billed Demand
OD_FWP	OD Water Pumping Service	Customers, Energy

4.2.1 General Service Forecasts

The general service forecasts include all customers on the GS rate schedule. For each service territory, GS forecasts employ an SAE model like the model used to forecast residential use-per- customer. The main difference between the GS and RS forecast is that the GS model forecasts total sales (rather than use-per-customer) as a function of energy used by heating, cooling, and other equipment, as well as binary variables to account for anomalies in the historical data.[11] A more detailed discussion of this model is included in Appendix A.

As discussed in the Residential UPC forecast (Section 4.1.2), commercial end-use inputs incorporate impacts of the IRA. There were no space heating adjustments for commercial customers.

4.2.2 KU Secondary Forecast

The KU Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, end-use intensity projections, and binary variables that account for anomalies in the historical data.

4.2.3 KU All-Electric School Forecast

The KU All-Electric School forecast includes all customers on the AES rate schedule. Sales to these customers are modeled as a function of end-use intensity projections, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.

4.2.4 ODP School Service Forecast

The ODP School Service forecast includes all customers on the SS rate schedule. Sales to these customers

[11] A binary variable is a variable that can only take on two possible values, e.g., 0 and 1. Coding historically anomalous data using a binary variable allows it to be excluded from modeling, which improves model specification and thus model predictions. For example, in some models, the periods affected by the Covid-19 pandemic are coded as “1” and unaffected periods are coded as “0.” This coding effectively removes the significant impact of Covid-19 in a few historical months.

are modeled as a function of a constant, a variable to capture energy efficiency trends, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.

4.2.5 LG&E Secondary Forecast

The LG&E Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, economic variables, end-use intensity projections, and other binary variables to account for anomalies in the historical data.

4.2.6 LG&E Special Contract Forecast

LG&E has one customer that is served under a special contract. This customer's consumption is forecast separately based on information obtained through direct discussions with the customer.

4.2.7 ODP Secondary Forecast

The ODP Secondary forecast includes customers on the Power Service Secondary and Time-of-Day Secondary rate schedules. Sales to these customers are modeled as a function of energy used by heating equipment, cooling equipment, and other equipment as well as economic variables and other binary variables to account for anomalies in the historical data.

4.2.8 ODP Municipal Pumping Forecast

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. Sales to these customers are modeled using a trend based on recent sales.

4.2.9 KU Primary Forecast

The KU Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an economic variable, monthly binaries, and a binary variable to capture Covid-related usage changes. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers in these rate classes that are forecast individually based on information obtained through direct discussions with these customers.

4.2.10 KU Retail Transmission Service Forecast

The KU Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for several large KU RTS customers are forecast individually based on information obtained through direct discussions with these customers. The majority of the remaining RTS customers are mining customers. Sales to these customers are modeled as a function of a mining index, an economic variable, a lag dependent variable, and a binary variable to capture Covid-related usage changes.

4.2.11 KU Fluctuating Load Service Forecast

The KU Fluctuating Load Service forecast includes the one customer on the FLS rate schedule and is developed based on information obtained through direct discussions with this customer.

4.2.12 LG&E Primary Forecast

The LG&E Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an economic variable and monthly binaries. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers on these rate schedules that are forecast individually based on information obtained through direct discussions with these customers.

4.2.13 LG&E Retail Transmission Service Forecast

The LG&E Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for several large LG&E RTS customers are forecast individually based on information obtained through direct discussions with these customers. Sales to the remaining customers are modeled as a function of historical monthly usage.

4.2.14 ODP Industrial Forecast

The ODP industrial forecast includes all customers receiving primary service on the PS rate schedule as well as customers receiving service on the TODP or RTS rate schedules. ODP industrial sales are modeled as a function of mining production forecasts and a weather variable.

4.3 KU Municipal Forecasts

KU's municipal customers develop their own sales forecasts. These forecasts are reviewed by KU for consistency and compared to historical sales trends. KU directs questions, concerns, and potential revisions to the municipal customers. See Table 5 for a summary:

Table 5: KU Municipal Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_MuniPri	KU Wholesale (Bardstown)	Energy, Billed Demand
KU_MuniTran	KU Wholesale (Nicholasville)	Energy, Billed Demand

4.4 Lighting and EV Charging Forecasts

The Lighting and EV Charging forecasts include customers receiving service on the following rate schedules in Table 6:

Table 6: Lighting and EV Charging Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_EV Fast Charging	KU Electric Vehicle Fast Charging Service	Energy
KU_EV Charging	KU Electric Vehicle Charging Service	Energy
KU_LES	KU Lighting Energy Service	Energy
KU_OSL	KU Outdoor Sports Lighting Service	Customers, Energy, Billed Demand
KU_TES	KU Traffic Energy Service	Customers, Energy
KU_UM	KU Unmetered Lighting Service	Customers
LE_EV Fast Charging	LE Electric Vehicle Fast Charging Service	Energy
LE_EV Charging	LE Electric Vehicle Charging Service	Energy
LE_LES	LE Lighting Energy Service	Energy
LE_OSL	LE Outdoor Sports Lighting Service	Customers, Energy, Billed Demand
LE_TES	LE Traffic Energy Service	Customers, Energy
LE_UM	LE Unmetered Lighting Service	Customers
OD_UM	OD Unmetered Lighting Service	Customers

All Lighting and EV Charging energy is modeled using a trend based on recent sales.

4.5 Distributed Solar Generation Forecast

The net metering distributed solar generation forecast is based on a consumer choice model. The consumer choice model is driven by various economic and financial inputs, including the retail price for electricity, the levelized cost of energy ("LCOE") for solar installations, disposable personal income, monthly binaries, and the price paid for energy exported to the grid. The changes to the timing of the solar investment tax credit ("ITC") phase-out discussed in the IRA is included in the LCOE variable in this model. Two models are specified using the above variables to create both a near- term and a long-term model. This forecast is a blend of the output of these two models.

In addition to net metering, there is also a forecast of behind-the-meter ("BTM") qualifying facilities ("QF") customers. This forecast contemplates only BTM QF and not independent or merchant generators that may locate to the area. This model is based upon the historical trend in BTM QF adoptions as well as current capacity-per-installation levels.

For purposes of revenue forecasting, the reduced sales attributable to distributed generation are allocated by rate as a reduction to the respective rate forecasts. The hourly distributed generation forecast, which is represented as negative load, is added on top of the mid load forecast hourly shape discussed in Section 5.2.

4.6 Electric Vehicle Forecast

The electric vehicle forecast is based on a consumer choice model. The consumer choice model is driven by the cost difference between electric vehicles and internal combustion engine vehicles. The forecast assumes the tax credits discussed in the IRA. Consistent with previous filings, efficiency and miles driven assumptions are used to translate the vehicles-in-operation into an energy impact and that impact is allocated entirely to the Residential class.

For purposes of revenue forecasting, the EV sales forecast is allocated as an increase to the RS forecasts. The EV hourly profile, which assumes managed charging, is added on top of the mid load forecast hourly profile discussed in Section 5.2.

An additional, positive adjustment was made to account for National Electric Vehicle Infrastructure ("NEVI") funds that were discussed in the Infrastructure Investment and Jobs Act ("IIJA"). The forecast assumes EV fast chargers will locate in the service territory beginning in 2023 because of this legislation and grow over time. The TODS rates for LG&E and KU receive the adjustments. By 2028, these chargers are only forecast to add 2 GWh of load annually.

4.7 Advanced Metering Infrastructure ("AMI") Benefits

The forecast has two adjustments to account for the benefits AMI is anticipated to provide in terms of load reduction. These adjustments reduce load.

4.7.1 Conservation Voltage Reduction ("CVR")

CVR adjustments are phased in over time as AMI meters are deployed and the necessary distribution controls are installed. Beginning in 2030, the combined CVR adjustments reduce annual load by 205 GWh annually. Specifically, CVR reduces RS and GS sales. The adjustments are consistent with what was discussed in Exhibit LEB-3 in Case Nos. 2020-00349 and 2020- 00350.

4.7.2 AMI ePortal Savings

AMI ePortal savings are allocated to customers on rates that do not currently have access to interval data. This primarily includes RS, GS, KU AES, ODP SS, and PS rates. These are phased in as AMI meters are deployed and represent 0.35% of monthly sales reductions for the applicable rates upon full deployment. The adjustments are consistent with what was discussed in Exhibit LEB-3 in Case Nos. 2020-00349 and 2020-00350.

4.8 Billed Demand Forecasts

For most rates, regression models are developed to forecast billed demands primarily as a function of energy. For some rates, billed demand forecasts are developed by applying historical ratios of billed demand and energy to the energy forecast. For a given customer and month, tariff provisions can impact the relationship between billed demands and energy. For example, the base demand for a TODP customer is computed as the greater of several factors including the customer’s contract capacity and highest measured demand for the preceding 11 billing periods. The Companies’ forecasting process considers the potential impact of these factors on the overall forecasts. Base, peak, and intermediate demands for the Companies’ largest customers are developed with input from the customer.

5 Data Processing

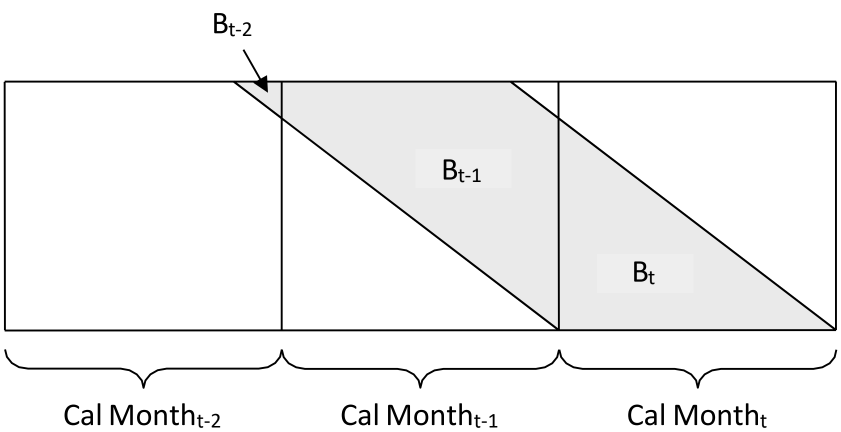
All customers are assigned to one of 20 billing portions. A billing portion determines what day of the month, generally, a customer's meter is read. Most customers' monthly bills include energy that was consumed in portions of more than one calendar month. This energy is referred to as "billed" energy and the majority of the Companies' forecast models are initially specified to forecast "billed" sales. The following processes are completed to prepare the forecasts for use as inputs to the Companies' revenue and generation forecasts:

- Billed-to-Calendar Energy Conversion
- Hourly Energy Requirements Forecast

5.1 Billed-to-Calendar Energy Conversion

Most forecast volumes must be converted from a billed to calendar basis to meet the needs of the Financial Planning department. The shaded area in Figure 2 represents a typical billing period (B). Area B_t represents the portion of billed energy consumed in the current calendar month (Cal $Month_t$). Area B_{t-1} represents the portion of billed energy consumed in the previous calendar month (Cal $Month_{t-1}$). Area B_{t-2} represents the portion of billed energy consumed in the calendar month two months prior to the current month (Cal $Month_{t-2}$). Not all billing periods include volumes that were consumed in the calendar month two months prior to the current month.

Figure 2: Billed and Calendar Energy



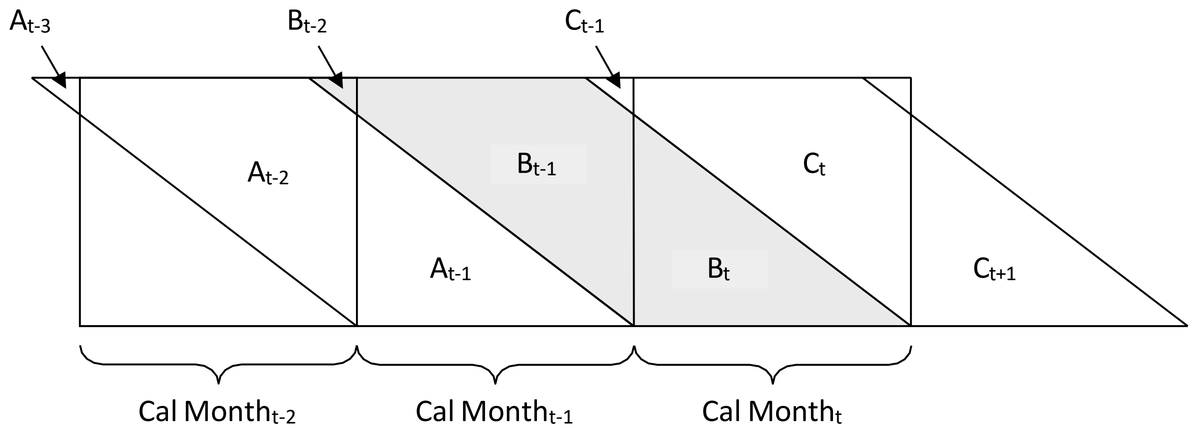
In this process, billed energy is allocated to calendar months based on when the energy is consumed. Furthermore, the weather-sensitive portion of the billed energy forecast is allocated to calendar months based on degree days (HDDs and CDDs) and the non-weather-sensitive portion is allocated based on billing days.[12] For example, the June billing period includes portions of June, May, and possibly April. Under normal weather conditions, June will have more CDDs than May. Therefore, a greater portion of the weather-

[12] For a given billing period, the number of degree days and billing days in each calendar month is computed as an average over the 20 billing portions.

sensitive energy in the June billing period will be allocated to the calendar month of June.

Figure 3 contains two additional billing periods (A & C). Calendar sales for Cal Month$_{t-1}$ is equal to the sum of energy in in billing period segments A_{t-1}, B_{t-1}, and C_{t-1}.

Figure 3 – Billed and Calendar Energy



5.2 Hourly Energy Requirements Forecast

5.2.1 Normal Hourly Energy Requirements Forecast

The Generation Planning department uses the hourly energy requirements forecast to develop resource expansion plans and a forecast of generation production costs. An hourly energy requirements forecast is developed for each company by adding losses to calendar-month sales and allocating the sum to hours in each month. The result reflects customers' hourly energy requirements under normal weather conditions. The following process is used to develop this forecast:

1. Sum calendar-month forecast volumes independent of distributed generation and incremental EV load by company. Then, add transmission and distribution losses as well as incremental company uses to compute monthly energy requirements. The sum of calendar-month forecast volumes for KU includes forecast volumes for the KU and ODP service territories.
2. Develop normalized load duration curves for each company and month based on 10 years of historical hourly energy requirements. For KU, to model the impact of the municipal departure, this process is completed based on historical energy requirements where the impact of the departing municipals has been removed.
3. Compute the ratio of hourly energy requirements and monthly energy requirements for each hour and company. Rank the ratios in each month from highest to lowest. The normalized load duration curves are computed by averaging the ratios by month, rank, and company.
    1. The winter and summer peak can occur in multiple months, and the predicted peak for a season (meaning winter or summer) is higher than the predicted peak for any individual month within the season. For this reason, the normalized load duration curves for January and August are adjusted to match peaks produced in separate seasonal models. This process produces seasonal peak demand forecasts that are placed within January (winter) and August (summer).

4. Allocate total forecast monthly energy requirements by company to hours using the normalized load duration curves. For KU, the normalized load durations curves reflect the municipal departure.
5. Assign hourly energy requirements to specific hours in each month based on the ordering of days and weekends in the month. Historical reference years and months having matching calendar profiles as the forecast month (e.g., a historical August that begins on a Tuesday) are selected to be used for ordering purposes only.
6. Adjust the hourly energy requirements forecast to reflect the hourly forecast impact of distributed solar generation, electric vehicle, and other inputs having distinct load shapes. Said differently, the profiles attributable to solar, electric vehicles, and economic development are layered in separately. The solar profiles are developed to ensure that the underlying weather and solar irradiance align. Consistent with prior forecasts, EV managed charging is assumed for the hourly shape.

5.2.2 Weather-Year Forecasts

The Companies develop their hourly energy requirements forecast with the assumption that weather will be average or “normal” in every year (see discussion above in Section 5.2.1). While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason, to support the Companies’ Reserve Margin Analysis and other studies focused on generation reliability, the Companies produce 51 hourly energy requirement forecasts for each year of the forecast based on actual weather in each of the last 51 years (1973 through 2023).

To create these “weather year” forecasts, the Companies develop a model to forecast hourly energy requirements as a function of temperature and calendar variables such as day of week and holidays. This model is used to forecast hourly energy requirements in each year of the forecast period based on hourly temperatures from the prior 51 calendar years but using calendar variables from the forecast period. The Companies produce two version of this analysis; a version where the forecast years are all identically shaped from a calendar perspective (i.e. all years start on a Sunday and leap days are excluded), and a version where forecast years match the calendar as it actually occurs. These two versions rely on identical modeling and weather but are used for different purposes. The former version allows for a consistent load distribution across multiple years and is useful for analysis such as assessing reserve margin requirements, while the latter allows for accurate assessment of weather likelihood and is useful for analysis of minimum fuel burn requirements and outage planning. To ensure consistency with the Companies’ energy forecast, the following steps are taken once the model outputs are available:

1. All hours of the weather year forecast are adjusted so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the mid energy forecast excluding those inputs having distinct load shapes.
2. Extreme points in the historical data are reviewed individually to ensure model predictions are reasonable based on recent experiences and knowledge of the Company's system load response. These points can be increased or decreased incrementally as appropriate.
3. At this point, inputs having distinct load shapes are added (or subtracted) on an hourly basis. These include EV charging, distributed generation, and new major accounts.
    a. The hourly distributed generation profiles are layered in according to each weather year. For historical years for which we have solar irradiance data (since 1998), the distributed generation profile matches that year’s weather profile. For prior years, the distributed

generation profile represents an average irradiance of the years that are available.

4. All hours of the weather year forecast are again adjusted, but this time so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the mid energy forecast including those load forecast inputs having distinct load shapes.
5. The mean of the seasonal peaks of the weather years are then adjusted to match the seasonal peaks forecast using normal weather.[13]
6. Finally, all hours of the weather year forecast are adjusted so that the mean of seasonal energy requirements from the weather year forecasts equals seasonal energy requirements in the mid energy forecast, which include those load forecast inputs having distinct load shapes.

[13] Seasons are defined as winter (November, December, January, February), summer (June, July, August, September), and shoulder (March, April, May, October) in this context.

6 Review

In addition to assessing the reasonableness of models (discussed in introduction to Section 4), forecast results are visually inspected versus recent history and prior forecasts to ensure reasonableness of results. Because of the obligation to serve load in every hour, the Companies ensure monthly and hourly profiles are reasonable. To accomplish this, the new forecast is compared to (i) the previous forecast, (ii) weather-normalized actual sales for the comparable period in prior years, (iii) a range of historical actual sales and energy requirements, and (iv) the end-use projections assumed in the forecast models. This process ensures that the forecast is consistent with recent trends in the way customers are using electricity today and how that could change in the future.

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 can incorporate the end-use factors driving energy use. By including end-use structure in 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 section 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 2020 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Model 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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, 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 Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating intensity,
- 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,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (*y*) and month (*m*)
- $HeatIndex_{y,m}$ is the annual index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is composed of electric space heating intensity. The index will change over time with changes in heating intensity. Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{13} \times \frac{(HeatIntensity_y)}{(HeatIntensity_{13})} \tag{4}$$

In this expression, 2013 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than 1.0 if intensity levels are above their 2013 level.

$$HeatSales_{13} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{13}}{\sum_e {}^{kWh}/_{Sqft_e}}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2013 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, and prices. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{13}}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \quad \times \left(\frac{Price_{y,m}}{Price_{13}}\right)^{-0.18} \tag{6}$$

Where

- *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 2013,
- *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 (2013). The first terms, which involve heating degree days, serves 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 intensity,
- 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:

$$CoolIndex_y = CoolSales_{13} \times \frac{\left({CoolShare_y}/{Eff_y}\right)}{\left({CoolShare_{13}}/{Eff_{13}}\right)} \tag{8}$$

Data values in 2013 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2013 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.

$$CoolSales_{13} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{13}}{\sum_e {kWh}/{Sqft_e}}\right) \quad (9)$$

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 2013 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:

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{13}}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \times \left(\frac{Price_{y,m}}{Price_{13}}\right)^{-0.18} \quad (10)$$

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 2013.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2013). 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 intensities,
- 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:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \quad (11)$$

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:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{13}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{13}^{Type} / Eff_{13}^{Type}} \right) \quad (12)$$

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.

$$Weight_{13}^{Type} = \left(\frac{kWh}{Sqft}\right)_{Type} \times \left(\frac{CommercialSales_{13}}{\sum_e {}^{kWh}/_{Sqft_e}} \right) \quad (13)$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end-uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \times \left(\frac{Price_{y.m}}{Price_{13}}\right)^{-0.18} \quad (14)$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

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

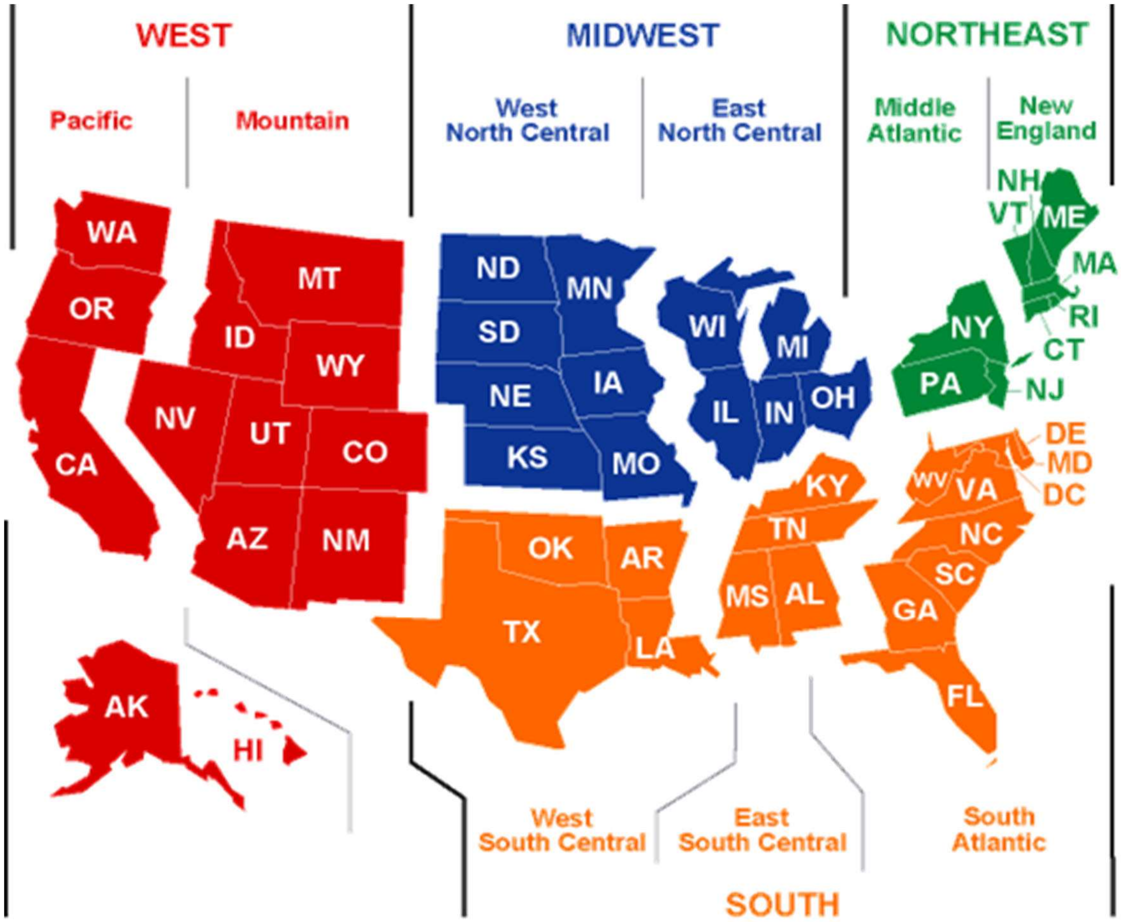


Table 1: List of SAE Electric Files

Spreadsheets	*MetrixND* Project Files
NewEnglandCom23.xlsx	NewEnglandCom23.ndm
MiddleAtlanticCom23.xlsx	MiddleAtlanticCom23.ndm
EastNorthCentralCom23.xlsx	EastNorthCentralCom23.ndm
WestNorthCentralCom23.xlsx	WestNorthCentralCom23.ndm
SouthAtlanticCom23.xlsx	SouthAltanticCom23.ndm
EastSouthCentralCom23.xlsx	EastSouthCentralCom23.ndm
WestSouthCentralCom23.xlsx	WestSouthCentralCom23.ndm
MountainCom23.xlsx	MountainCom23.ndm
PacificCom23.xlsx	PacificCom23.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.

- **EIAData** contains the raw forecasted data provided by the EIA.
- **BaseYrInput** 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** contains historical and forecasted end-use equipment efficiency trends. The forecasted values are based on projections provided by the EIA.
- **Shares** contains historical and forecasted end-use saturations.
- **Intensity** contains the annual intensity (kWh/sqft) projections by end use.
- **AnnualIndices** contains the annual *Heat*, *Cool* and *Other* equipment indices.
- **FloorSpace** contains the annual floor space (sqft) projections by end use.
- **PV** incorporates the impact of photovoltaic batteries into the forecast.
- **Graphs** contains graphs of Efficiency and Intensities, which can be updating by selecting from the list in cell B2.

The MetrixND project files contain the following objects.

Parameter Tables

- **Parameters.** This parameter table includes the values of the annual HDD and CDD in 2013 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 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. 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 can incorporate the end-use factors driving energy use. By including end-use structure in 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 residential SAE spreadsheets is the 2020 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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, 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:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{15}^{Type} \big/ Eff_{15}^{Type} \right)} \tag{4}$$

The $StructuralIndex$ is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2015 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{15} \times SurfaceArea_{15}} \tag{5}$$

The $StructuralIndex$ is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2015 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2015. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2015 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times HeatShare_{15}^{Type} \qquad (7)$$

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 2015 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	916
Electric Space Heating Heat Pump	346

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:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} \Big/ Eff_{15}^{Type}\right)} \times$$
$$\left(TenYearMovingAverageElectric\,\mathrm{Pr}\,i\,ce_{y,m}\right)^{\varphi} \times \left(TenYearMovingAverageGas\,\mathrm{Pr}\,i\,ce_{y,m}\right)^{\gamma} \qquad (8)$$

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:

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{15}}\right) \times \left(\frac{HHSize_y}{HHSize_{15}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{15}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{15,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{15,7}}\right)^{\kappa} \quad (9)$$

Where:

- $WgtHDD$ 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 2015
- $HHSize$ 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 (2015). 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,

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

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:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} \big/ Eff_{15}^{Type}\right)} \qquad (11)$$

Data values in 2015 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2015. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2015 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times CoolShare_{15}^{Type} \qquad (12)$$

In the SAE spreadsheets, these weights are referred to as Intensities and are defined on the *EIAData* tab. With these weights, the $CoolIndex$ value in 2015 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	1,012
Space Cooling Heat Pump	306
Room Air Conditioning	277

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.

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{15}^{Type} \Big/ Eff_{15}^{Type} \right)} \times$$
$$(TenYearMovingAverageElectric\,Price_{y,m})^{\varphi} \times (TenYearMovingAverageGas\,Price_{y,m})^{\gamma} \quad (13)$$

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:

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{15}}\right) \times \left(\frac{HHSize_y}{HHSize_{15}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{15}}\right)^{0.20} \times$$
$$\left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{15}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{15}}\right)^{\kappa} \quad (14)$$

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 2015.

By construction, the $CoolUse$ variable has an annual sum that is close to 1.0 in the base year (2015). 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.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{15}^{Type} \Big/ \frac{1}{UEC_{15}^{Type}} \right)} \times MoMult_m^{Type} \times$$
$$(TenYearMovingAverageElectric\,Price)^{\lambda} \times$$
$$(TenYearMovingAverageGas\,Price)^{\kappa} \tag{16}$$

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:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{HHSize_y}{HHSize_{15}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{15}}\right)^{0.10} \times$$
$$\left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{15}}\right)^{\varphi} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{15}}\right)^{\lambda} \tag{17}$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (18)$$

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in **Figure 16**. 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 16: Mapping of States to Census Divisions

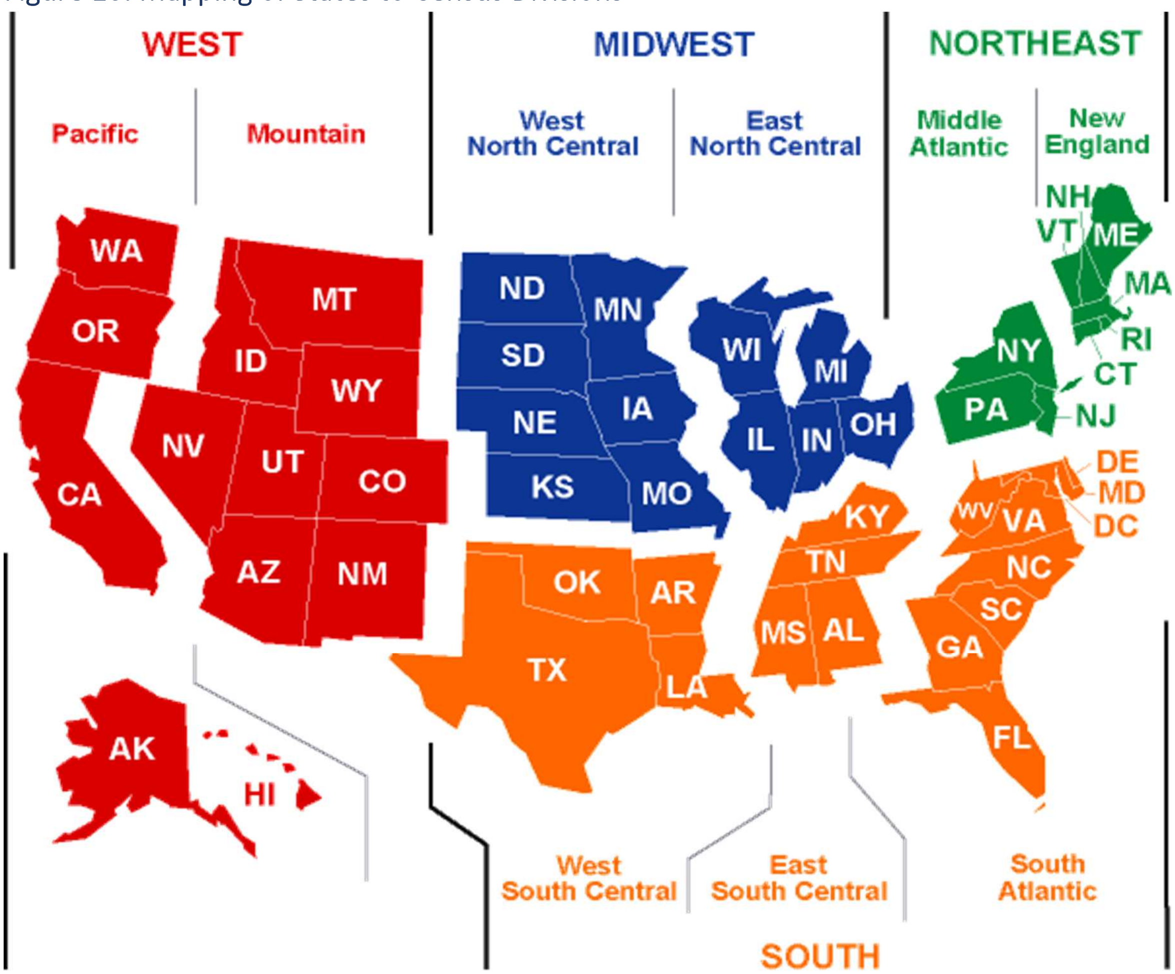


Table 3: List of SAE Files

Spreadsheet	MetrixND Project File
NewEngland.xlsx	SAE_NewEngland.ndm
MiddleAtlantic.xlsx	SAE_MiddleAtlantic.ndm
EastNorthCentral.xlsx	SAE_EastNorthCentral.ndm
WestNorthCentral.xlsx	SAE_WestNorthCentral.ndm
SouthAtlantic.xlsx	SAE_SouthAltantic.ndm
EastSouthCentral.xlsx	SAE_EastSouthCentral.ndm
WestSouthCentral.xlsx	SAE_WestSouthCentral.ndm
Mountain.xlsx	SAE_Mountain.ndm
Pacific.xlsx	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 link to the data in these spreadsheets. These project files calculate the end-use Usage variables are constructed and the estimated SAE models.

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** 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** contains a worksheet for incorporating electric vehicle (EV) impacts.
- **PV** contains a 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** links to the *AnnualIndices* tab for heating and cooling indices, and *ShareUEC* tab for water heating, lighting, and appliances in the SAE spreadsheet.
- **UtilityData** is a linkless data table that contains sales, price, economic and weather data specific to a given Census Division.
- **MonthlyMults** links to the corresponding tab in the SAE spreadsheet.

Transformation Tables

- **EconTrans** computes the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans** computes the HDD and CDD indices used in the usage equations.
- **ResidentialVars** computes the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars** computes the calendar binary variables that could be required in the regression model.
- **AnnualFcst** computes the annual historical and forecast sales and annual change in sales.
- **EndUseFcst** computes the monthly sales forecasts by end uses.

Models

- **ResModel** is the Statistically Adjusted End-Use Model.

Steps to Customize the Files for Your Service Territory

The files that are distributed along with this document 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 "B9", 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

Further Customization of Starting Usage Levels

In addition to the minimum steps listed above, you can also utilize model-based calibration process described previously to further fine-tune starting year usage estimates to your service territory.

Customizing the End-use Share Paths

You can also 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.

2025BP Electric Sales and Demands

Sales Analysis and Forecasting
July 12, 2024

LG&E KU
PPL companies

Forecast Summary

- May 2024 YTD weather-normalized billed sales*
  - 2.2% higher than May 2023 YTD weather-normalized sales
  - 0.4% above 2024BP on strong GS and Commercial sales
- 2025BP Billed Sales (vs. 2024BP)
  - Mostly unchanged in near-term; higher long-term on economic development load growth
    - 0.6% lower balance of year on slower commissioning of BOSK Phase 1
    - 0.9% higher in 2026 due to GS and KU Economic Development ("Econ Dev")
    - 8.6% higher in 2029 as LG&E Economic Development more than offsets indefinite delay of BOSK Phase 2
- 2025BP Billed Demands (vs. 2024BP)
  - KW demands mostly unchanged; KVA demands follow Major Account and Economic Development load growth
- Customer forecast is slightly higher than 2024BP in BP period

*All references to sales in this presentation refer to billing period sales and include impacts of EV and Distributed Generation

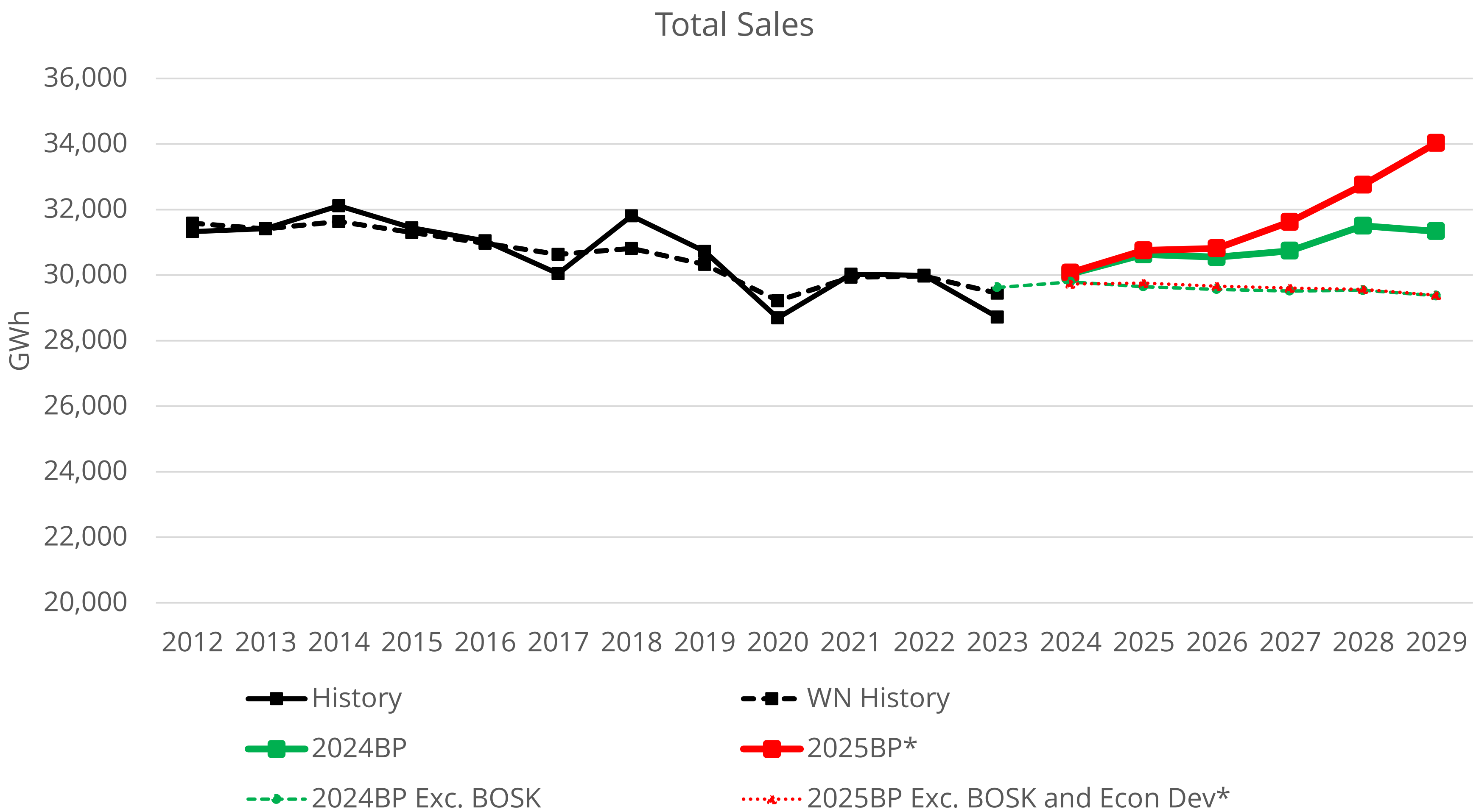
Other Forecast Notes

- Higher 2025BP distributed solar forecast reflects impact of EPA Solar-for-All program through 2030; KY installed net metering capacity reaches 1% of peak in late 2025, slightly earlier than 2024BP
  - 2029 Impact: nearly 91 GWh of load reduction
  - Like 2024BP, distributed solar continues to grow after 1% NM cap through smaller installations
- EV forecast marginally higher in near-term vs. 2024BP
  - About 38K projected cars on road by end of 2029
- Other assumptions consistent with 2024BP
  - CVR reduces sales beginning in 2026 (approximately 164 GWh by 2029)
  - AMI e-portal energy savings are 57 GWh by 2029
  - 2025BP reflects impact of IRA and the company's DSM programs
  - Per IIJA/NEVI bill, new interstate charging load beginning this year

Billed Sales

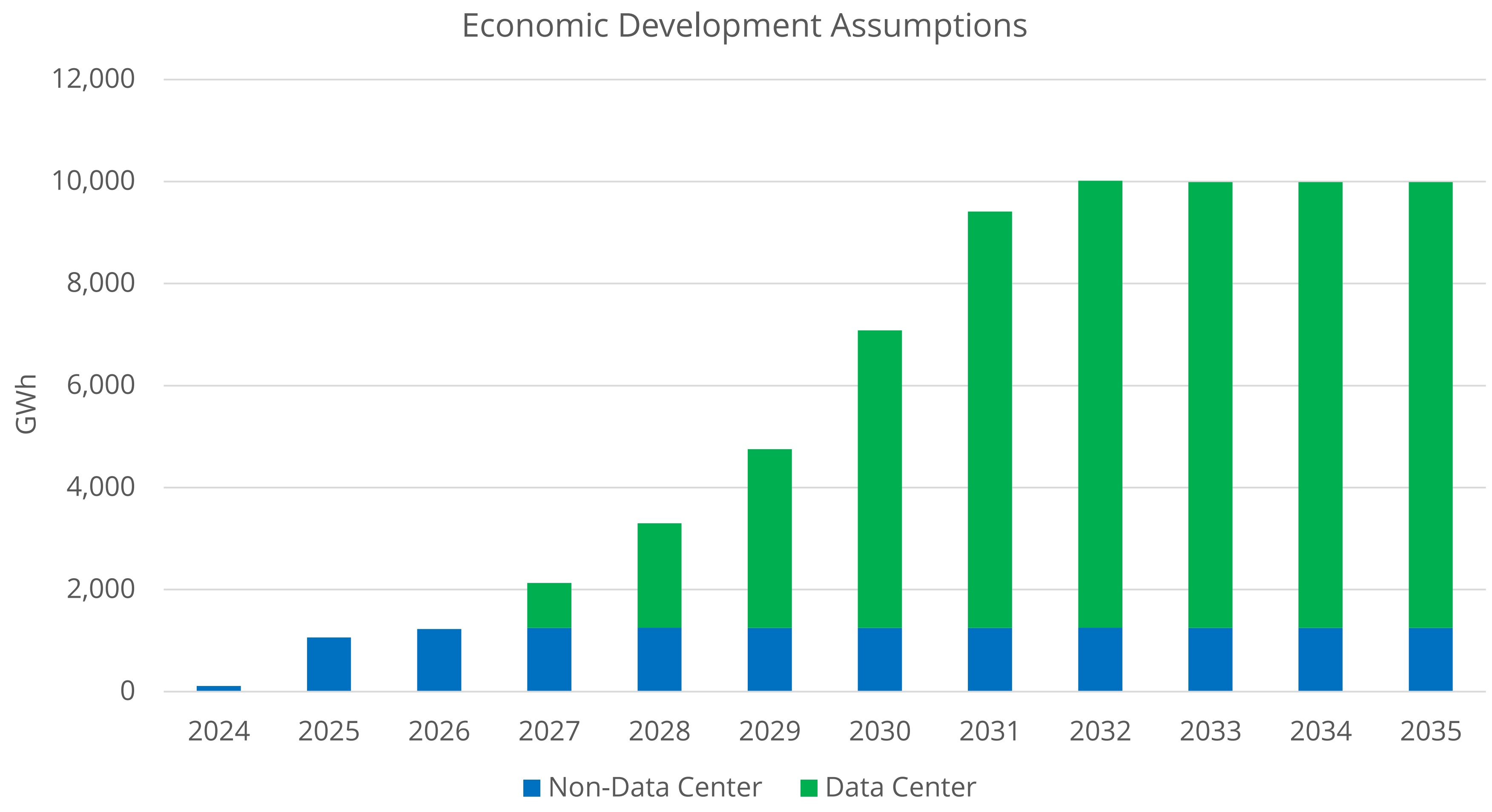
PPL companies

Total sales 0.4% higher in 2025; major accounts and economic development drive growth thereafter



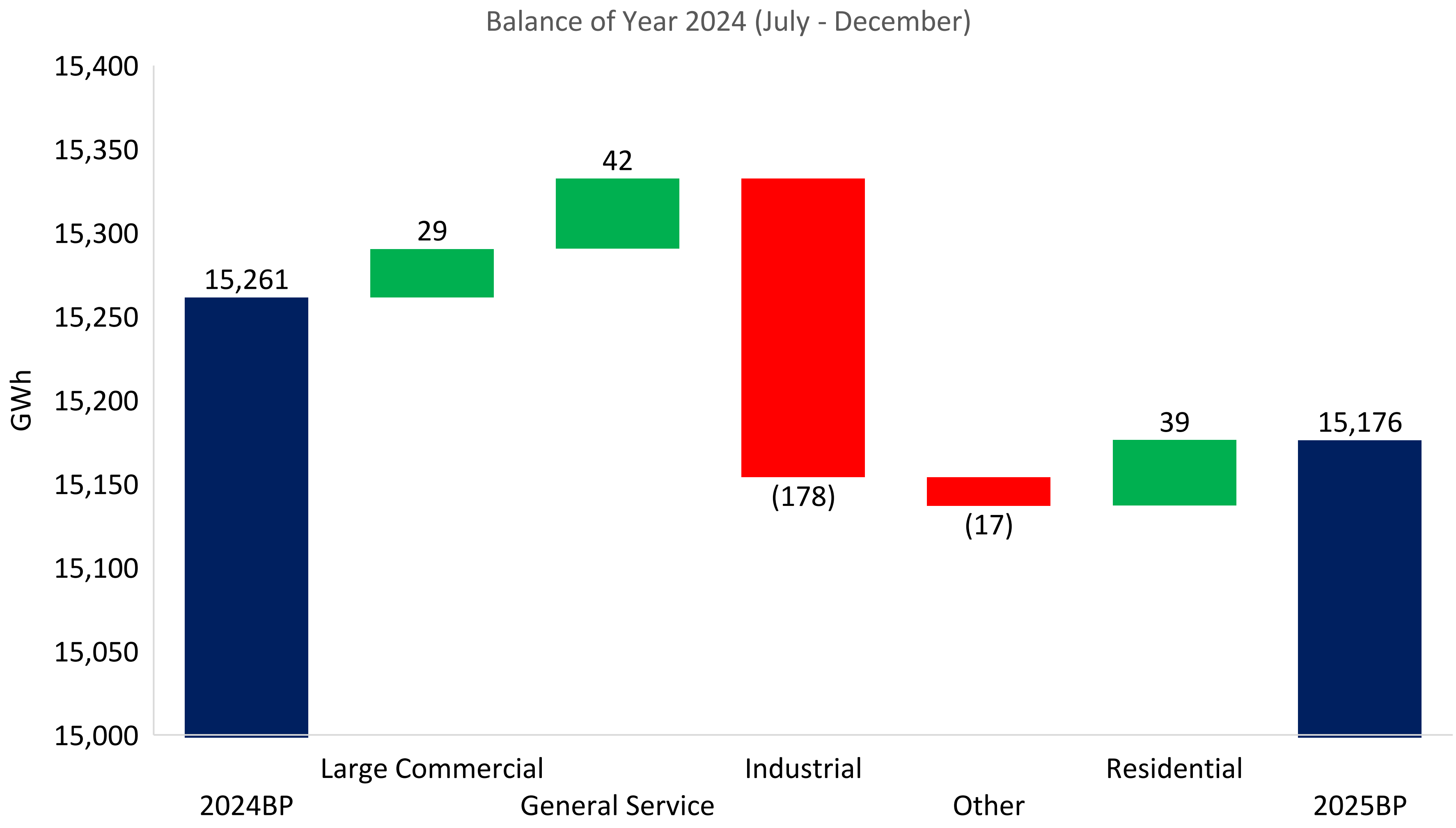
*2024 is 5 months of actuals and 7 months of forecast.

Magnitude and timing of data center projects and major account expansions are key uncertainties

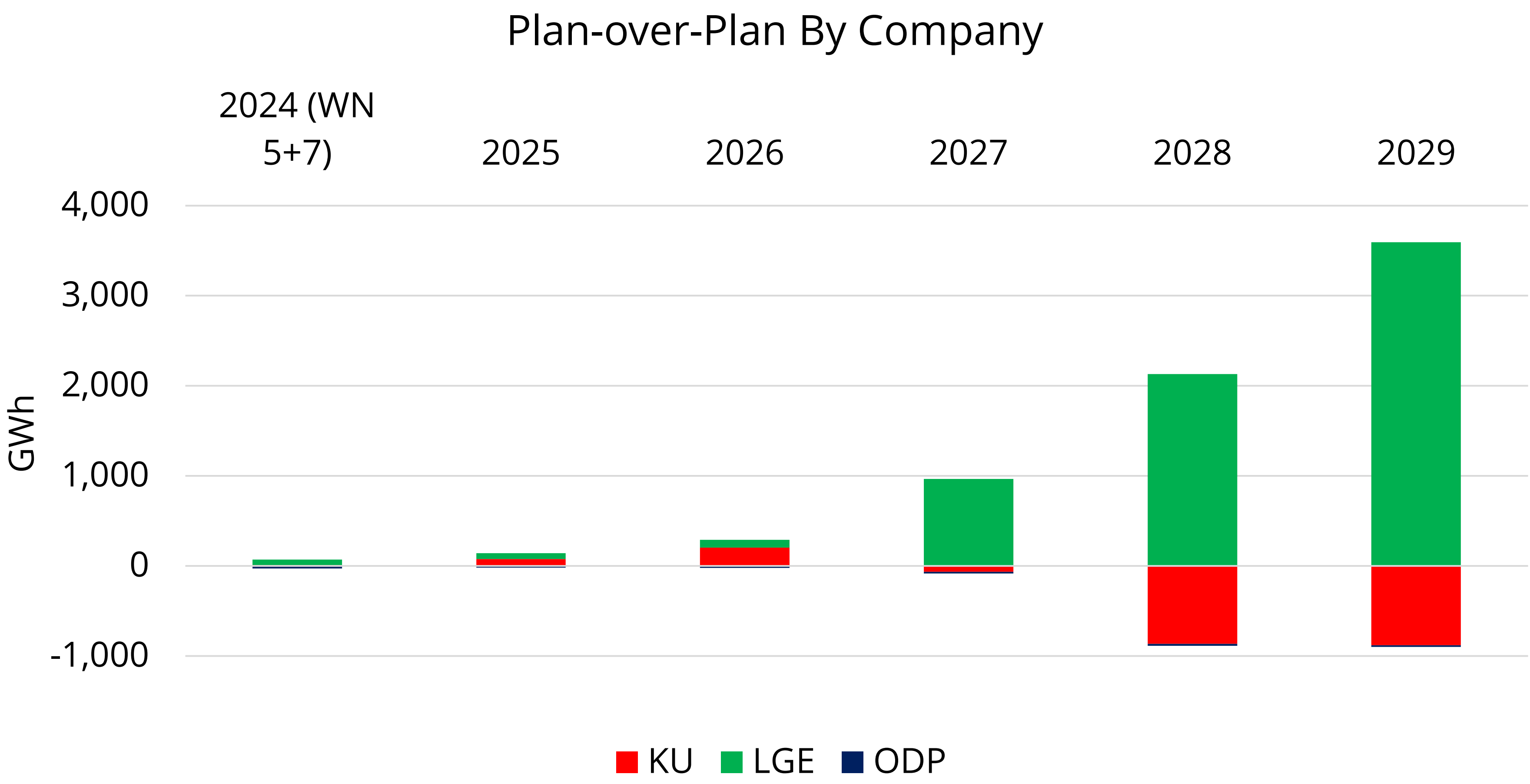


Business Use

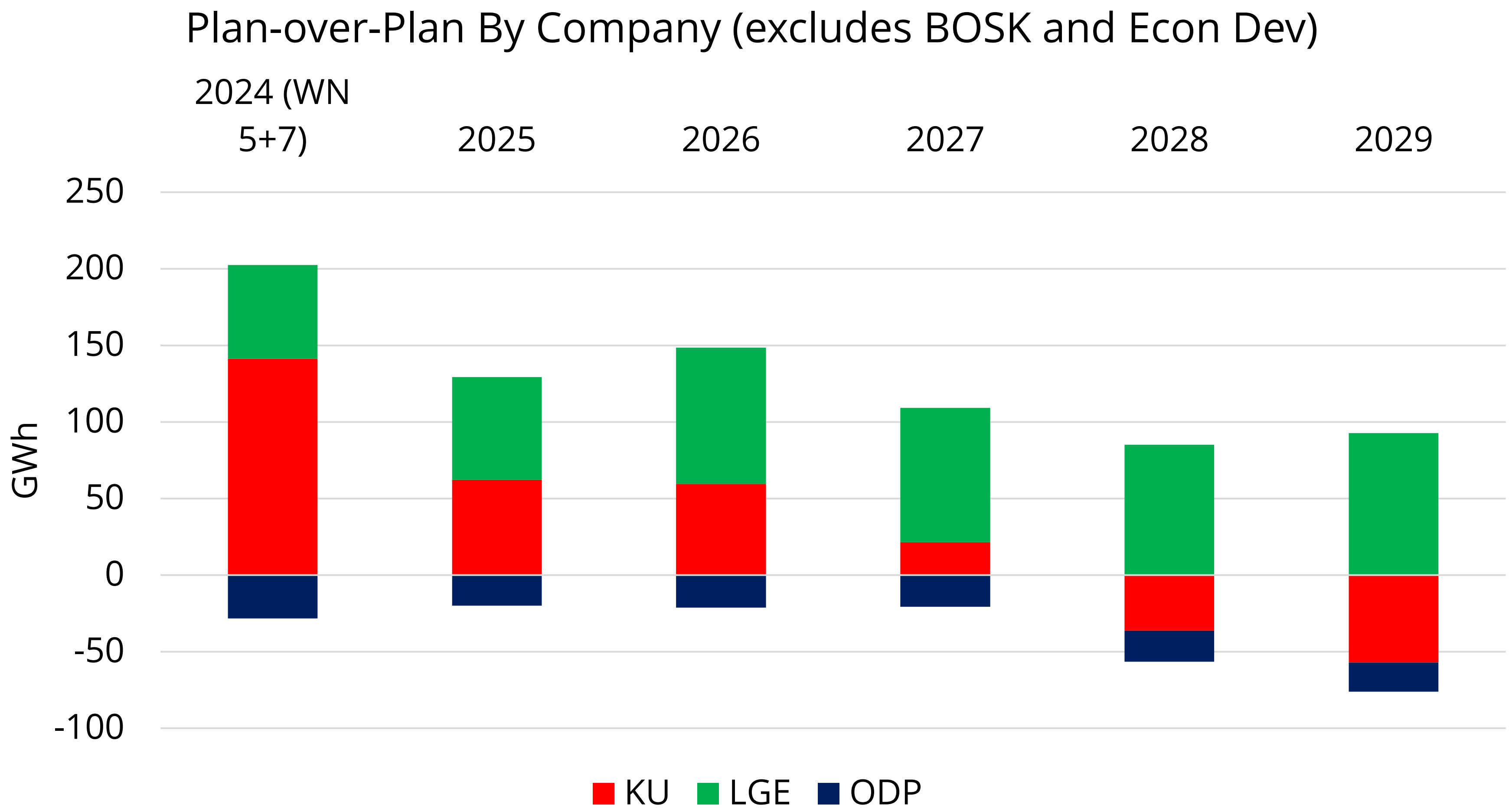
Balance of year lower PoP; slower BOSK Phase 1 ramp more than offsets positivity in other classes



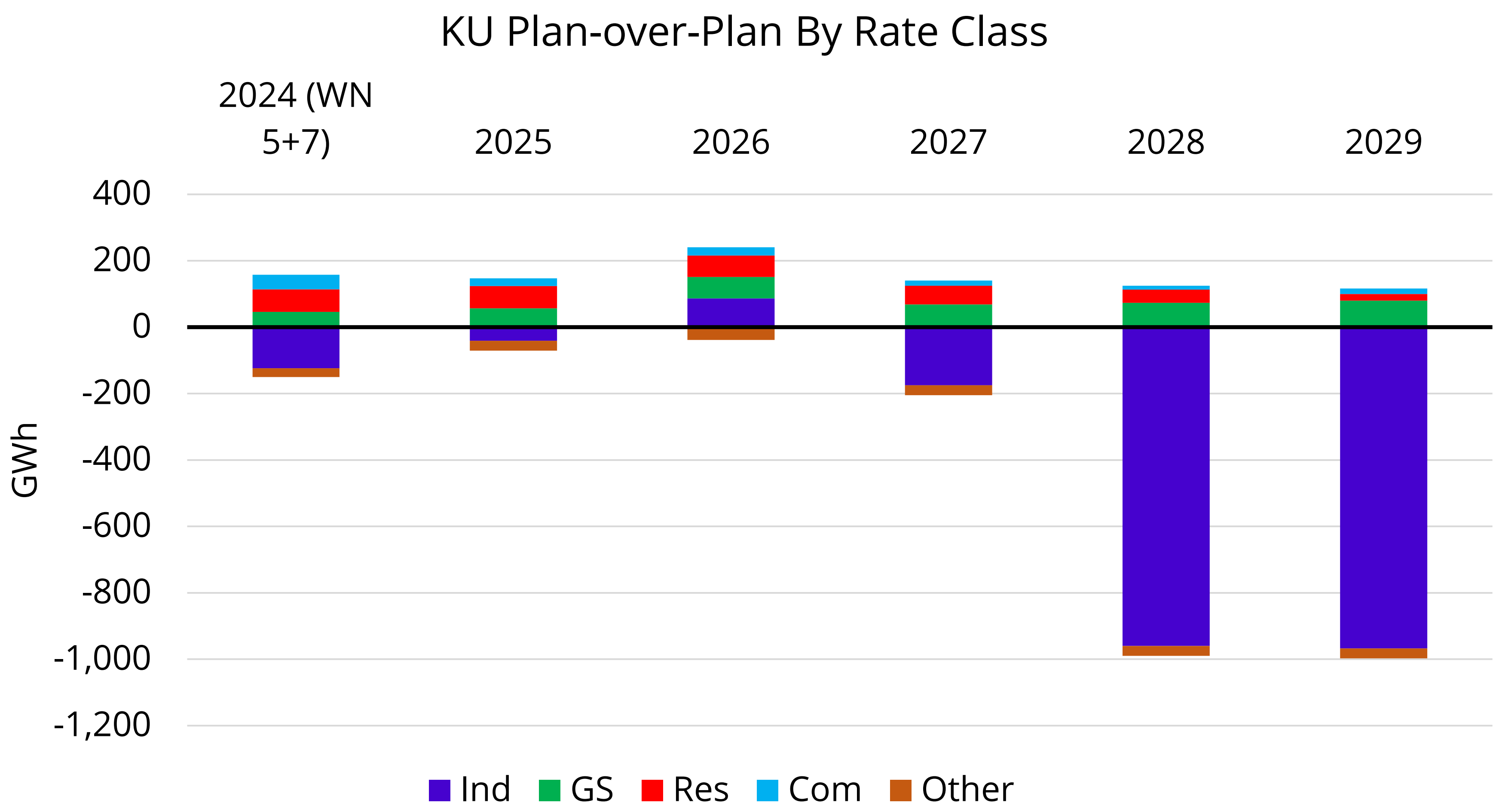
PoP differences for KU and LG&E are mostly positive near-term; LG&E Econ Dev more than offsets indefinite delay of BOSK Phase 2 long-term



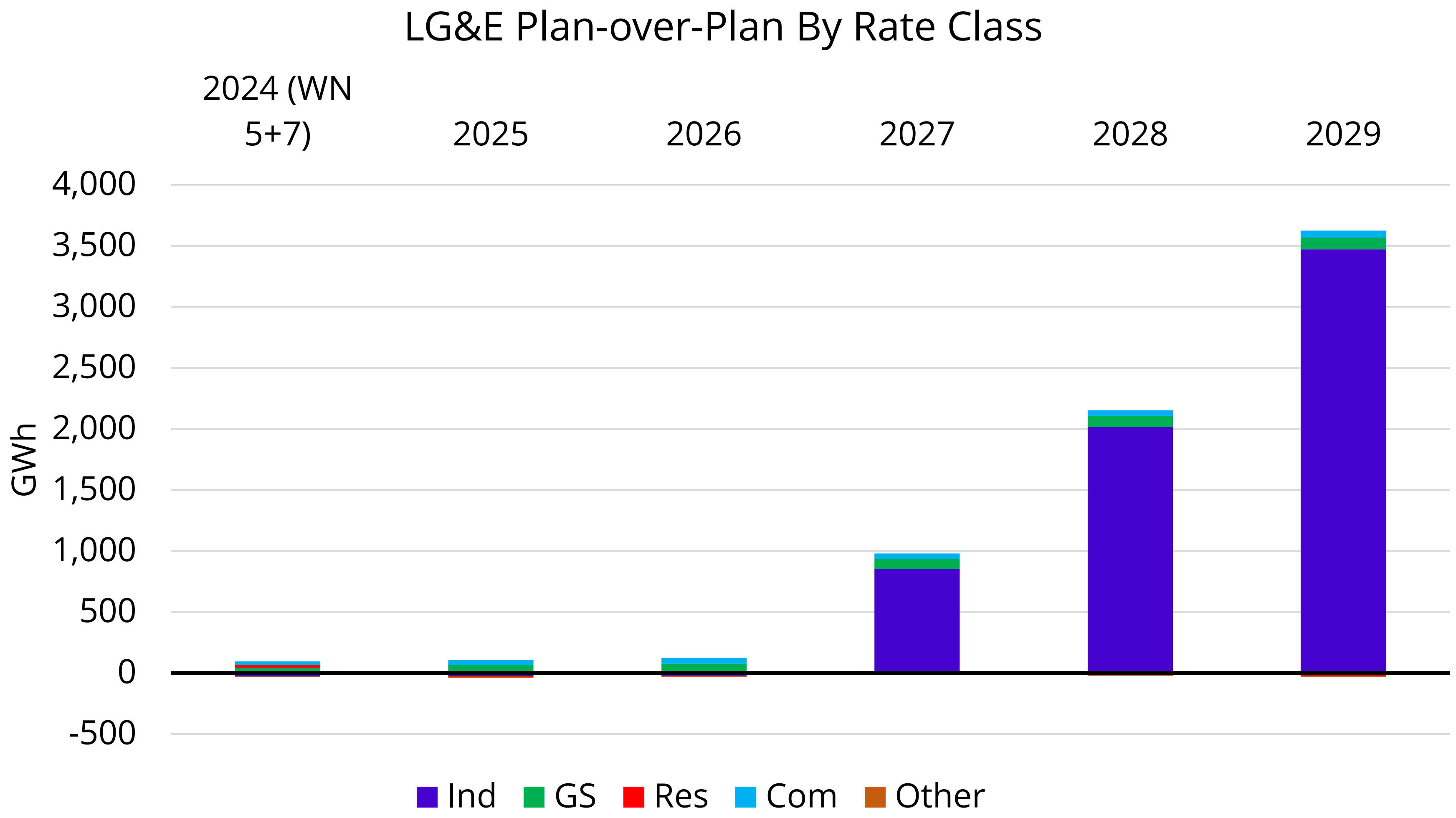
Removing BOSK and Econ Dev, Combined Company sales are slightly higher throughout BP



KU higher PoP through 2026 on strong RS and GS sales; lower thereafter due to BOSK Phase 2 delay

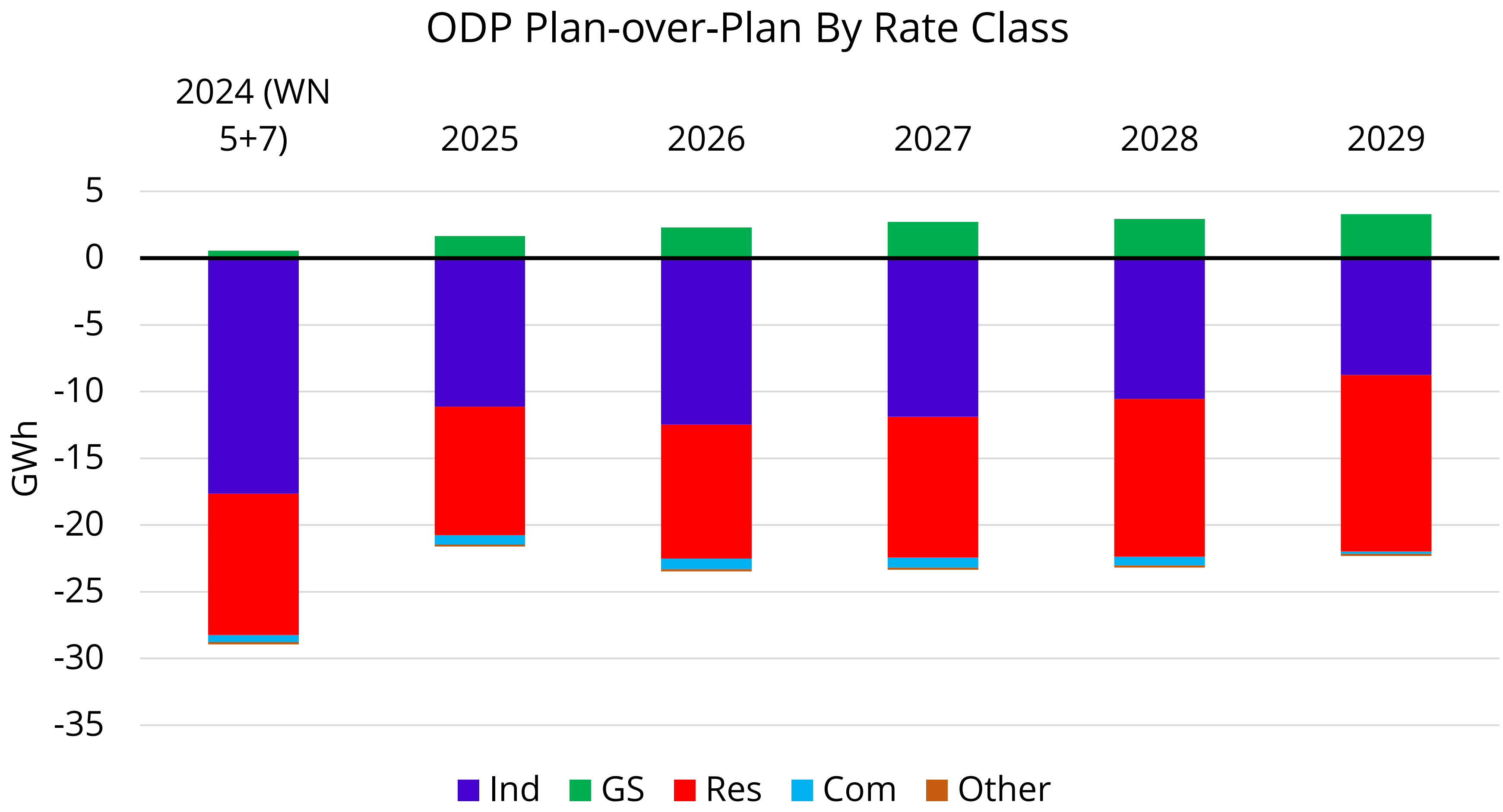


LG&E higher PoP throughout BP; Commercial and GS drive increases through 2026



Business Use

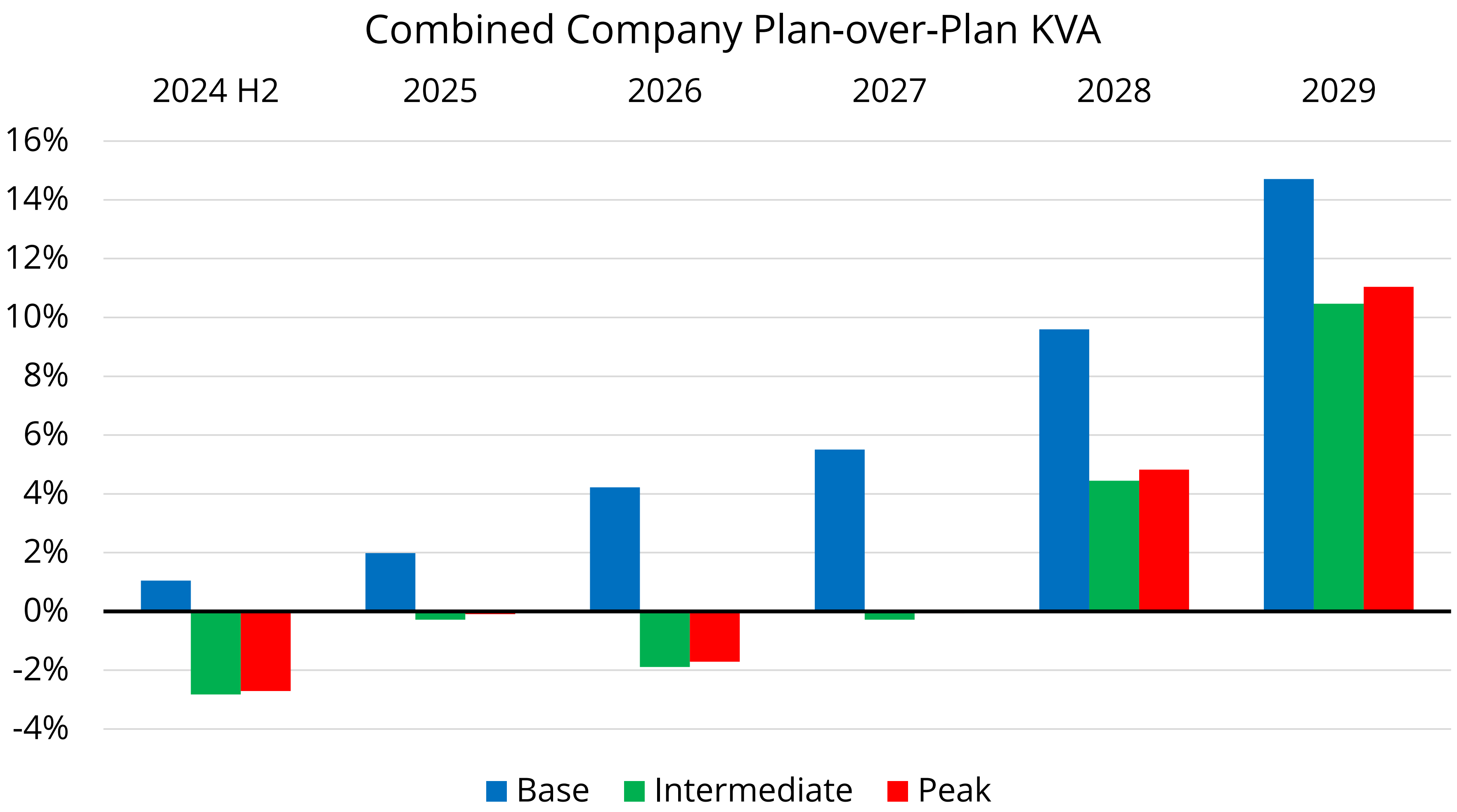
ODP lower PoP due to industrial losses and lower residential use-per-customer; GS positive PoP



Billed Demands

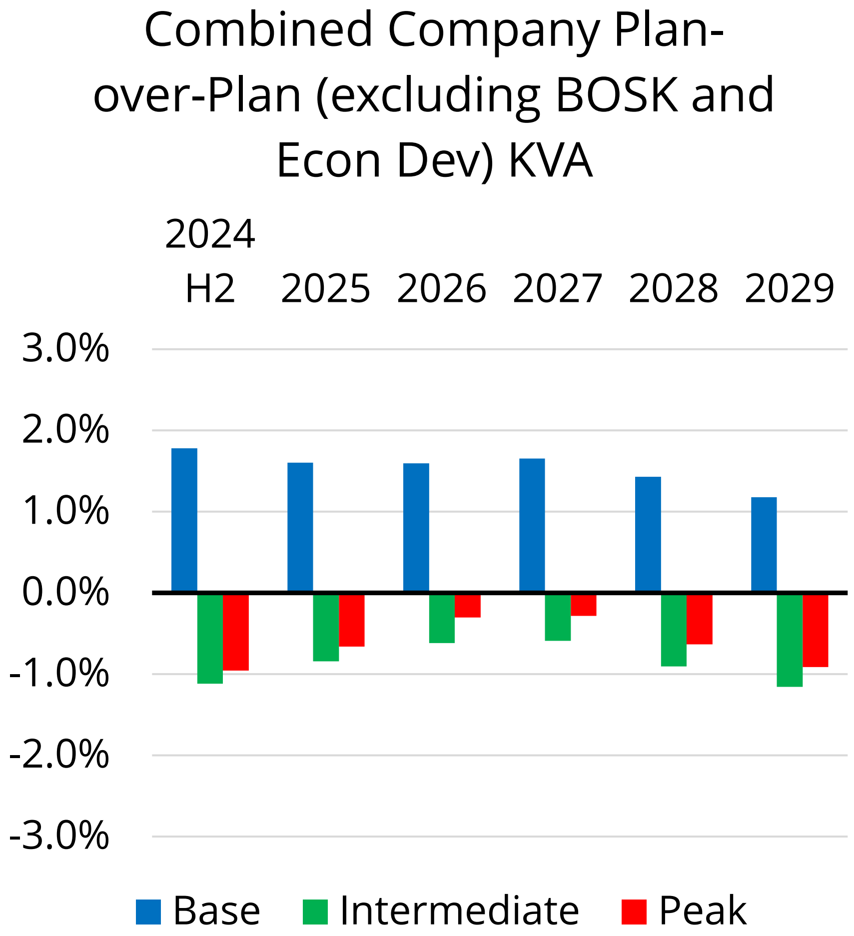
PPL companies

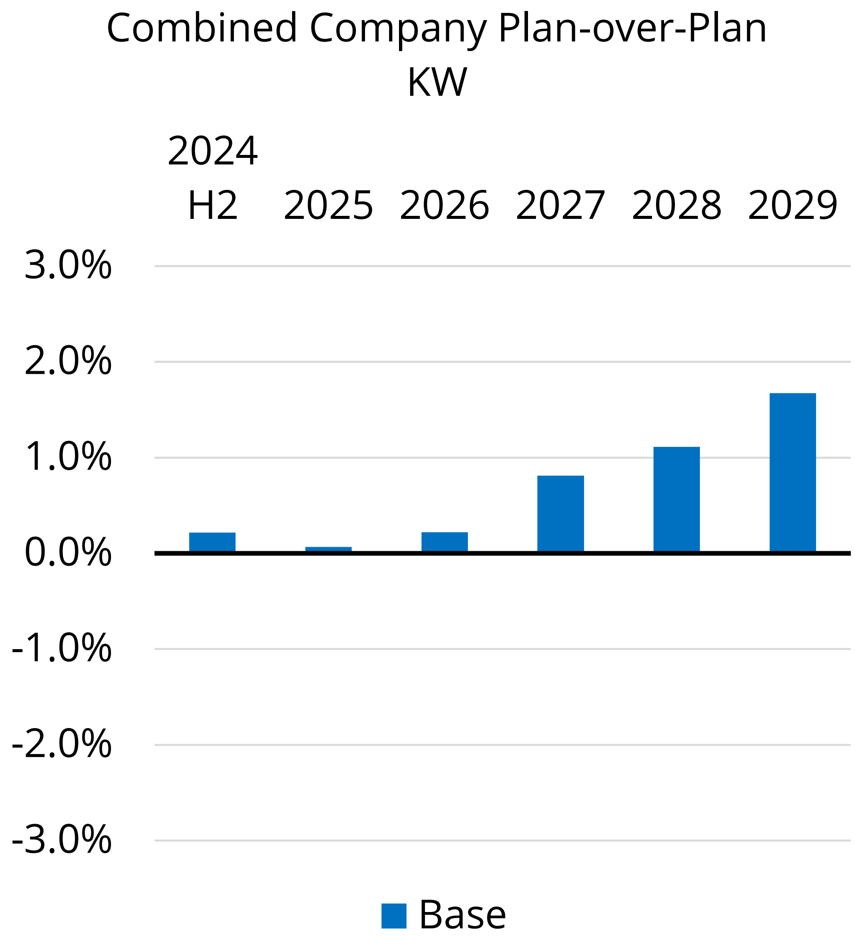
Econ Dev assumptions drive KVA PoP changes



Business Use

Removing Econ Dev and BOSK, billed demands in total virtually flat PoP





Business Use

Risks

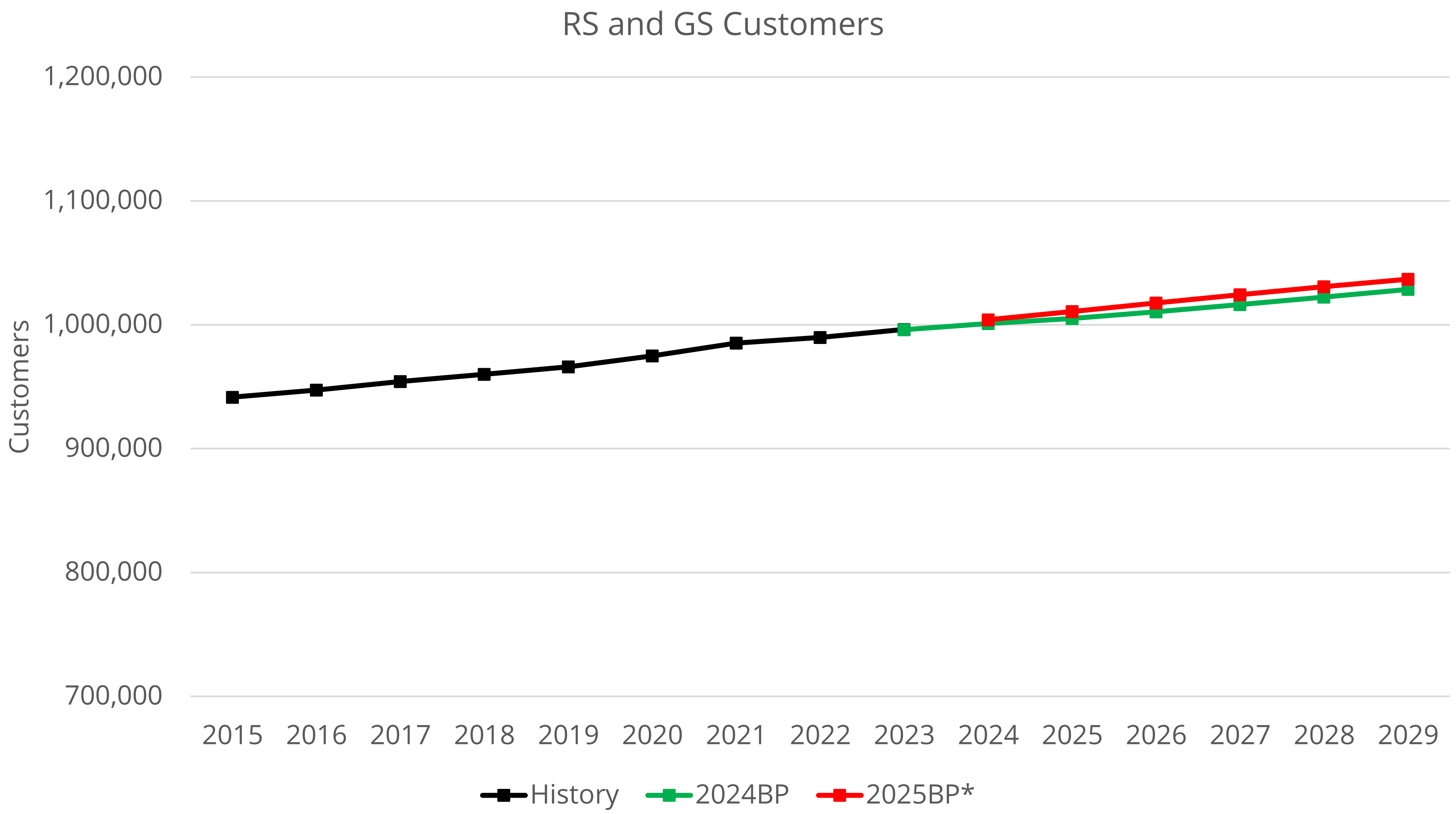
Risks to the 2025BP within the business planning period

- Weather
  - 1 standard deviation is around +/-500 GWh annually, or ~1.5%
- Upside Risk to Sales and Demands
  - Customer growth in all classes, but particularly industrial, related to Economic Development and state industrial development initiatives
  - Higher-than-forecasted electrification
- Downside Risk to Sales and Demands
  - Economic Development projects and Major Account expansions are delayed or canceled
  - Higher-than-anticipated customer investment / operating changes to reduce sales and billed demands
  - GS sales and PS demands lower than forecasted

Appendix

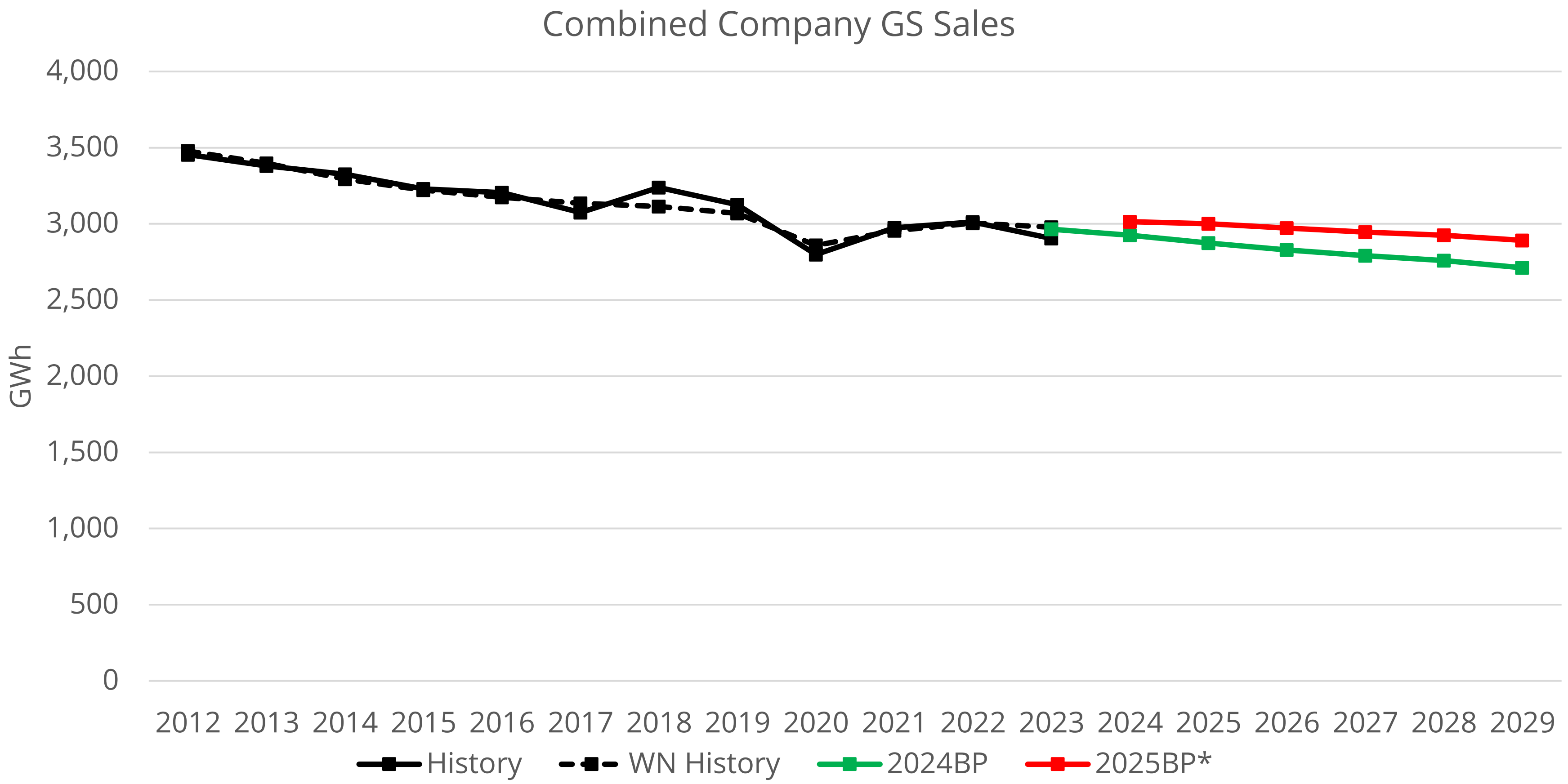
PPL companies

Residential and General Service customer forecasts slightly higher through 5-year BP period



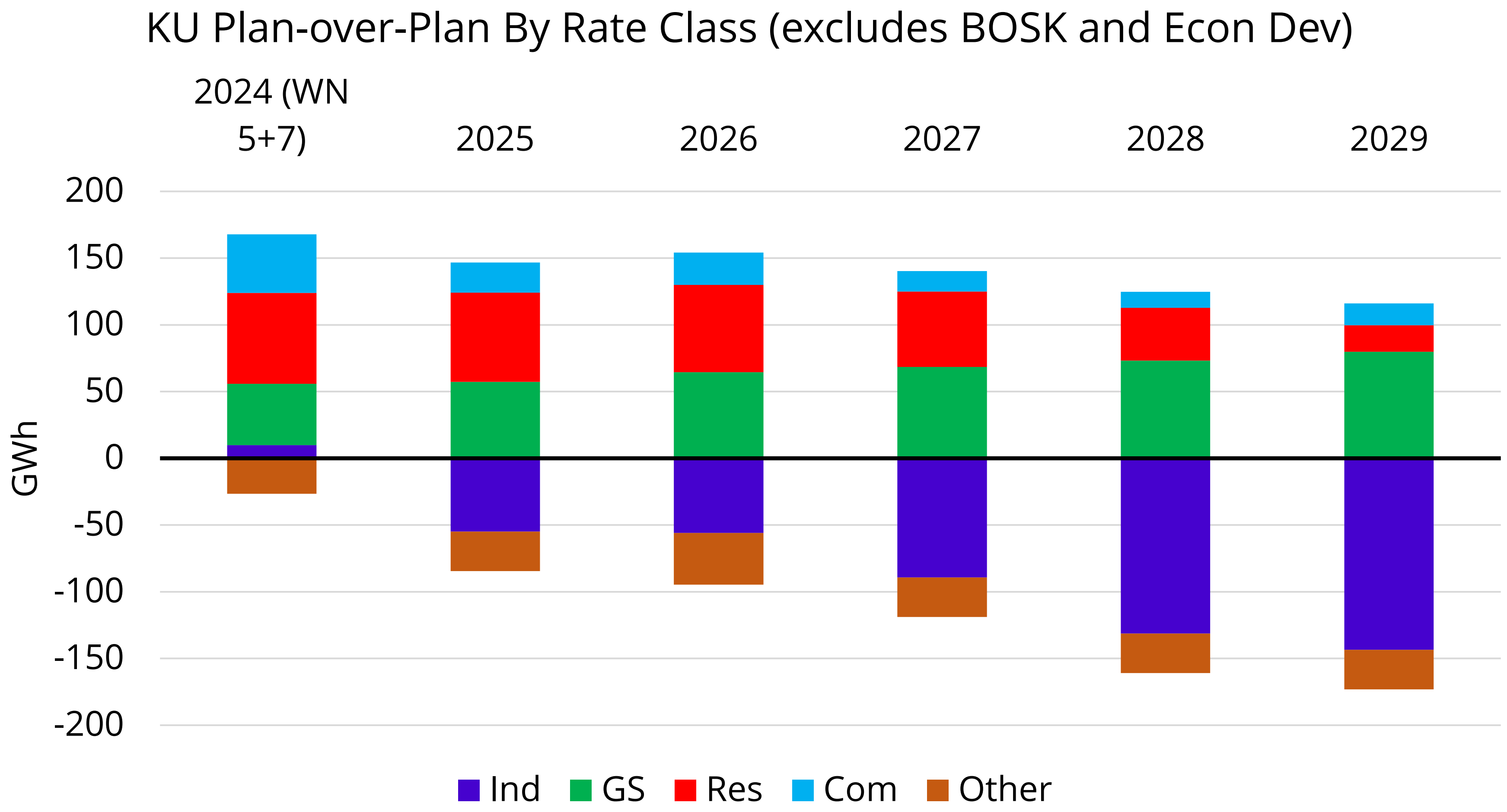
*2024 is 5 months of actuals and 7 months of forecast

2025BP GS sales begin from a higher point and decline at a slower rate than 2024BP, consistent with post-COVID trend and YTD WN variances

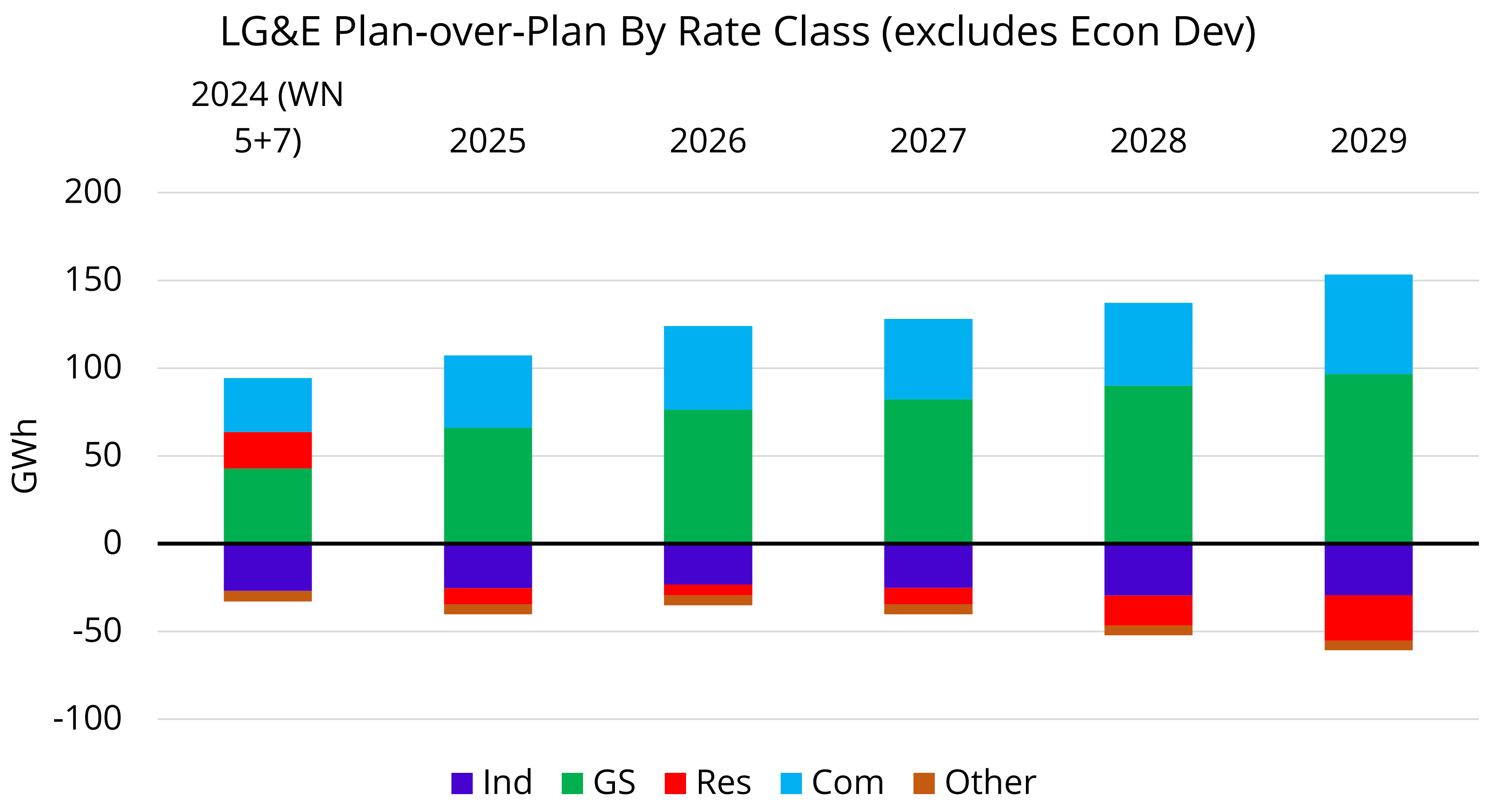


*2024 is 5 months of weather-normalized actuals and 7 months of forecast

Removing BOSK and Econ Dev, KU is higher PoP through 2027



Removing Econ Dev, LG&E higher plan-over-plan on Commercial and GS positivity



Sales excluding BOSK and Econ Dev decline at a slower rate in forecast than history

Rate Class	2019-2023 WN CAGR	2024BP 2024-2029 WN CAGR	2025BP 2024-2029 WN CAGR
Commercial	-1.7%	-0.8%	-0.8%
General Service	-0.7%	-1.5%	-0.8%
Industrial	-0.7%	3.5%	7.1%
Industrial excl. BOSk/Econ Dev	-0.7%	0.2%	-0.1%
Municipal	-2.5%	1.8%	1.7%*
Other	-2.0%	0.0%	0.1%
Residential	-0.1%	-0.2%	-0.4%

Company	2019-2023 WN CAGR	2024BP 2024-2029 WN CAGR	2025BP 2024-2029 WN CAGR
KU	-0.6%	1.7%	0.7%
KU excl. BOSK/Econ Dev	-0.6%	-0.2%	-0.4%
LG&E	-0.9%	-0.5%	4.4%
LG&E excl. BOSK/Econ Dev	-0.9%	-0.5%	-0.4%
ODP	-2.0%	-0.7%	-0.4%
Combined Companies (“CC”)	-0.7%	0.9%	2.1%
CC excl. BOSK/Econ Dev	-0.7%	-0.3%	-0.4%

*increase is primarily due to Barton expansion

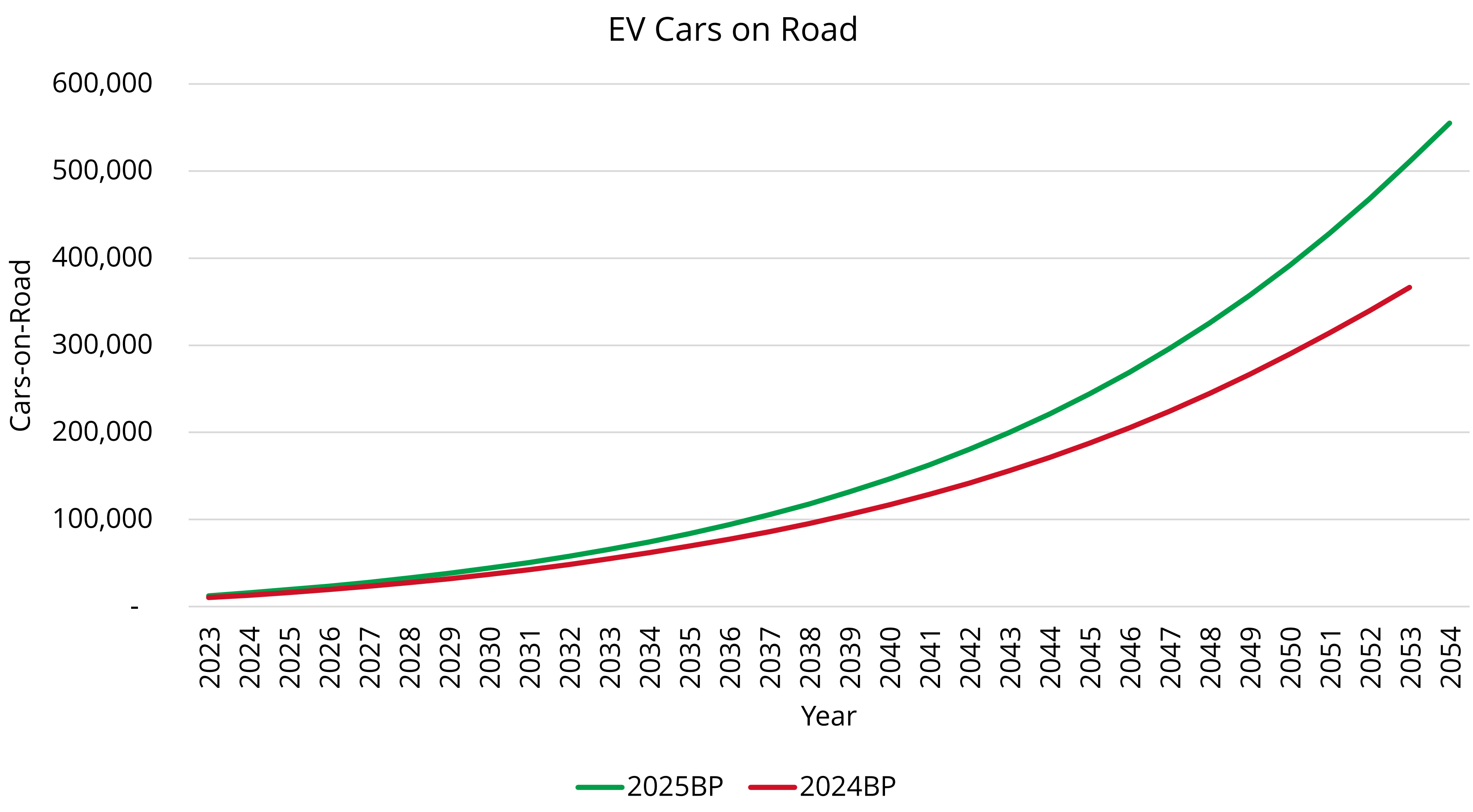
Major Account and Economic Development Forecast Process

- Communicate throughout the year with the Key Account and Economic Development teams to remain informed of changes with top 25 customers ("Major Accounts") and potential new customers
- Based upon that knowledge, create in-house sales and measured demand forecasts
- Send forecasts to Major Account customers to get their thoughts and suggested edits
- Finalize the forecasts based upon customer feedback

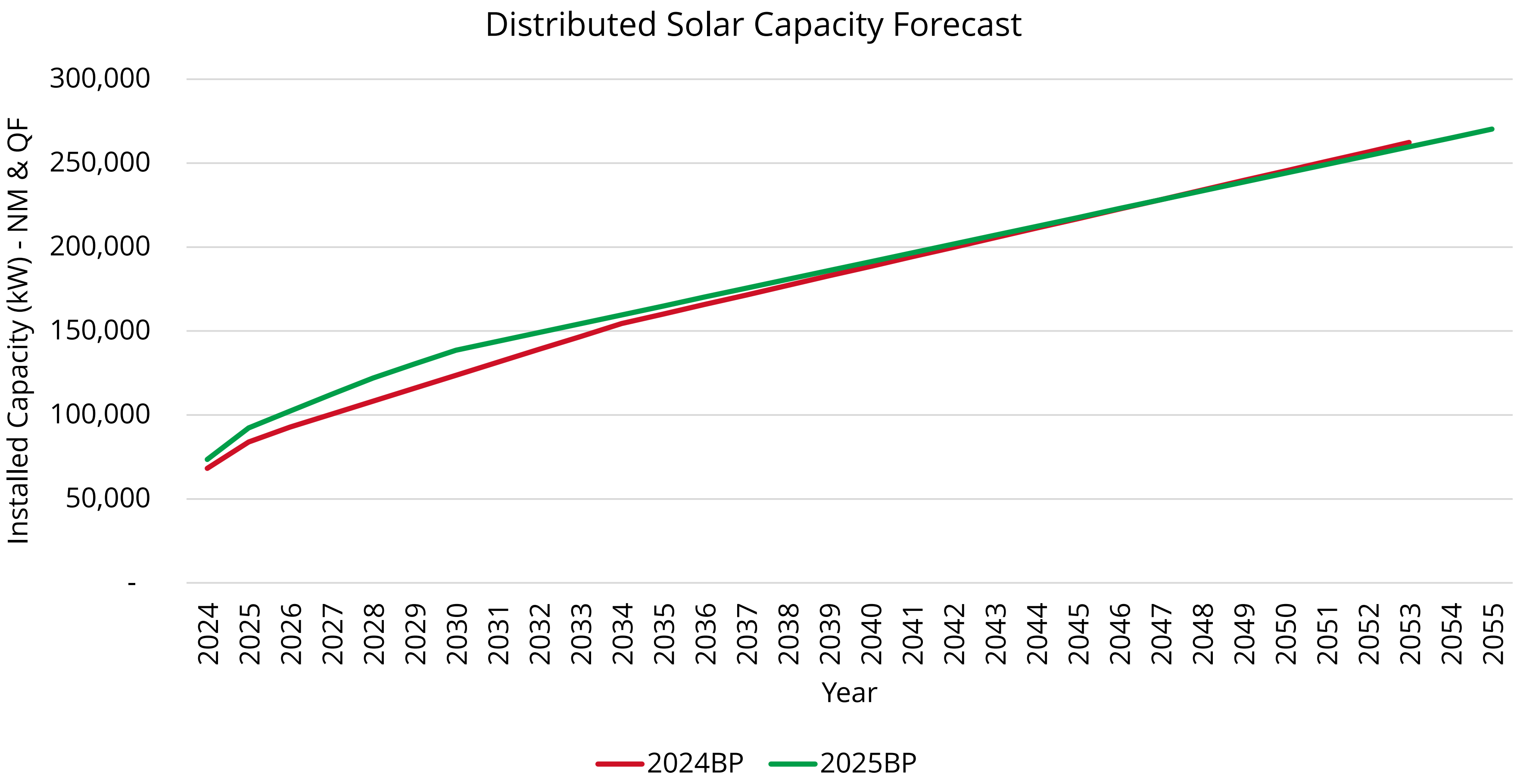
EV assumptions

- Around 10,000 miles driven per year
- 3.36 miles per kWh; 3 MWh per year per EV
- At-home charging impacts residential sales
- Consistent with 2024BP, added load associated with interstate charging based upon recent infrastructure bill
- Managed, Overnight Charging
  - No impact to monthly sales forecast, but does impact load shapes provided to Generation Planning

EV cars on road slightly higher in the near-term and higher long-term PoP



Higher 2025BP distributed solar capacity forecast reflects impact of EPA Solar-for-All program through 2030



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Electric Class Load Profile Forecast Process

PPL companies

Sales Analysis & Forecasting
March 2025

Table of Contents

1. Introduction

The Sales Analysis & Forecasting group develops the class load profile forecasts for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") as inputs to the Companies' cost of service studies. The purpose of this document is to summarize the process used to produce and validate these forecasts.

2. Input Data

Table 1 contains a summary of key inputs to this process. The processes used to forecast monthly sales and hourly energy requirements ("hourly loads") are summarized in a separate document ("Electric Sales & Demand Forecast Process").

Table 1: Inputs to Class Load Profile Forecast

Data Input	**Source**
5- and 15-Minute Customer Energy Usage	History: MV90 System, MDMS System
Calendar-Month Sales by Class	History: CCS / Revenue Accounting Forecast: Business Plan Load Forecast
Hourly Energy Requirements by Company	History: Energy Management System Forecast: Business Plan Hourly Load Forecast
Loss Percentages by Service Level	History: 2012 Line Loss Study

3. Methodology

LG&E and KU develop class load profile forecasts for the classes listed in Table 2. With limited exceptions, each class comprises one rate schedule. The goal of the forecast process is to develop profiles for each class that reflects the classes' hourly energy requirements under "normal" weather conditions.[1] Classes are considered weather-sensitive if weather was a significant explanatory variable in specifying the class's monthly sales forecast model.

[1] This means the sum of hourly energy requirements in a given month ties to the monthly normal forecast of billed sales converted to calendar sales and then grossed up for losses and company use. "Normal" weather is defined as the average weather over a 20-year historical period.

Table 2: LG&E and KU Classes

Class	Company	Rate Schedule / Service	Sample / Census	Weather-Sensitive
Residential	LG&E, KU	RS, VFD, RTOD	Sample	Yes
General Service	LG&E, KU	GS, GTOD	Sample	Yes
Power Service Primary	LG&E, KU	PS	Sample	Yes
Power Service Secondary	LG&E, KU	PS	Sample	Yes
Time-of-Day Primary	LG&E, KU	TODP	Census	No
Time-of-Day Secondary	LG&E, KU	TODS	Census	Yes
Retail Transmission Service	LG&E, KU	RTS	Census	No
Outdoor Sports Lighting	LG&E, KU	OSL	Sample	No
Louisville Water Company	LG&E	Special Contract	Census	No
Fluctuating Load Service	KU	FLS	Census	No
All Electric Schools	KU	AES	Sample	Yes
Unmetered Lighting	LG&E, KU	LS, RLS	Sample	No
Lighting Energy Service	LG&E, KU	LE	Sample	No
Traffic Energy Service	LG&E, KU	TE	Sample	No
EV Charge	LG&E, KU	EVC-L2	Sample	No
EV Fast Charge	LG&E, KU	EVC-FAST	Sample	No
EV Supply Equipment	LG&E, KU	EVSE	Sample	No
Muni Primary	KU	Special Contract	Census	Yes
Muni Transmission	KU	Special Contract	Census	Yes
Old Dominion Power	KU	N/A	Census	Yes

The Companies' most recent cost of service studies focused on the twelve months ending December 2026 ("Forecasted Test Period"). To forecast class load profiles for this period, the Companies first developed historical class load profiles for the twelve months ending December 2024 ("Historical Period"). After the historical load profiles were developed, they were used along with other inputs to forecast class load profiles for the Forecasted Test Period. This process is completed separately for LG&E and for KU. The following sections summarize the process in more detail.

3.1 Historical Period Class Load Profiles

Hourly class load profiles for the Historical Period are developed using customers' 5- and 15-minute energy usage data ("interval data"). The Companies have interval data for all customers in classes with time-of-day demand rates. Therefore, historical profiles for these "census" classes are an aggregation of interval data for the customers in each class by hour. For each of the remaining classes ("sample" classes), historical profiles are created based on interval data for a sample of customers. The samples were designed for this purpose and account for differences within each class in the way customers use electricity. In each hour of the Historical Period, the process ensures that the sum of class demands plus losses and company uses equals total hourly energy requirements for the company according to the Energy Management System ("EMS").

3.2 Forecasted Test Period Class Load Profiles

Class load profile forecasts are developed by allocating forecasted system energy requirements to classes based on the allocation of system energy requirements in the Historical Period. A key consideration in this process is accounting for differences in weather and non-weather factors between the Historical Period and the Forecasted Test Period.[2] For this reason, profiles for weather-sensitive and non-weather-sensitive classes are forecasted differently. For non-weather-sensitive classes, excluding FLS, hourly profiles for each month in the Historical Period are first scaled up or down so that the monthly sum of energy requirements in the scaled profiles equals monthly energy requirements in the Forecasted Test Period. This accounts for most differences in non-weather factors between the periods, but additional steps must be taken to create forecasted profiles that are aligned with the pattern of weekdays and weekends in the Forecasted Test Period. Because of its unique shape, the FLS class is not scaled up or down. Forecasted changes in monthly FLS energy is the result of load factor changes and not peak changes. Therefore, to ensure peaks are reasonable and align with history, the Companies selected historical days to achieve forecasted energy requirements.

Class profiles for a given weekday or weekend day in the Forecasted Test Period are developed based on a weekday or weekend day in the Historical Period with similar weather. The scaled non-weather-sensitive class profiles associated with this historical day are directly assigned to the forecast day. Then, for each hour of the historical and forecast days, the weather-sensitive portion of total system energy requirements is computed as the difference between total system energy requirements and the sum of energy requirements for non-weather-sensitive classes. The weather-sensitive portion of energy requirements in each hour of the forecast day is allocated to the weather-sensitive classes based on their share of weather-sensitive energy requirements in the corresponding hour of the historical day. Because the forecast and historical day have similar weather, this step accounts for most differences in non-weather factors between the Historical Period and Forecasted Test Period. A final step adjusts the forecasted profiles to account for differences between the periods in the class composition of weather-sensitive energy requirements and align monthly energy requirements for all classes with the separately-developed forecasts of monthly class sales.

The Companies' cost of service studies are focused on hours with high loads. Because the class profiles are forecasted based on historical days with similar weather, each class's contribution to load on peak days in the Forecasted Test Period is aligned – after adjusting for non-weather factors – with its contribution to load on peak days in the Historical Period. At the end of the

[2] Non-weather factors include the number of customers, end-use efficiencies, and industrial production levels.

process, the sum of class loads in each hour of the Forecasted Test Period equals the Companies' separately-developed forecast of system energy requirements.

4. Review

The forecast process has several built-in controls to ensure that the forecasted class load profiles are consistent with the separately-developed forecasts of hourly system energy requirements and monthly class-level sales. The Companies review the class load profile forecasts to ensure that they are reasonable in light of the Historical Period profiles and the forecasted changes in monthly class sales from the Historical Period and the Forecasted Test Period. Because the Companies' cost of service studies are focused on hours with high loads, the review is focused primarily on high load days to ensure they are reasonable.

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Generation
Forecast Process

PPL companies

Generation Planning & Analysis
2024

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1 Introduction

The Generation Planning group annually prepares a 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

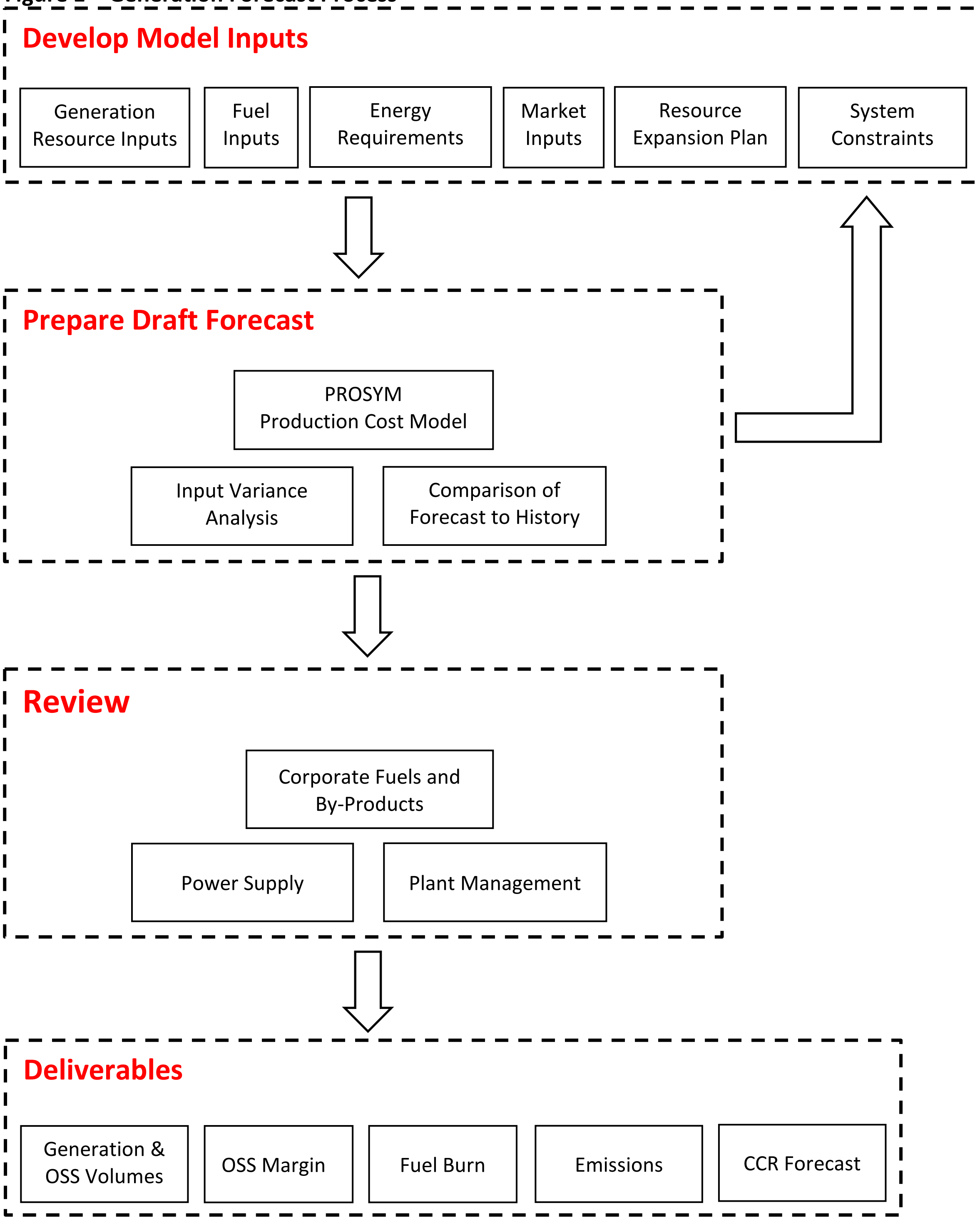
The Companies' generation forecast is developed using Hitachi ABB Power Grids' PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve 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, R, Microsoft Access, and Microsoft Excel are used to develop inputs and 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 Resource Inputs	Minimum and maximum capacity, heat rate, emissions rates, variable operating and maintenance costs, operating limits, unit availability, company allocation, renewable resources
Fuel Inputs	Coal, natural gas, and oil prices, fuel cost multipliers, CCR production rates and 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 resources
System Constraints	Transmission constraints, spinning reserve requirements, off-system sales constraints, dispatch order rules

3.1.1 Generation Resource Inputs

The generation resources modeled in PROSYM include the Companies' existing and (if applicable) planned generation resources. Generation resources 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.[1]

Generation resource inputs define the operating characteristics of the generation resources. These inputs include the resource's minimum and maximum capacity, heat rate, emissions rates, variable operating and maintenance costs, operating limits, unit availability, company allocation, and renewable resources. Each of these inputs is discussed further in the following sections.

3.1.1.1 Minimum and Maximum Capacity

The operating minimum, SCR minimum, and maximum capacity (or output) is specified for each generation resource as a megawatt ("MW") value for the summer, winter, fall, and spring seasons. SCR minimum applies only to units with SCRs and is the minimum capacity at which the SCR can operate (i.e., operation at a capacity level lower than the SCR minimum requires that the SCR be nonoperational). Capacity inputs are specified based on an analysis of historical data and unit rating tests but rarely change materially from forecast to forecast.

Brown units 5 and 8-11 are equipped with Inlet Cooling ("ICE") to increase output if needed during the summer months. The Companies model these ICE units as separate units with rules to ensure they do not operate simultaneously with their non-ICE counterparts.

[1] The Companies own 75% of Trimble County 1 and 2. Model inputs reflect 75% ownership.

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 resource 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 Emissions Rates

Where applicable, the Companies model the emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and carbon dioxide ("CO_2") for each generation resource:

- 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 depends on the vintage of the unit's flue-gas desulfurization ("FGD") equipment and is specified based on an analysis of historical data.[2] 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 an average SO_2 emission rate (specified in lb/MMBtu) 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 seasonally and with the unit's generation 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. Cane Run 7's NO_x emission rate is specified based on an analysis of historical data. For other gas units, NO_x emissions are modeled as an average NO_x emission rate (also specified in lb/MMBtu) estimated by the unit manufacturer.
- CO_2 Emissions: CO_2 emissions are modeled as an average CO_2 emission rate (specified in lb/MMBtu), which is dependent on the type of fuel burned in the unit and is based on engineering estimates.

3.1.1.4 Variable Operating and Maintenance Cost

Variable operating and maintenance ("O&M") costs include all incremental non-fuel costs that are incurred when operating the generation resource. For coal units, variable O&M includes the cost of operating environmental controls, including Flue Gas Desulfurization ("FGD"), Selective Catalytic Reduction ("SCR"), Sulfuric Acid Mist ("SAM")/SO3 Mitigation, Fabric Filter ("FF")/Baghouse, and Process Water Systems ("PWS"), as applicable. For Cane Run 7, variable O&M is specified as "Operating Charge" in dollars per operating hour and "Start Cost Adder" in dollars per start. These inputs reflect 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. For simple-cycle combustion turbines ("SCCTs"), the cost of major maintenance is specified as "Start Cost Adder" in dollars per start and considered in unit commitment and dispatch decisions but not included in the model's forecast of production costs.

3.1.1.5 Operating Limits

The following operating limits are modeled in PROSYM for each generation resource. Each of these inputs is specified based on operational experience.

- Minimum Up-Time: Minimum up-time is the minimum number of hours after coming online that a generation resource must remain online before it can be taken offline for economic reasons.

[2] Mill Creek Units 1-2 share the same FGD.

- Minimum Down-Time: Minimum down-time is the minimum number of hours after coming offline that a generation resource must remain offline before it can be brought back online.
- Mean Time to Repair: Mean time to repair is the average length (specified in hours) of forced outages.
- Ramp-Up Rate: Ramp-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output.
- Ramp-Down Rate: Ramp-down rate is the rate (specified in MW/hour) at which a generation resource can decrease its output.
- Run-Up Rate: Run-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output when it is first committed.
- Run-Up Hours: Run-up hours is the number of hours during which the run-up rate applies immediately after a generation resource is committed.

3.1.1.6 Unit Availability

The following unit availability inputs are modeled for each resource. These inputs determine the extent a resource is available for operation.

- 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 resource is unavailable due to a forced outage, derate, 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 resources modeled are either wholly or jointly allocated to LG&E and/or KU. For each generation resource, the Companies' allocation is specified to facilitate the process of creating generation and other forecasts by company.

3.1.1.8 Renewables

The Companies model renewable resources depending on the characteristics of each resource. KU's hydro facility, Dix Dam, is modeled using a monthly energy forecast which is based on history. LG&E's hydro facility, Ohio Falls, is modeled using monthly maximum capacity, also based on history. For solar facilities and power purchase agreements, the Companies model an hourly generation forecast which is correlated to the weather forecast on which the hourly energy requirements forecast is based.

3.1.2 Fuel Inputs

Each thermal generation resource is associated with one or more fuel forecast for startup and for online operation. The fuel inputs specify the cost of fuel, the fuel's heat and SO_2 content, the quantity of fuel required for startup, and – for generation resources 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 coal combustion residuals ("CCR") production rates and prices based on forecasted CCR revenues and costs.[3] The model makes commitment and dispatch decisions based on replacement fuel costs, while an estimate of total fuel cost is based on inventory fuel costs including fixed costs.

[3] CCR are by-products such as fly ash and bottom ash left over after coal is burned and gypsum, which is created as sulfur dioxide is removed from flue gas.

3.1.2.1 Coal Prices

A forecast of delivered coal prices is developed for each station in conjunction with the Coal Supply and By-Products Marketing department. These forecasts reflect the cost curve for 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 volume weighted average of the price of coal already under contract and the market price of coal. In the initial years of the forecast, the market price is a blend of coal bids received, but not under contract, and a forecast that reflects the historical relationship between coal and natural gas prices. This relationship is also used to develop a long-term coal price forecast based on the long-term natural gas 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 interpolated to a price forecast published in the EIA's most recent Annual Energy Outlook. The Henry Hub forward market prices are then shaped monthly and adjusted to local delivered prices to KU and LG&E units using an average annual loss factor and a variable charge per MMBtu, which 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 oil price forecast first uses NYMEX New York Harbor #2 fuel oil monthly contract settled prices as long as there is 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 a third party's latest long-term 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 historical 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 Fuel Cost Multiplier

Fuel cost multipliers ("FCM") are defined for large-frame combustion turbines to align the generation forecast to history and prevent an unreasonable forecast of generation from energy-limited resources. The model uses FCM as a factor applied to fuel cost in order to determine the fuel cost used for commitment and dispatch decisions, but it is not included in the model's forecast of total fuel costs. The Companies develop the FCMs by setting an artificial price floor at a cost that allows the capacity factors of the large-frame combustion turbines to more closely reflect historical usage and remain below any environmental or operational restrictions. The Companies also use FCMs to distribute generation across the combustion turbines from more efficient units like those at Trimble County to less efficient units like those at Brown to reflect real-world considerations such as the availability of firm delivery capacity.

3.1.2.5 CCR Production Rates and Prices

A forecast of revenues and costs resulting from the Companies' sales and management of CCR is developed for each station based on inputs from plant management and the Corporate Fuels and By-products department. CCR prices and handling costs are combined to calculate a net value of CCR by CCR type and station (in $/ton), to account for the value and cost of CCR production and management. A forecast of CCR production rates (in lb/MMBtu) is developed based on historical data and forecasted fuel characteristics.

3.1.2.6 Other Fuel-Related Inputs

Other fuel inputs include the fuel blend ratio, the quantity of startup fuel, and the fuel's heat and SO_2 content.

- Fuel Type: For each generation unit, the type of fuel burned during operation is specified.
- Fuel Blend Ratio: Trimble County 2 burns a blend of Illinois Basin and Powder River Basin coals. Because the prices of these coals are specified in separate forecasts, the fuel blend ratio determines the weighting that is used to compute the price of coal for Trimble County 2.
- Type and Quantity of Startup Fuel: For each generating unit, the startup fuel type and quantity are the type and amount of fuel required to start the unit. These inputs are specified by fuel type and in MMBtu 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.

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 volume limits, and OSS and economy purchase price threshold values. 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 ("PJM-S") interface/pricing point, which is used in the planning process to represent the electricity market.[4] In the initial years, monthly forward market prices for PJM West Hub ("PJM-WH")[5] as of a specific recent quote date are used as a basis for developing an hourly forecast of PJM-S prices, reflecting the most current view of forward prices at the time the forecast was prepared.[6] In the

[4] 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.
[5] 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.
[6] The quoted "off-peak wrap" forward prices for PJM-WH are split into off-peak (7x8) and weekend (2x16) peak types using historical ratios.

subsequent years, annual peak market prices are derived by applying a market implied heat rate to the Companies' natural gas price forecast. Annual off-peak and weekend prices are derived by applying market implied ratios relative to peak pricing to the aforementioned peak market price forecast. Monthly prices are derived by applying monthly weighting factors by peak type to the annual price forecasts. The monthly weighting factors are based on the forward average of the monthly weighting by peak type.

Monthly 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, based on their historical correlation. 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 monthly 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 ratios of hourly prices to daily prices by month and by peak type and then applying an historical PJM WH/PJM-S discount factor.

3.1.4.2 Emission Allowance Prices

The dispatch cost for each unit includes the unit's fuel cost, variable O&M costs, the cost or revenue from CCR management, and the cost of emission allowances.[7] Emission allowance price forecasts are developed for SO_2, ozone seasonal NO_x, and annual NO_x emission 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 a third-party's most recent long-term planning scenario. No CO_2 emission allowance prices are included.

3.1.4.3 Hourly Off-System Sales and Purchase Volume 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. Because the volatility of available transmission capacity cannot be modeled effectively 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.

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 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 resources planned, if any, to be added to the Companies' generation portfolio to meet customers' needs for energy and capacity. These generation resources can take the form of new generating units or power purchase agreements with a third-party provider. Generation resource inputs are discussed in Section 3.1.1.

[7] Ozone seasonal NO_x emission allowance prices are dispatched at $0 through 2024 to maximize allocations in the Good Neighbor Plan.

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 resources to load under a variety of circumstances. Despite the flexibility that is afforded the Companies, some constraints can occur in real time. For example, the Companies model a limit to the energy that can flow from LG&E to KU.

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 are party to 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. The Companies model these reserve requirements.

3.1.6.3 Off-System Sales 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 resources are dispatched. The majority of generation resources are dispatched economically, as specified with the "Commit" variable as "=economic" or "3." However, some units are specified with "Commit" as "4" or "5," meaning these units aren't available for commitment until all the economically dispatched units are online. For example, curtailment of the Companies' CSR customers is limited to times when most or all other company-owned resources have been or are being dispatched. The dispatch order rules enable the Companies to model this constraint.

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 for each step reveals the impact of changing each input (or group of related inputs) incrementally, and 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 resource
- Annual/monthly fuel burn by generation resource
- Annual startup fuel by generation resource
- Annual SCCT starts and 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 resource
- 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
- CCR Production Forecast

2025 Business Plan: Generation & OSS Forecast

Generation Planning & Analysis
December 13, 2024

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2025 Plan key topics

- Lower commodity prices drive lower fuel expense and production costs per MWh despite increasing native load
- Resources through 2029 reflect 2022 CPCN order, 2024 IRP, and recent updates
  - — Mill Creek 1 retirement at end of 2024
  - — Mill Creek 2 retirement/Mill Creek 5 online in June 2027
  - — 6 solar PPAs terminated by developers, canceled due to price reopeners, or delayed indefinitely
  - — 2 owned solar projects continue to move forward (2026, 2027)
  - — Brown BESS online in 2027
  - — Ghent 2 SCR in 2028
  - — 400 MW BESS in 2028
  - — Seasonal NO_x prices reflect more stringent rules beginning in 2028
  - — ELG and 111(b) and 111(d) rules considered unlikely to move forward given legal challenges
- CCR revenues projected to be $60-70 million per year

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Lower fuel prices result in lower system costs vs. 2024 Plan

Plan-over-Plan Change (%)	2025	2026	2027	2028	2029
Native Load	0.2%	1%	2%	3%	8%
Coal Prices (ILB Minemouth)	-14%	-10%	-6%	-5%	-2%
Coal Prices (LKE Wgt Avg)[1]	-3%	-5%	-5%	-5%	-2%
Gas Prices (LKE Wgt Avg)[1]	-8%	-3%	-4%	-4%	-2%
Electricity Prices (PJM-SI ATC)	-1%	2%	1%	2%	3%

1) Fuel prices reflect inventory costs

Native Load Production Costs	2025	2026	2027	2028	2029
2024 BP ($M)	923	975	991	1,042	1,048
2025 BP ($M)	891	932	968	1,033	1,104
Plan-over-Plan Change ($M)	-33	-43	-23	-8	56
Plan-over-Plan Change (%)	-4%	-4%	-2%	-1%	5%

- Increased native load
- 2025 fuel prices 3-8% lower
- Native load production costs 4% lower to 5% higher in total
  - Excludes REC sales and owned-solar production tax credit

Native load production costs are lower; OSS contribution is mostly higher

Native Load Production Costs[1] ($/MWh)	2025	2026	2027	2028	2029	CAGR
2024 BP	28.20	29.87	30.18	30.98	31.36	2.7%
2025 BP	27.14	28.37	28.76	29.69	30.62	3.1%

OSS Contribution (100%, $M)	2025	2026	2027	2028	2029
2024 BP	5.1	5.9	9.3	10.6	11.2
2025 BP	7.0	9.0	9.9	10.1	12.7

1) Includes fuel costs, consumables, purchases, and variable PPA costs

- Lower fuel prices drive lower native load production costs despite increasing load
- Lower ozone NO_x (ONO_x) prices through 2027, lower coal prices, plus slightly higher electricity prices in 2026+ drive mostly higher OSS contribution

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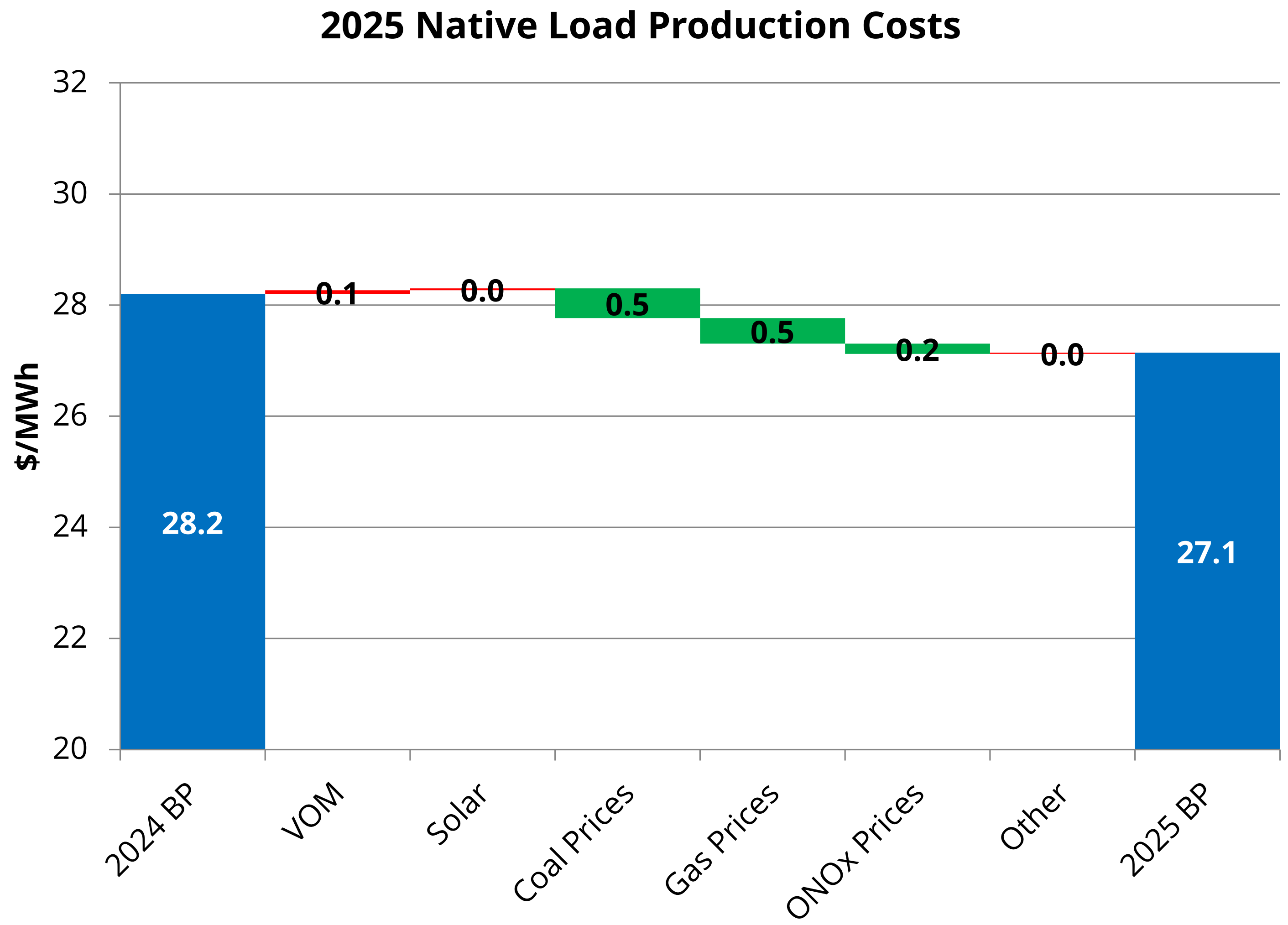
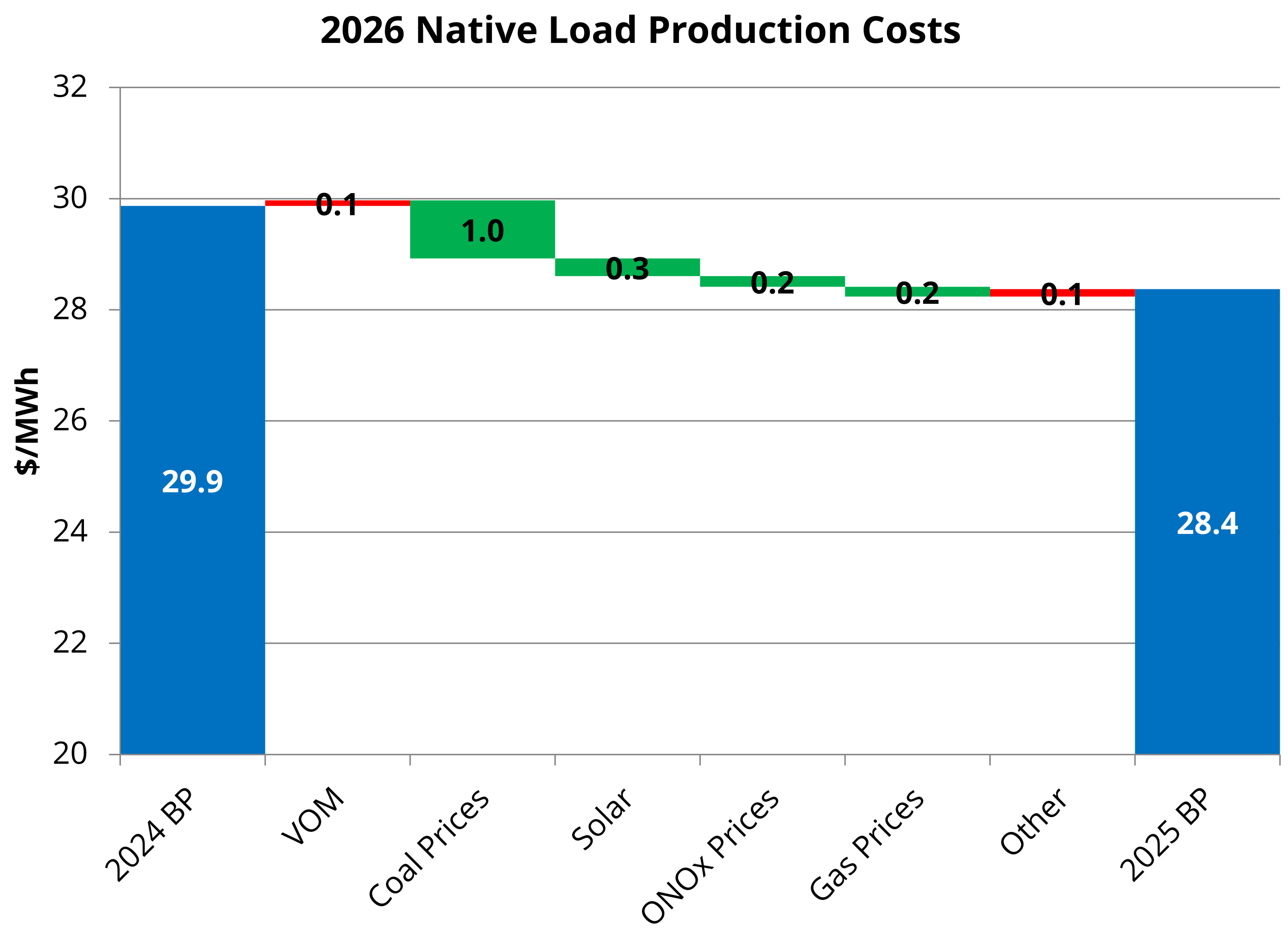
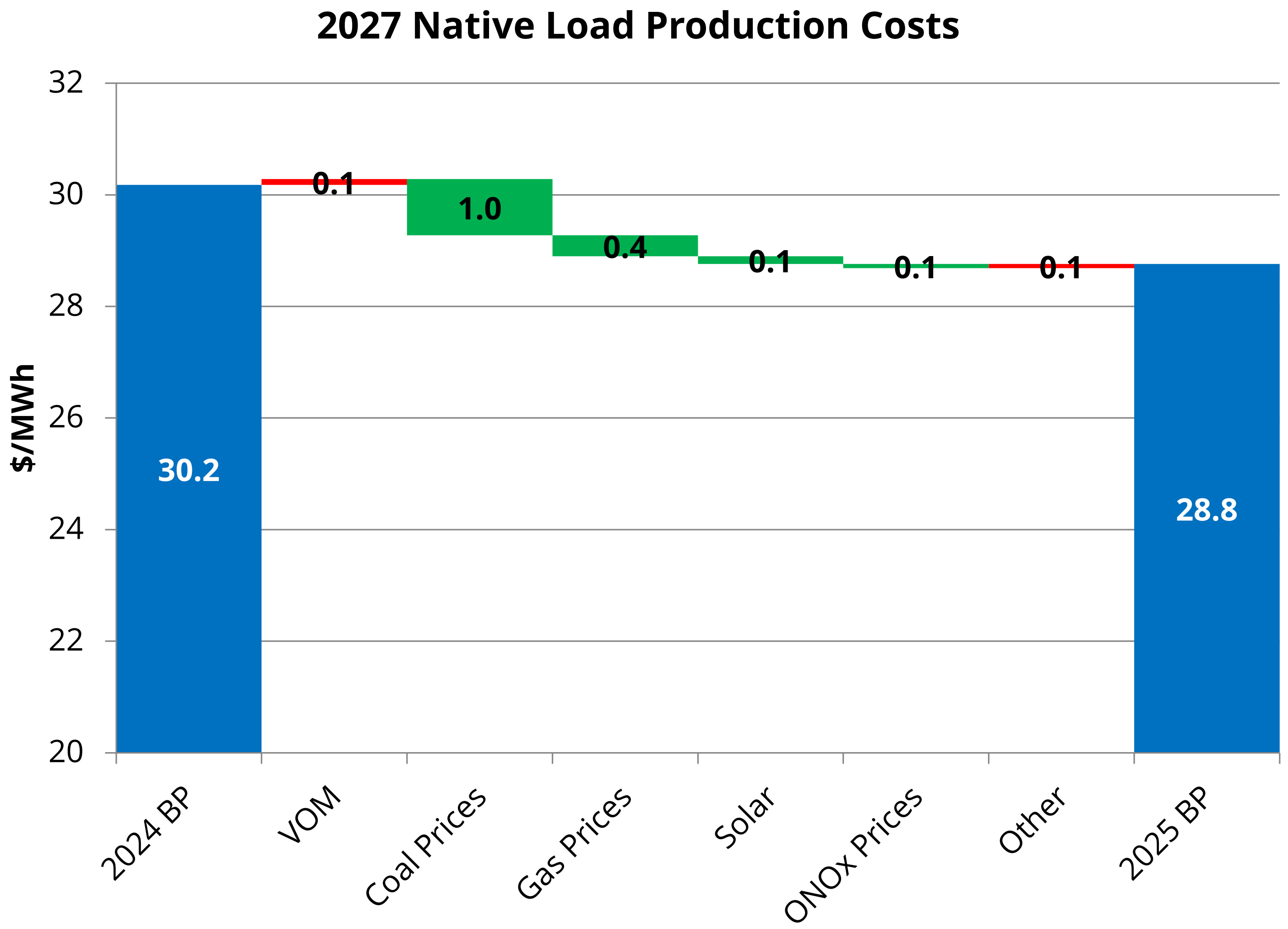
In 2025, lower fuel and ONO_x prices drive lower variable production costs



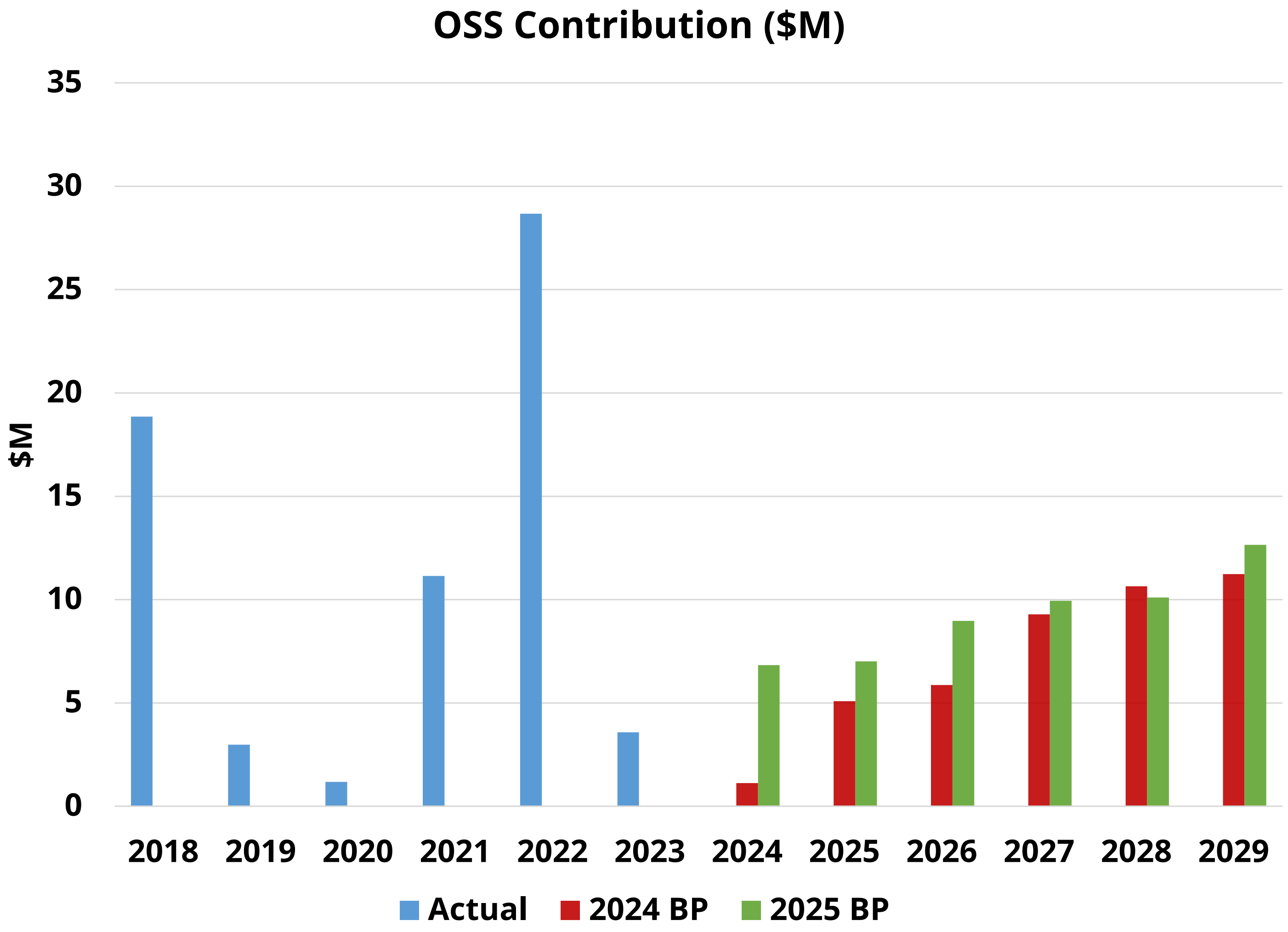
In 2026, lower fuel and ONO_x prices drive lower variable production costs



In 2027, lower fuel and ONO_x prices drive lower variable production costs



OSS contribution higher due to higher electricity prices, lower ONOx prices, and lower coal prices

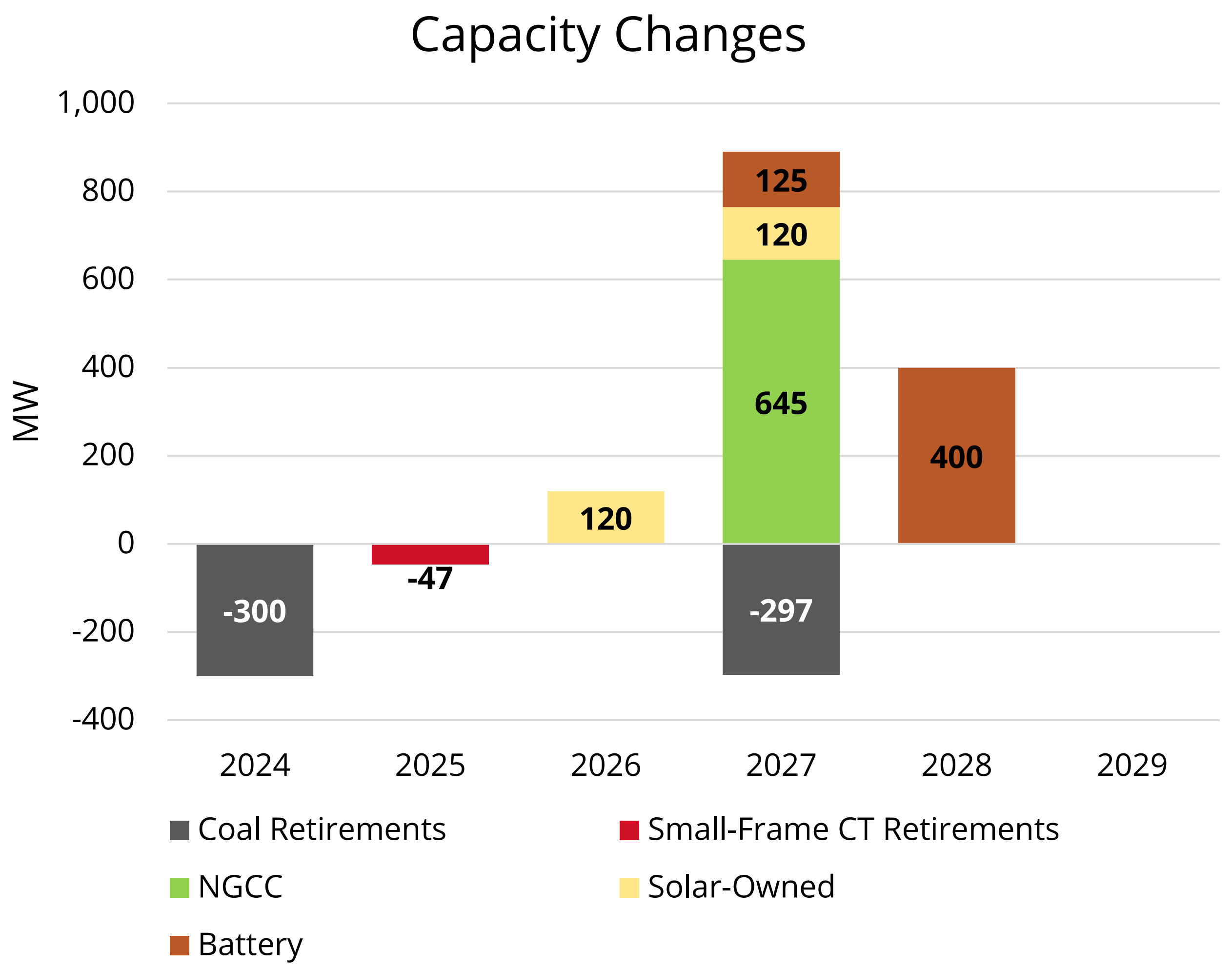


2025 BP in 2024: 6+6

- 2025 OSS contribution of $7.0 million
  - $1.9 million higher vs. 2024 Plan

Resource plans

- Business Plan focuses on 5-year period from 2025 to 2029
- Resource plans consistent with 2022 CPCN order, 2024 IRP, and recent updates
- Solar PPAs removed from near-term capacity plan



Environmental update

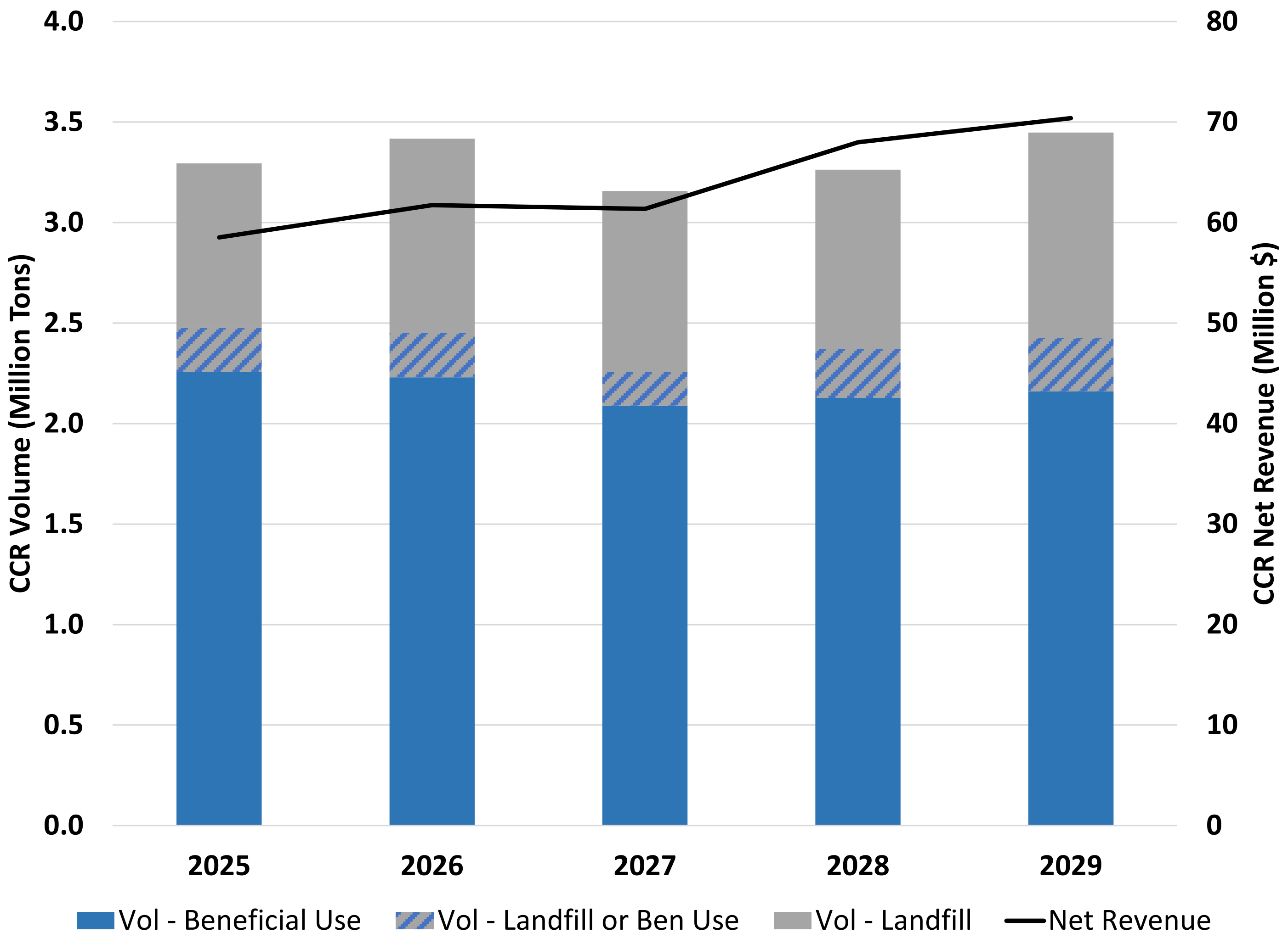
- Monitoring Good Neighbor Plan status and implications
  — Group 2 ONO_x emission allowance prices assumed through 2027, more stringent Group 3 pricing assumed beginning in 2028

- Jefferson County NAAQS
  — NO_x emission agreement at Mill Creek for May-October ends in 2024 with Mill Creek 1 retirement

- ELG and 111(b) and 111(d) rules considered unlikely to move forward given legal challenges
  — No CO_2 prices assumed in 2025 BP
    - 111(b) and (d) compliance modeled in 2024 IRP scenario
  — No assumed impact from new ELG rules through Business Planning period

- Dispatch reflects CCR implications
  — Landfill handling costs
  — Beneficial use revenue opportunities net of handling costs

$60-70 million in projected annual CCR revenue



Modeled EFOR based on historical performance; EFOR assumptions reflect gradual increases for MC2 after 2025

Unit	Modeled EFOR %		
	2025 BP	2024 BP	2025 BP - 2024 BP
Brown 3	5.8	6.1	(0.3)
Ghent 1	3.1	3.2	(0.1)
Ghent 2	3.1	4.0	(0.9)
Ghent 3	3.1	3.2	(0.1)
Ghent 4	3.1	3.2	(0.1)
Mill Creek 2	4.8	4.8	0.0
Mill Creek 3	3.1	3.2	(0.1)
Mill Creek 4	3.1	3.2	(0.1)
Trimble County 1	3.1	3.2	(0.1)
Trimble County 2	2.7	4.1	(1.4)
Cane Run 7	1.6	2.2	(0.6)
2025 Weighted Average EFOR	**3.2**	**3.6**	**(0.4)**

Unit	2025	2026	2027	2028	2029
Mill Creek 2	4.75	5.50	6.25		
Mill Creek 5			1.60	1.60	1.60

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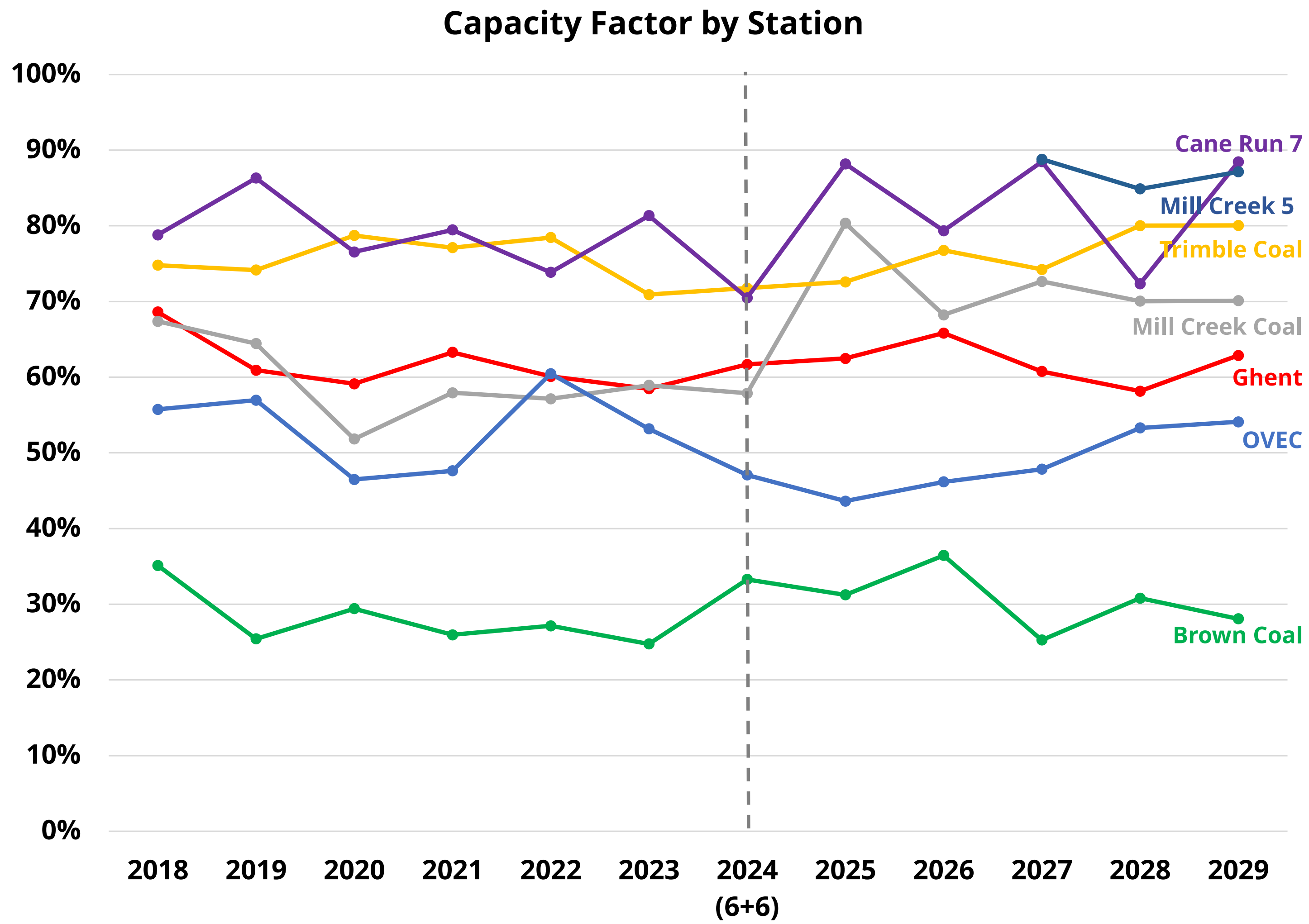
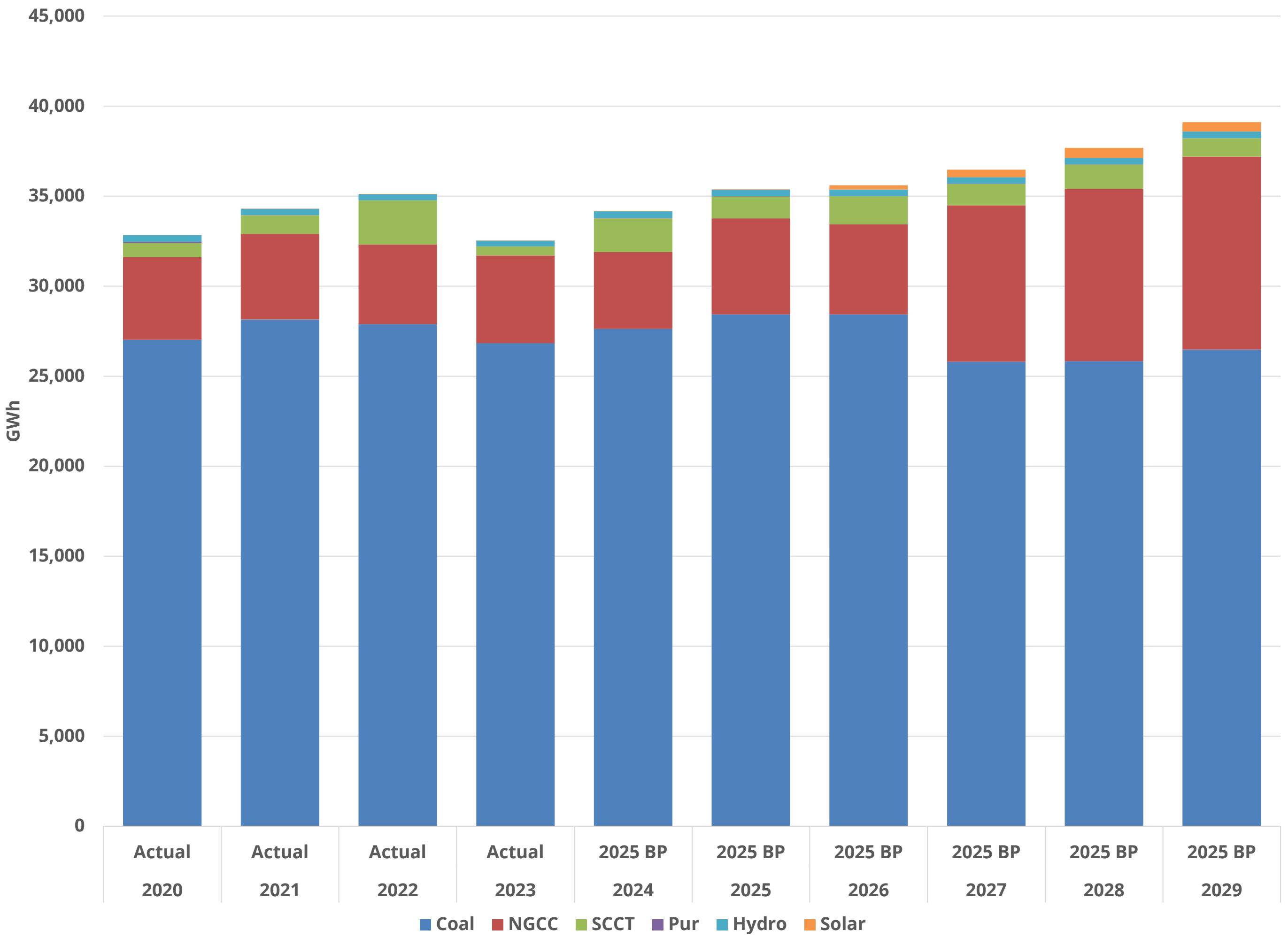
Mill Creek coal and Cane Run 7 primarily account for new economic development load and Mill Creek 1 retirement



Coal share declines through the planning period with MC5 in 2027



Energy Mix %

Year	Coal	NGCC	SCCT	Hydro	Solar
2020	82	14	2	1	0
2021	82	14	3	1	0
2022	79	13	7	1	0
2023	82	15	2	1	0
2024	81	12	5	1	0
2025	80	15	3	1	0
2026	80	14	4	1	1
2027	71	24	3	1	1
2028	69	25	4	1	1
2029	68	27	3	1	1

2025 BP in 2024: 6+6

Key takeaways

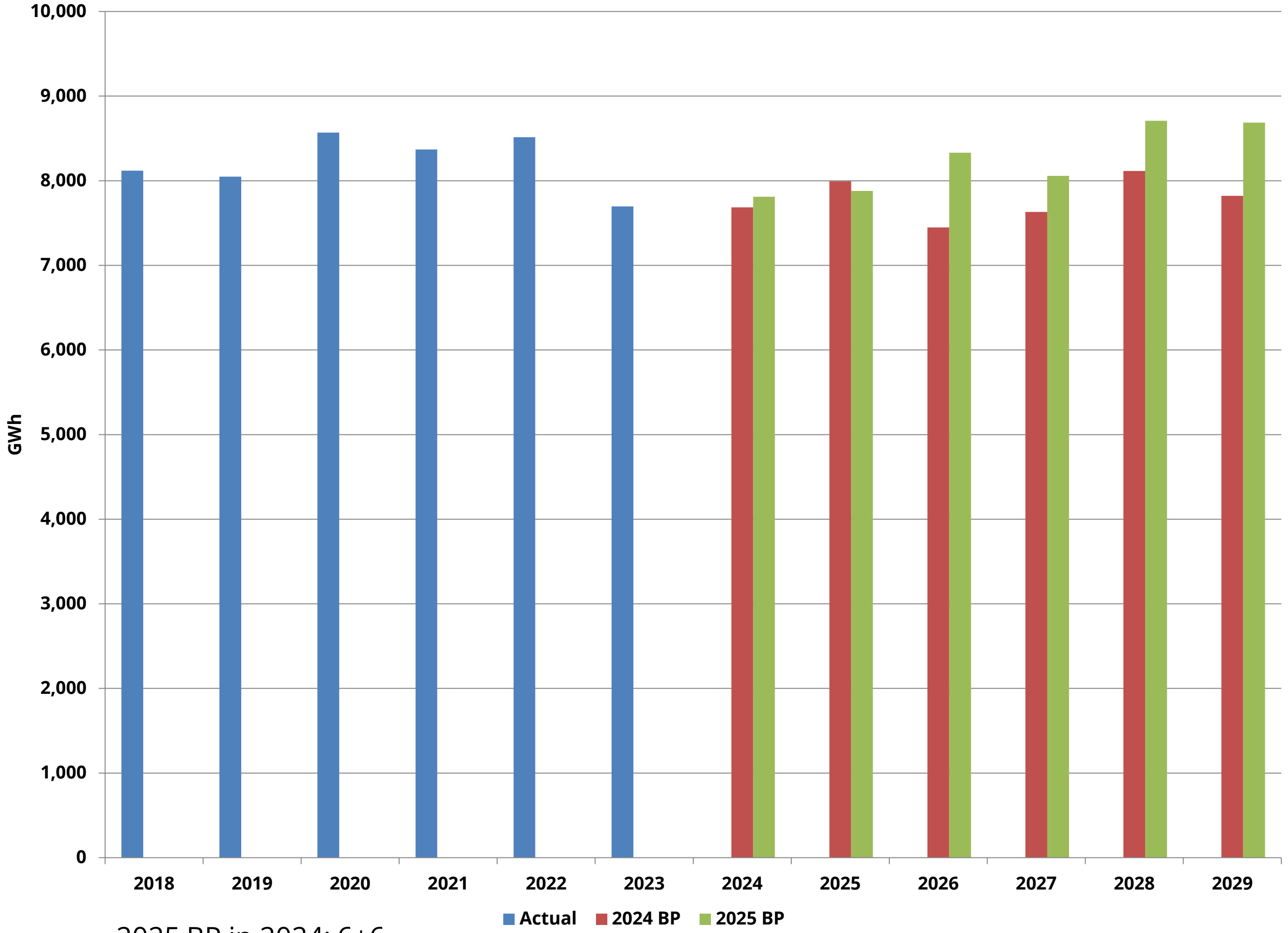
- Decreased fuel prices result in lower native load production costs despite increasing native load
- New resources decrease coal % of energy mix over planning period
- CCR revenues projected to be $60-70 million per year
- OSS contribution projected to be $7-13 million per year
- No near-term projects associated with ELG or Section 111(b) and 111(d) during Business Planning period
- Ghent 2 SCR assumed in 2028 along with more stringent Group 3 ONO_x emission allowance pricing

Appendix

Resource plans

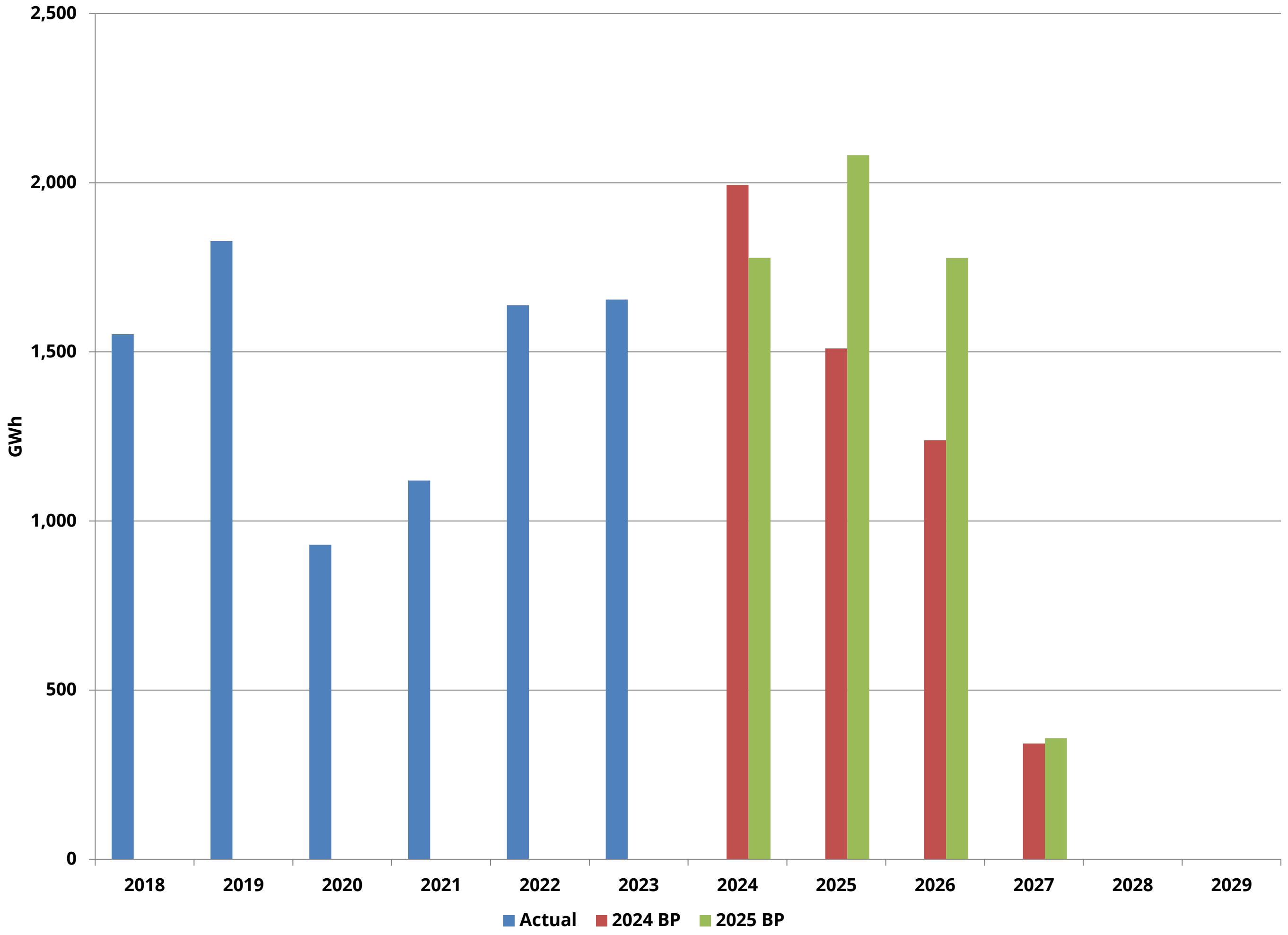
- Business Plan focuses on 5-year period from 2025 to 2029
- Resource Plans consistent with 2022 CPCN order, 2024 IRP, and recent updates
- Solar PPAs terminated by developers, canceled due to price reopeners, or delayed indefinitely
- Retirements
  - — Mill Creek 1 at end of 2024
  - — Haefling 1-2 and Paddy's Run 12 in 2025
  - — Mill Creek 2 in 2027
- Additions
  - — Mill Creek 5 in 2027
  - — Brown BESS in 2027
  - — 120 MW Mercer Co. asset in 2026
  - — 120 MW Marion Co. asset in 2027
  - — Ghent 2 SCR in 2028
  - — 400 MW BESS in 2028
  - — Brown 12 in 2030
  - — NGCC in 2031

Trimble coal generation increases due to improved EFOR and heat rates, no solar PPAs, and increased load



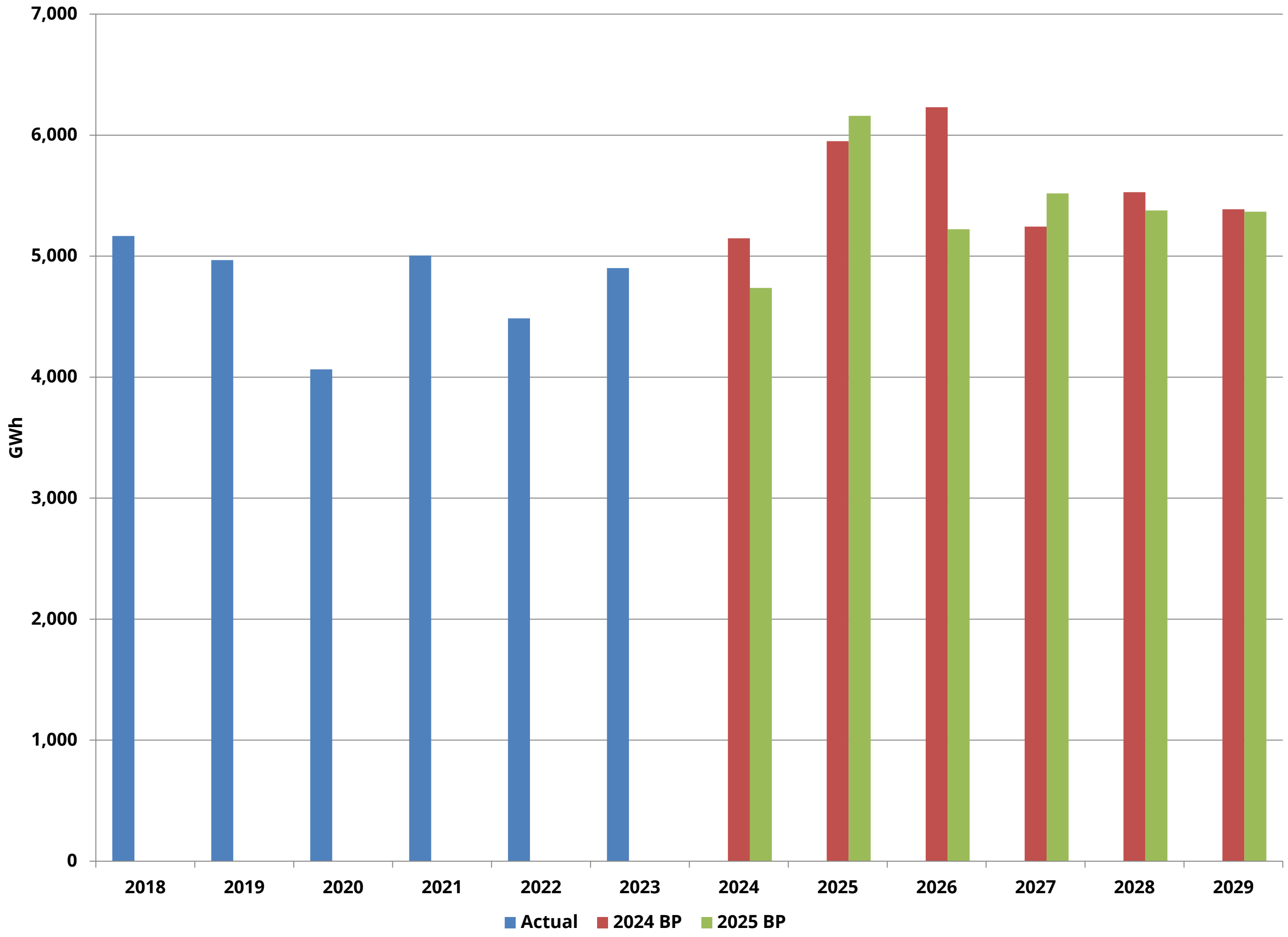
2025 BP in 2024: 6+6

Mill Creek 2 generation increases due to lower ONO$_x$ prices



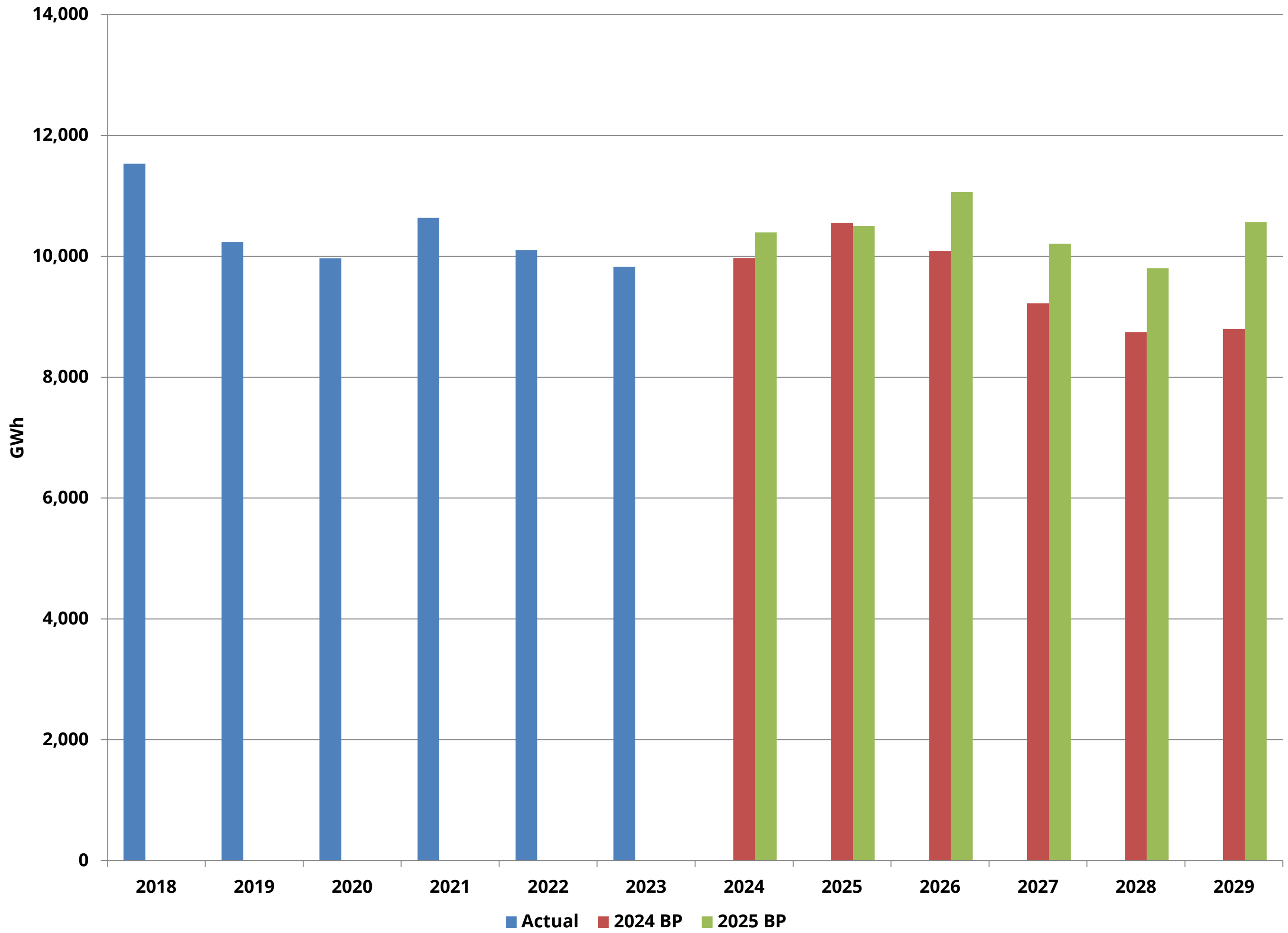
2025 BP in 2024: 6+6

Mill Creek 3-4 generation decreases due to operational constraints and maint schedule; increases due to improved heat rates and no solar PPAs



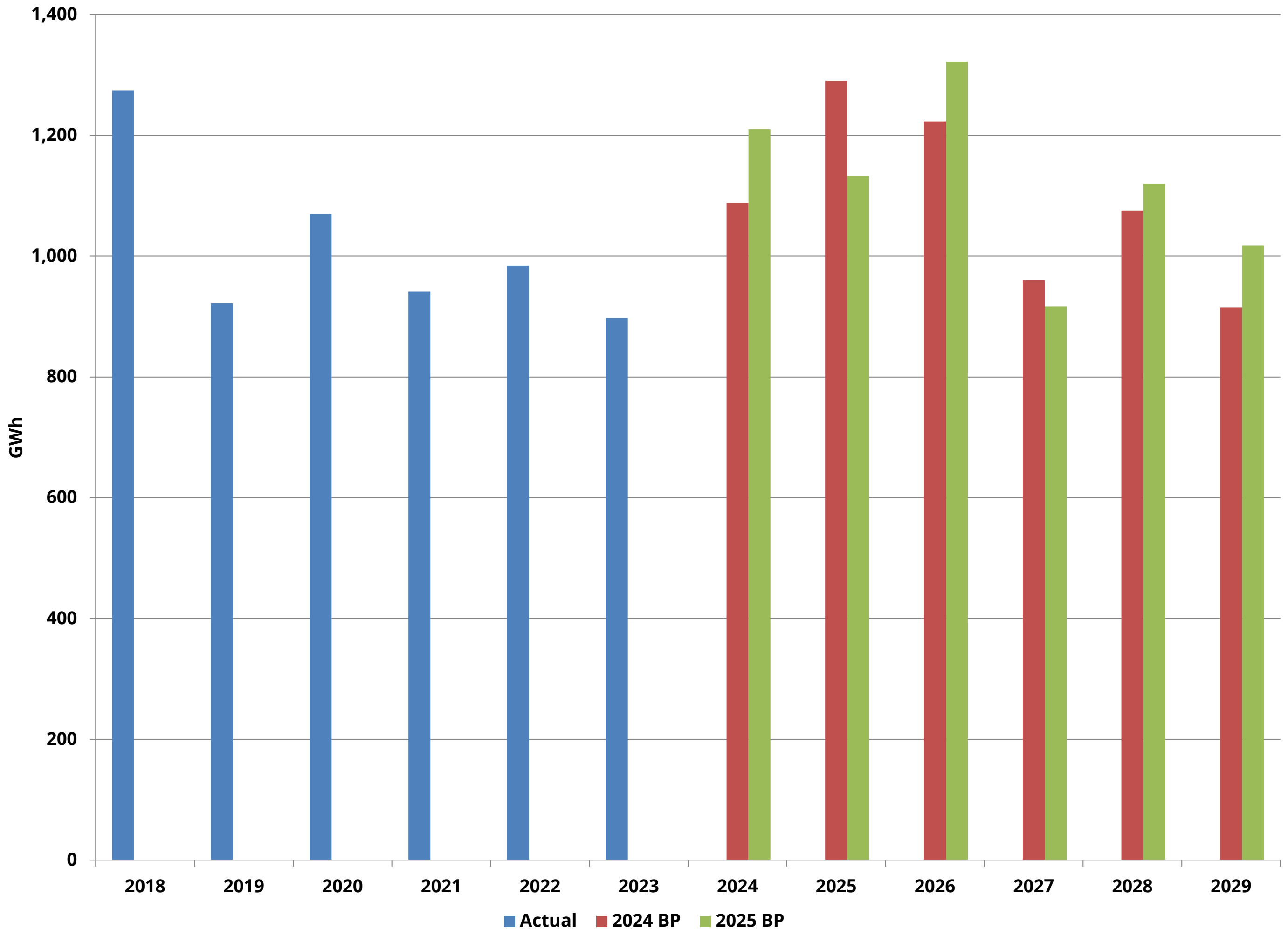
2025 BP in 2024: 6+6

Ghent generation increases due to lower ONO$_x$ prices, updated CCR prices, no solar PPAs, and increased load



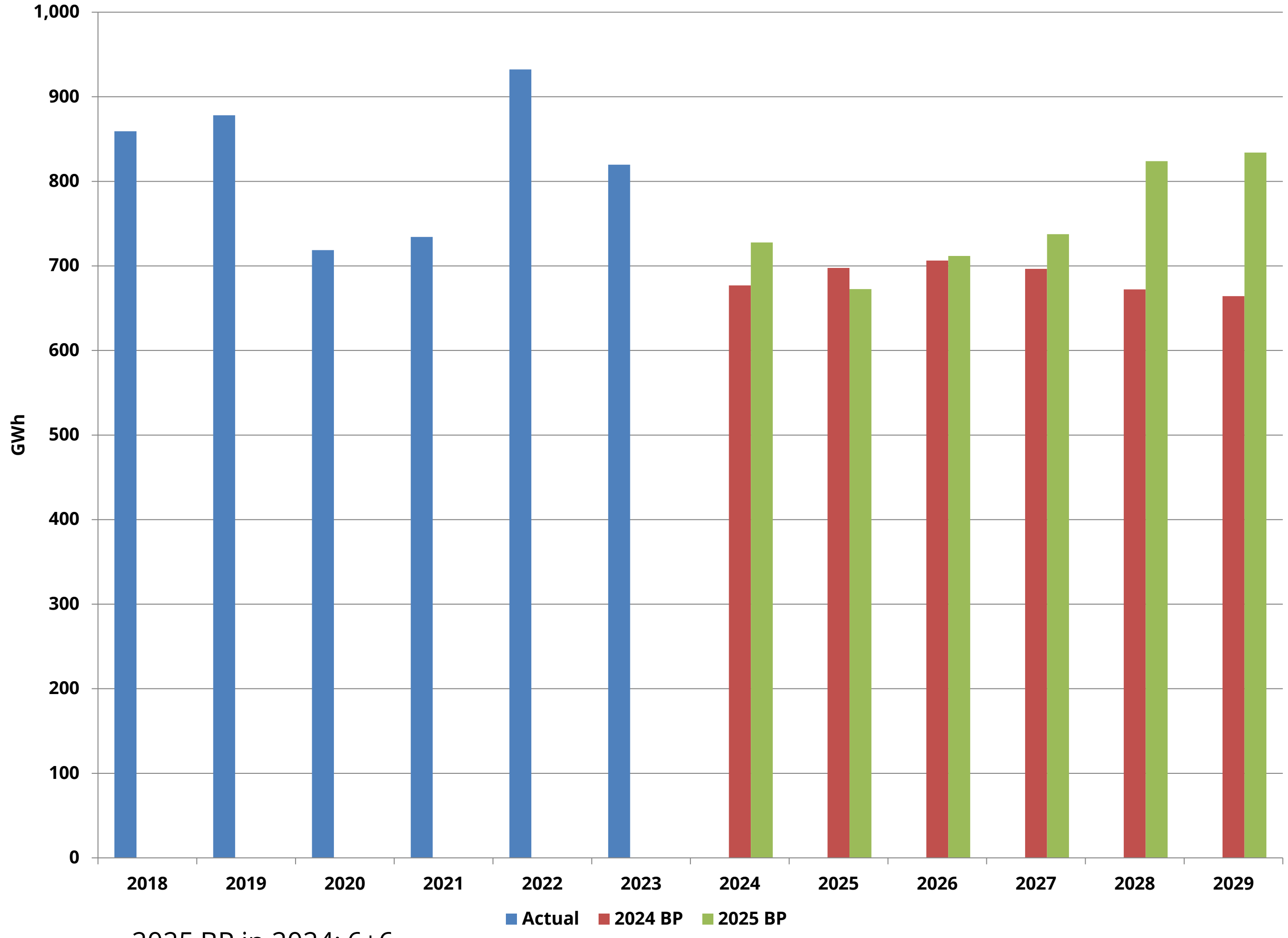
2025 BP in 2024: 6+6

Brown 3 generation decreases due to lower ONO$_x$ prices and higher EFOR



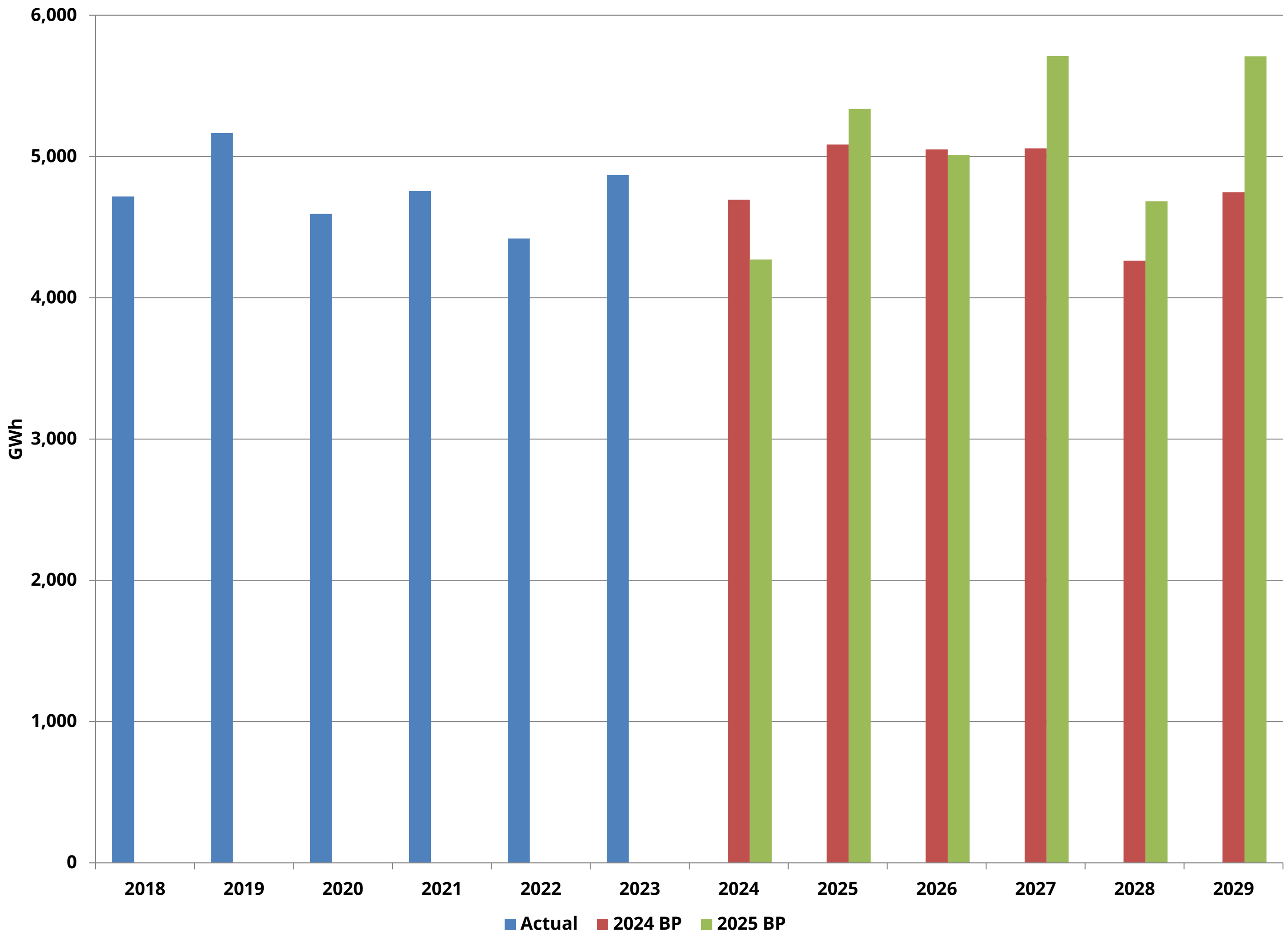
2025 BP in 2024: 6+6

OVEC generation increases due to updated OVEC prices, no solar PPAs, and increased load



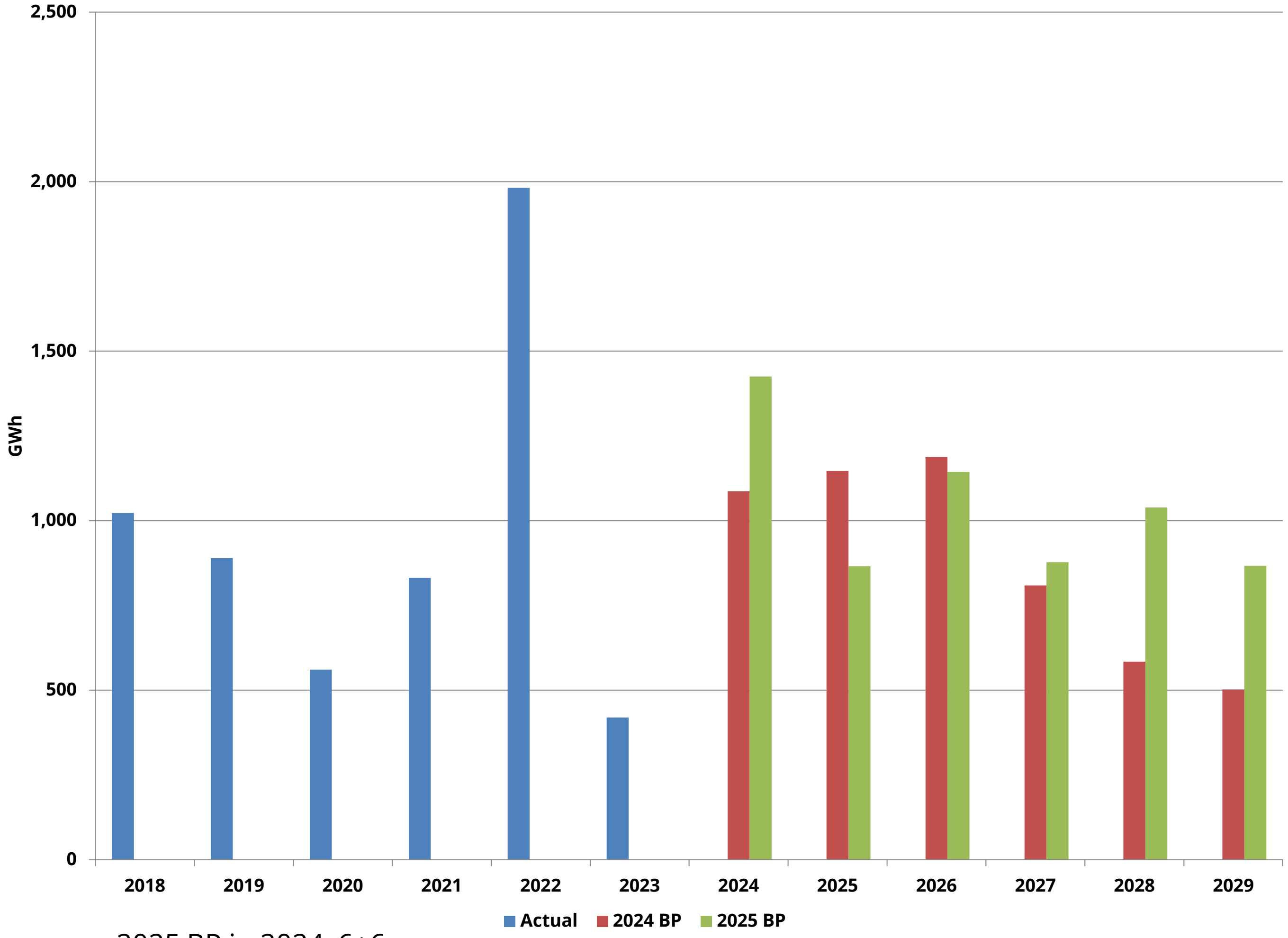
2025 BP in 2024: 6+6

Cane Run 7 generation increases due to increased capacity and load



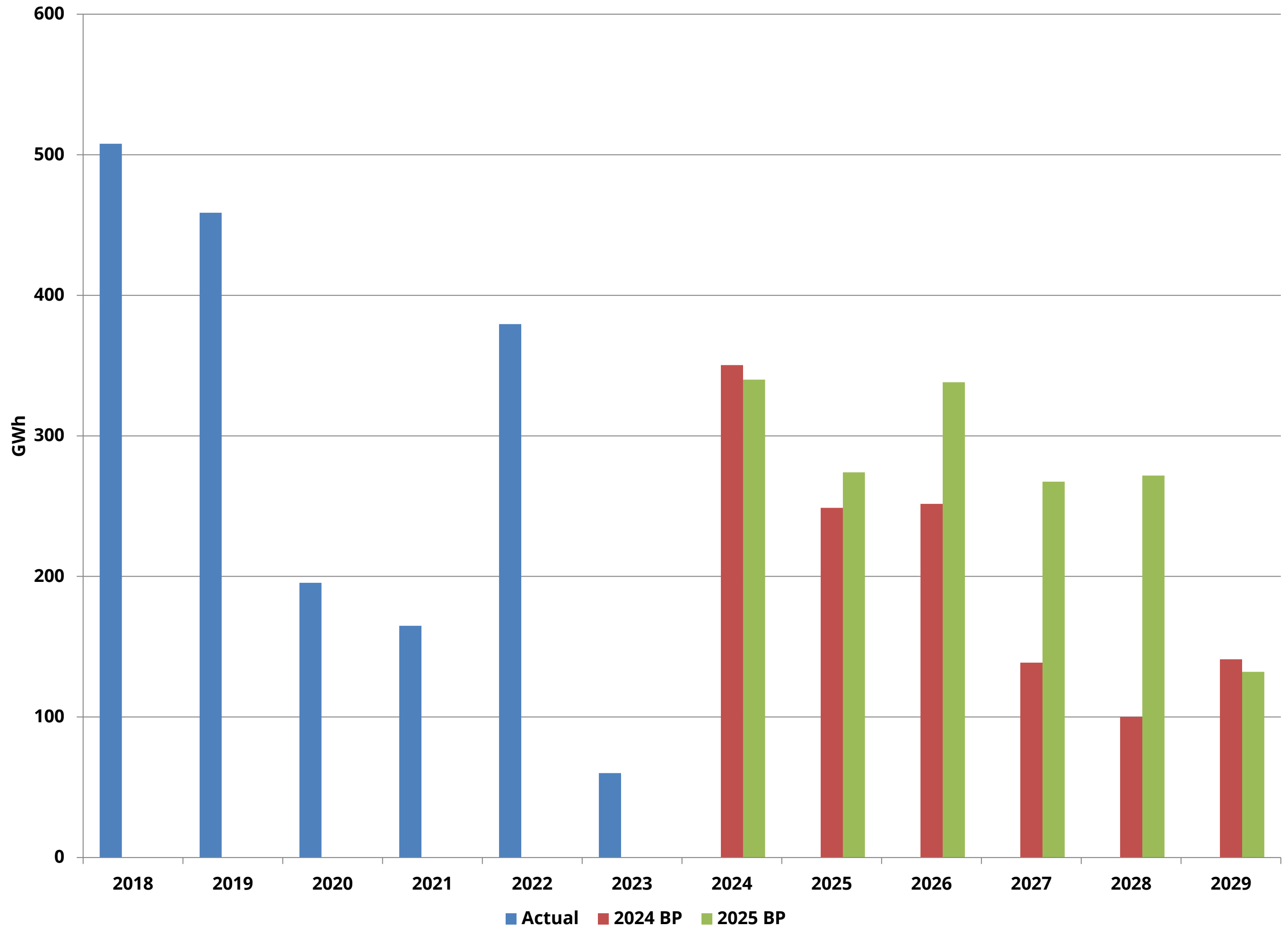
2025 BP in 2024: 6+6

Trimble CT generation mostly increases due to no solar PPAs, increased load, updated maint schedule, and lower gas prices



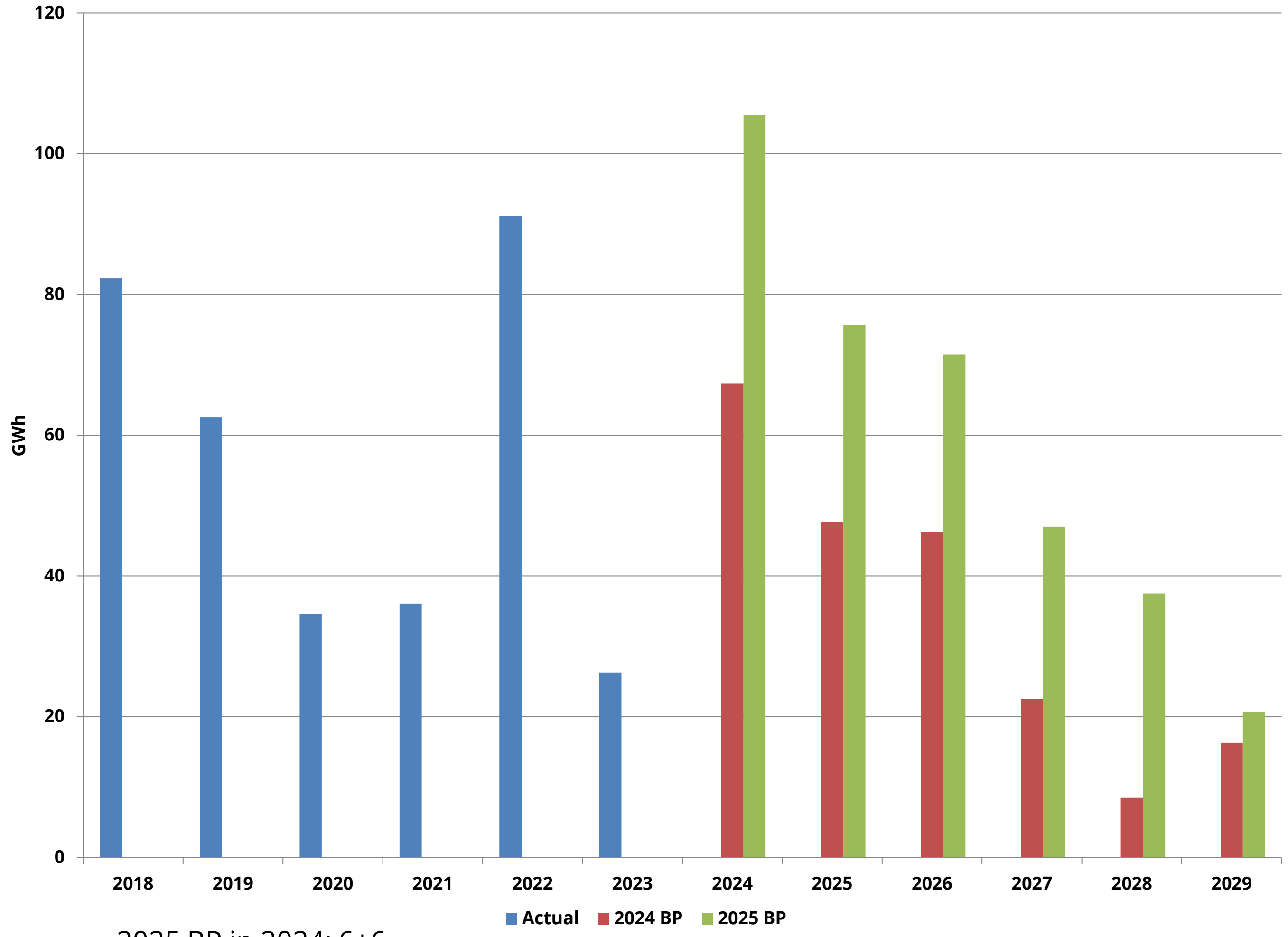
2025 BP in 2024: 6+6

Brown CT generation increases due to no solar PPAs, increased load, updated maint schedule, and lower gas prices



2025 BP in 2024: 6+6

Paddy's Run generation increases due to no solar PPAs, increased load, updated maint schedule, and lower gas prices



2025 BP in 2024: 6+6

Seasonally-adjusted capacity factor by unit

	History							6+6	2024 BP					2025 BP				
(%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2025	2026	2027	2028	2029
Brown 3	28	35	25	29	26	27	25	33	36	34	26	30	25	31	36	25	31	28
Ghent 1	74	72	65	64	65	65	64	65	68	76	61	65	55	59	75	58	56	55
Ghent 2	70	80	63	59	60	52	61	62	50	37	42	32	41	68	66	58	62	69
Ghent 3	61	53	56	61	67	67	56	65	66	68	56	58	61	60	64	69	62	70
Ghent 4	78	70	60	53	61	56	53	54	67	59	60	53	53	62	59	58	52	57
Mill Creek 1	64	75	57	65	51	47	39	37										
Mill Creek 2	65	60	70	36	43	63	64	68	58	48	13			80	68	14		
Mill Creek 3	76	72	54	51	63	61	68	56	71	79	65	74	64	87	66	79	70	70
Mill Creek 4	70	64	74	55	68	57	61	66	83	83	71	70	76	75	70	67	70	70
OVEC	53	56	57	46	48	60	53	47	45	46	45	43	43	44	46	48	53	54
Trimble County 1	67	83	76	82	69	82	77	83	63	72	72	78	73	64	85	76	83	81
Trimble County 2	74	69	73	77	83	76	67	65	80	67	69	72	71	78	71	73	78	80
Cane Run 7	60	79	86	77	79	74	81	71	84	80	78	66	74	88	79	88	72	88
Mill Creek 5											47	80	77			52	85	87
Brown 5, 8-11	3	5	4	1	1	2	0.4	3	2	2	1	1	1	3	4	3	3	0.4
Brown 6-7	2	9	9	4	4	9	1	6	5	6	3	2	2	4	5	4	5	4
Paddy's Run 13	5	6	4	2	3	6	2	7	3	3	2	1	1	5	5	3	3	1
Trimble CTs	9	12	10	6	9	22	5	16	13	13	9	7	6	10	13	10	12	10
Haefling 1-2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1										
Paddy's Run 12	0.1	0.0	0.2	0.0	0.0	0.2	0.0	0.0										
Dix Dam	20	52	36	43	30	21	15	25	31	31	31	31	31	30	30	30	30	30
Ohio Falls	32	22	29	27	30	31	31	33	31	31	31	31	31	31	31	31	31	31
Brown Solar	20	19	20	19	19	19	19	19	19	19	19	19	19	19	19	19	19	20
Mercer Co Solar										19	26	25	26		27	25	25	24
Marion Co Solar											28	27	28			24	25	24

Maintenance schedule updates

Maintenance Weeks

	2025 BP					2024 BP					2025 BP - 2024 BP					
	2025	2026	2027	2028	2029	2025	2026	2027	2028	2029	2025	2026	2027	2028	2029	Totals
Brown 3	4	1	8	1	4	4	1	2	-	3	-	-	6	1	1	8
Ghent 1	6	-	6	5	8	6	-	6	4	8	-	-	-	1	-	1
Ghent 2	-	5	8	4	-	-	5	1	-	-	-	-	7	4	-	11
Ghent 3	7	8	1	4	1	5	1	8	5	1	2	7	(7)	(1)	-	1
Ghent 4	1	7	4	8	5	3	7	4	8	5	(2)	-	-	-	-	(2)
Mill Creek 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mill Creek 2	3	4	-	-	-	2	4	-	-	-	1	-	-	-	-	1
Mill Creek 3	-	5	2	8	1	5	1	8	1	6	(5)	4	(6)	7	(5)	(5)
Mill Creek 4	7	2	8	7	1	1	1	6	6	1	6	1	2	1	-	10
Mill Creek 5	-	-	-	2	2	-	-	-	-	-	-	-	-	2	2	4
Trimble County 1	12	2	4	2	4	18	3	4	2	4	(6)	(1)	-	-	-	(7)
Trimble County 2	3	10	5	5	5	2	9	5	5	5	1	1	-	-	-	2
Cane Run 7	2	6	1	9	1	3	3	1	8	1	(1)	3	-	1	-	3
Totals	**45**	**50**	**47**	**55**	**32**	**49**	**35**	**45**	**39**	**34**	**(4)**	**15**	**2**	**16**	**(2)**	**27**
MW-Maint Wks*	**21,447**	**26,284**	**23,504**	**28,636**	**15,494**	**22,570**	**18,284**	**22,296**	**21,619**	**16,976**	**(1,123)**	**7,999**	**1,208**	**7,017**	**(1,482)**	**13,620**

*Coal + NGCC Only

Variable O&M increases driven by higher cost of hydrated lime for SO_3 reduction and limestone for FGD use

Total VO&M ($/MWh)	2025			2026			2027			2028		
	2024 BP	2025 BP	Diff	2024 BP	2025 BP	Diff	2024 BP	2025 BP	Diff	2024 BP	2025 BP	Diff
Brown 3	2.27	2.48	0.21	2.35	2.59	0.24	2.43	2.69	0.26	N/A	2.77	N/A
Ghent 1	2.01	2.10	0.08	2.08	2.21	0.13	2.15	2.30	0.15	2.22	2.36	0.14
Ghent 2	1.72	1.74	0.01	1.78	1.82	0.04	1.84	1.90	0.07	N/A	1.97	N/A
Ghent 3	2.23	2.20	(0.03)	2.31	2.32	0.02	2.38	2.42	0.04	2.47	2.48	0.02
Ghent 4	2.15	2.07	(0.09)	2.22	2.17	(0.05)	2.29	2.26	(0.03)	2.37	2.32	(0.05)
Mill Creek 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	1.06	1.22	0.16	1.09	1.28	0.19	1.11	1.31	0.19	N/A	N/A	N/A
Mill Creek 3	1.80	1.94	0.14	1.86	2.06	0.19	1.95	2.12	0.17	2.02	2.15	0.13
Mill Creek 4	1.80	2.01	0.20	1.86	2.12	0.26	1.95	2.19	0.24	2.02	2.23	0.20
Trimble 1	1.97	2.33	0.36	2.02	2.46	0.43	2.09	2.57	0.48	2.15	2.64	0.49
Trimble 2	2.43	2.50	0.08	2.52	2.64	0.12	2.62	2.76	0.14	2.72	2.86	0.14

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Heat rates reflect results of performance testing using granular PI data

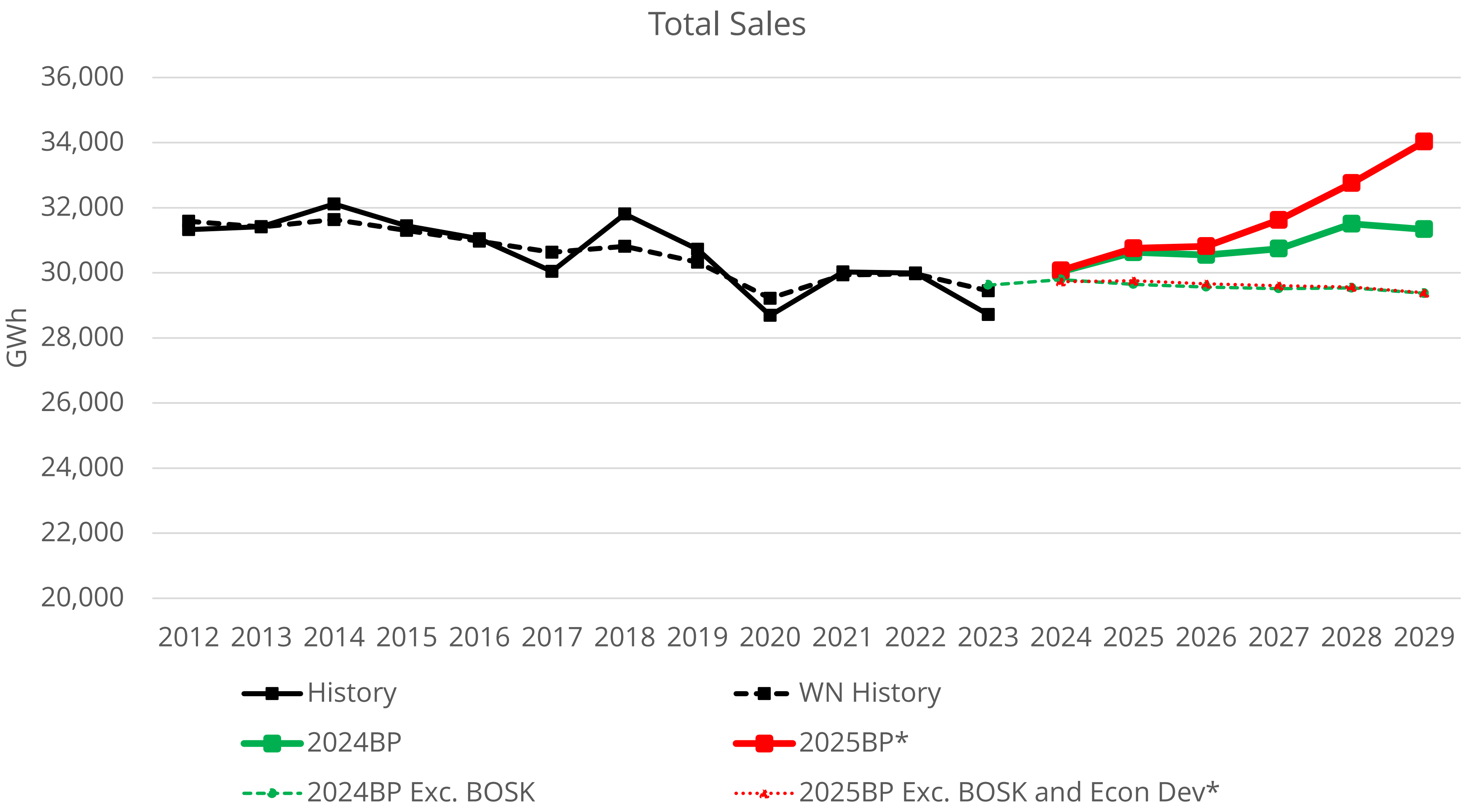
	Summer Net Heat Rates at Max Load (Btu/kWh)			Winter Net Heat Rates at Max Load (Btu/kWh)			
	2024 BP	2025 BP	Percent Change	2024 BP	2025 BP	Percent Change	Average Heat Rate, 2023 KPIs
BR3	10,987	10,975	-0.1%	11,092	11,351	2.3%	11,749
GH1	10,480	10,828	3.3%	10,563	10,699	1.3%	10,824
GH2	10,299	10,577	2.7%	10,618	10,480	-1.3%	10,850
GH3	10,454	10,546	0.9%	10,484	10,665	1.7%	10,932
GH4	10,518	10,764	2.3%	10,612	10,877	2.5%	10,837
MC1	10,389	10,389	0.0%	10,503	10,503	0.0%	10,631
MC2	10,423	10,240	-1.8%	10,564	10,495	-0.7%	10,618
MC3	10,466	10,228	-2.3%	10,661	10,336	-3.0%	10,351
MC4	10,381	10,381	0.0%	10,283	10,283	0.0%	9,888
TC1	10,357	10,205	-1.5%	10,354	10,402	0.5%	10,497
TC2	9,260	9,214	-0.5%	9,254	9,203	-0.5%	9,393
CR7	6,721	6,553	-2.5%	6,683	6,491	-2.9%	6,602

Notes:

-Values shown represent net heat rates (in Btu/kWh).

-Summer and winter heat rates reflect values at maximum load. KPI heat rates reflect average observed values.

Total sales 0.4% higher in 2025; major accounts and economic development drive growth thereafter



*2024 is 5 months of actuals and 7 months of forecast.

Peak load and energy comparison

Peak Delta (2025 BP - 2024 BP)

MW	2025	2026	2027	2028	2029
Jan	92	98	176	192	319
Feb	31	40	151	134	275
Mar	39	54	114	129	352
Apr	(4)	28	(131)	104	217
May	42	54	106	119	255
Jun	(50)	(22)	70	47	149
Jul	(39)	(13)	128	122	370
Aug	(37)	(8)	83	119	344
Sep	(59)	(26)	124	105	289
Oct	41	73	101	198	547
Nov	127	151	302	295	501
Dec	70	85	137	216	439
Peak	**(37)**	**(8)**	**83**	**119**	**344**

Energy Delta (2025 BP - 2024 BP)

GWh	2025	2026	2027	2028	2029
Jan	31	32	89	101	196
Feb	11	15	65	77	162
Mar	(9)	(1)	52	62	159
Apr	6	18	63	70	165
May	16	29	75	81	180
Jun	(15)	1	46	50	146
Jul	(24)	(4)	80	98	250
Aug	(12)	9	80	112	264
Sep	(16)	(0)	55	99	245
Oct	8	21	65	124	274
Nov	42	54	86	155	299
Dec	27	37	61	145	292
Total	**64**	**210**	**817**	**1,174**	**2,633**

SVP Eng & Construction / Generation Engineering / TD&S Engineering & Construction / Gas Engineering, Construction, and Integrity Management
LG&E and KU Utilities
2025 Operating Plan

Table of Contents

Major Assumptions

- Budgeted costs for SVP Engineering & Construction (E&C) originate from PPLS allocations
- Transmission, Distribution & Substation Engineering (TD&S Eng.) and Gas Engineering, Construction, & Integrity Management (Gas Eng., Const., & Intg. Mgmt) labor is primarily budgeted to Capital projects in the appropriate lines of business
  - E&C O&M budget includes compliance support and employee-related expenses such as training, cell phones, etc.
  - O&M expenses related to Gas Line Inspections remain in the Gas line of business
  - O&M related to circuit inspections (managed by TD&S Constr. & Proj. Mgmt) remains in the Transmission line of business
- Generation Engineering:
  - Capital projects managed by the Generation Engineering (GE) department roll up to the Generation organization. Generation Engineering budgets approximately 14% of labor to capital projects.
  - All O&M stays in the E&C organization, including any O&M worked by GE employees for the various plants, O&M outages, etc.

Savings/Efficiencies/Cost Reduction Measures

- In mid-2024, the company created the centralized Engineering & Construction organization to drive consistent engineering practices enterprise-wide
  - Enables the company to leverage best practices across the enterprise in the delivery of larger, complex projects within our overall infrastructure investment plans
  - Successful execution of construction plans will modernize and expand the generation fleet and energy delivery infrastructure
- Plan includes opex reductions in employee training and travel

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
SVP Engineering & Construction					
Labor (PPL)	$ 1,714	$ 1,843	$ 1,927	$ 1,995	$ 2,074
Outside Services (PPL)	$ 186	$ 165	$ 146	$ 147	$ 148
Other Non-Labor (PPL)	$ 165	$ 166	$ 169	$ 169	$ 170
Total O&M	**$ 2,065**	**$ 2,174**	**$ 2,242**	**$ 2,311**	**$ 2,392**
TD&S Engineering & Construction					
Labor	$ 2,163	$ 2,223	$ 2,286	$ 2,353	$ 2,429
Outside Services	$ 260	$ 225	$ 260	$ 261	$ 269
Employee Expenses	$ 355	$ 485	$ 490	$ 496	$ 509
Other Non-Labor	$ 171	$ 186	$ 206	$ 206	$ 213
Total O&M	**$ 2,950**	**$ 3,119**	**$ 3,242**	**$ 3,317**	**$ 3,419**
Gas Engineering, Construction, and Integrity Management					
Labor	$ 528	$ 546	$ 564	$ 579	$ 602
Employee Expenses	$ 127	$ 182	$ 190	$ 194	$ 198
Other Non-Labor	$ 14	$ 15	$ 15	$ 15	$ 16
Total O&M	**$ 669**	**$ 743**	**$ 770**	**$ 789**	**$ 815**

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Generation Engineering					
Labor	$ 12,063	$ 12,397	$ 12,779	$ 13,116	$ 13,551
Supplemental Contractor Labor	$ 389	$ 395	$ 401	$ 503	$ 505
Outside Services	$ 2,705	$ 3,087	$ 3,249	$ 3,048	$ 2,667
Employee Expenses	$ 253	$ 384	$ 393	$ 395	$ 395
Other Non-Labor	$ 822	$ 823	$ 1,005	$ 910	$ 877
Total O&M	**$ 16,232**	**$ 17,086**	**$ 17,827**	**$ 17,972**	**$ 17,994**

Annual Cost of Sales Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Generation Engineering					
Labor (ECR)	$ 117	$ 121	$ 125	$ 129	$ 133
Total COS	**$ 117**	**$ 121**	**$ 125**	**$ 129**	**$ 133**

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
SVP Engineering & Construction	**1**	**1**	**1**	**1**	**1**
TD&S Engineering & Construction					
T&D Lines Engineering	13	13	13	13	13
TD&S Eng Project Management	6	6	6	6	6
TD&S Eng Construction Management	19	19	19	19	19
T&D Substation Engineering	37	37	37	37	37
Substation Compliance Engineering	6	6	6	6	6
Co-Ops/Interns	11	11	11	11	11
Total	**92**	**92**	**92**	**92**	**92**
Gas, Eng. Const. & Intg Mgmt					
Gas Storage Integrity & Compliance	4	4	4	4	4
Gas Distribution Integrity & Compliance	3	3	3	3	3
Gas Transmission Integrity & Compliance	8	8	8	8	8
Gas Engineering	11	11	11	11	11
Co-Ops/Interns	4	4	4	4	4
Total	**30**	**30**	**30**	**30**	**30**

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Generation Engineering					
Director Generation Engineering	1	1	1	1	1
Compliance & Document Mgmt	11	11	11	11	11
System Lab & Env. Compl.	9	9	9	9	9
Gen Fleet Engineering	1	1	1	1	1
Civil Engineering	5	5	5	5	5
Electrical Engineering	5	5	5	5	5
Mechanical Engineering	7	7	7	7	7
Performance Engineering	7	7	7	7	7
Turbine Generator Specialist	2	2	2	2	2
MC Engineering & Technical Services	10	10	10	10	10
TC Engineering & Technical Services	12	12	12	12	12
GH Engineering & Technical Services	8	8	8	8	8
Co-Ops/Interns	10	10	10	10	10
Total	**88**	**88**	**88**	**88**	**88**

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
TD&S Engineering & Construction*					
T&D Lines Engineering	4	4	4	4	4
TD&S Eng - Project Management	25	25	25	25	25
TD&S Eng - Construction Management	230	325	350	350	350
T&D Substation Engineering	4	4	4	4	4
Substation Compliance Engineering	4	4	4	4	4
Total	**92**	**92**	**92**	**92**	**92**
Gas, Eng. Const. & Intg Mgmt	**0**	**0**	**0**	**0**	**0**
Generation Engineering					
Compliance & Document Mgmt	1	1	1	2	2
System Lab & Env. Compl.	1	1	1	1	1
Performance Engineering	1	1	1	1	1
Gen Fleet Engineering	1	1	1	1	1
Total	**4**	**4**	**4**	**5**	**5**

* *Dollars associated with supplemental contractors in the Transmission, Distribution & Substation Engineering & Construction org are held within the capital projects in the lines of business*

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
SVP Engineering & Construction					
PPL Outside Services	$ 186	$ 165	$ 146	$ 147	$ 148
PPL Other Non-Labor	$ 165	$ 166	$ 169	$ 169	$ 170
Total O&M	**$ 351**	**$ 331**	**$ 315**	**$ 316**	**$ 318**
TD&S Engineering & Construction					
Outside Services					
Other 3rd Party Labor	$ 260	$ 225	$ 260	$ 261	$ 269
Employee Expenses					
Training, Travel, & Meals	$ 171	$ 297	$ 300	$ 304	$ 311
Cellular Services	$ 112	$ 114	$ 116	$ 118	$ 121
Vehicles	$ 64	$ 65	$ 65	$ 67	$ 69
Dues & Subscriptions	$ 8	$ 8	$ 8	$ 8	$ 8
Other Non-Labor					
Computer Purchases	$ 86	$ 83	$ 102	$ 102	$ 105
Purchased Material	$ 72	$ 89	$ 89	$ 89	$ 92
Other	$ 13	$ 14	$ 15	$ 15	$ 16
Total O&M	**$ 787**	**$ 897**	**$ 956**	**$ 964**	**$ 990**
Gas Engineering, Construction, and Integrity Management					
Employee Expenses					
Training, Travel, & Meals	$ 76	$ 130	$ 137	$ 139	$ 142
Vehicles	$ 31	$ 32	$ 32	$ 33	$ 34
Cellular Services	$ 21	$ 21	$ 21	$ 22	$ 22
Other Non-Labor					
Other	$ 8	$ 9	$ 9	$ 9	$ 9
Purchased Material	$ 6	$ 6	$ 6	$ 6	$ 7
Total O&M	**$ 141**	**$ 197**	**$ 205**	**$ 209**	**$ 214**

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Generation Engineering					
Supplemental Contractor Labor	$ 389	$ 395	$ 401	$ 503	$ 505
Outside Services					
Other 3rd Party Labor	$ 2,213	$ 2,551	$ 2,648	$ 2,409	$ 2,026
Engineering & Consulting	$ 492	$ 536	$ 601	$ 639	$ 640
Employee Expenses					
Training, Travel, & Meals	$ 164	$ 293	$ 299	$ 299	$ 299
Cellular Services	$ 55	$ 56	$ 59	$ 60	$ 60
Dues & Subscriptions	$ 23	$ 23	$ 23	$ 24	$ 24
Vehicles	$ 11	$ 11	$ 12	$ 12	$ 12
Other Non-Labor					
Computer Purchases	$ 432	$ 444	$ 612	$ 517	$ 487
Purchased Material	$ 339	$ 329	$ 342	$ 342	$ 339
Material & Equipment (Installed)	$ 40	$ 40	$ 40	$ 40	$ 40
Other	$ 11	$ 11	$ 11	$ 11	$ 11
Total O&M	**$ 4,169**	**$ 4,689**	**$ 5,049**	**$ 4,856**	**$ 4,444**

Corporate Cost Center
LG&E and KU Utilities
2025 Operating Plan

PPL companies

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2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
O&M Expenses Only:					
Amortization of Regulatory Assets	$ 1,765	$ 17,070	$ 18,040	$ 18,712	$ 17,445
A&G Transferred Credit	(7,988)	(8,303)	(8,646)	(8,834)	(9,059)
Outage Amortization	7,583	7,583	6,835	6,088	3,044
Incentive Compensation	139	89	10	-	-
Insurance Expense	26,571	31,560	34,894	37,959	41,313
Bad Debt Expense	8,833	8,961	9,215	9,558	9,861
PPLS Allocation	1,958	2,302	2,324	2,342	2,363
Management Challenge	(9,479)	(15,120)	(52,014)	(62,472)	(74,049)
Other[1]	3,434	5,654	7,770	9,703	11,139
Total O&M	**$ 32,815**	**$ 49,798**	**$ 18,429**	**$ 13,055**	**$ 2,056**

[1]Other primarily includes amounts related to Cloud Software and Gas Line Inspection amortization of $3,707k in 2025, $5,933k in 2026, $8,056k in 2027, $9,995k in 2028 and $11,438k in 2029.

Case Nos. 2025-00113 and 2025-00114
Attachment to Filing Requirement
Tab 16 - 807 KAR 5:001 Section 16(7)(c) Item I

Metts

LG&E KU
PPL companies

2025-2029
Annual Cost of Sales Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
GSC Bad Debt	$ 247	$ 269	$ 278	$ 278	$ 271
Total COS	**$ 247**	**$ 269**	**$ 278**	**$ 278**	**$ 271**

O&M Annual Expense Reconciliation ($000)

	2025	2026	2027	2028
2025 Business Plan	$ 32,815	$ 49,798	$ 18,429	$ 13,055
2024 Business Plan	23,658	85,155	50,269	57,078
Change	$ (9,157)	$ 35,357	$ 31,840	$ 44,023
Drivers:				
Amortization of Regulatory Assets	$ (0)	$ (12,265)	$ (12,589)	$ (12,799)
A&G Transferred Credit	(1,147)	(1,010)	(960)	(975)
Outage Amortization	-	-	(125)	-
Incentive Compensation	(68)	(80)	(10)	-
Insurance Expense	2,942	864	760	1,281
Bad Debt Expense	379	1,019	1,285	1,200
PPLS Allocation	344	19	24	25
Management Challenge	(10,236)	50,390	49,094	62,856
Other	(1,370)	(3,579)	(5,641)	(7,565)
Total Drivers	$ (9,157)	$ 35,357	$ 31,840	$ 44,023

Power Generation
LG&E and KU Utilities
2025 Operating Plan

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Major Assumptions

- **Generation Unit Retirements:**
  - Mill Creek 2 : 2/28/2027
- **New Generation In-Service:**
  - Mill Creek 5 : 6/30/2027
  - Mercer Solar : 6/30/2026
  - Marion Solar : 6/30/2027
  - Brown BESS : 1/31/2027
- **Major Outages by Unit:**
  - 2025: Trimble County 1
  - 2026: Trimble County 2, Ghent 3
  - 2027: Brown 3, Ghent 2
  - 2028: Ghent 4, Mill Creek 3, Cane Run 7, Paddy's Run 13
  - 2029: Ghent 1, Paddy's Run 13 (continued)

Savings/Efficiencies/Cost Reduction Measures

- Outage savings through reduced scopes, reduced frequency, shorter durations, and deferrals into future years.
  - 2025 Deferrals - Cane Run 7, Mill Creek 3, Trimble 2, Paddy's Run, Ghent 4
- Labor savings driven by headcount reductions. (Reduce operating rounds and maintenance on non-critical equipment. Eliminate currently held backfills and absorb attrition of projected employee retirements.)
- Supplemental contractor savings driven by reduction in headcount.
- Maintenance Savings through reduced frequency of equipment overhauls and less preventative maintenance across the entire fleet.

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Coal Outage	$ 61,256	$ 115,069	$ 113,552	$ 129,585	$ 97,095
NGCC Outage	$ 754	$10,861	$2,686	$41,270	$3,030
CT Outage	$ 1,486	$7,013	$29,975	$28,455	$65,976
Coal Reliability	$ 41,391	$40,903	$34,584	$43,180	$50,369
NGCC Reliability	$ 1,957	$3,423	$3,327	$3,605	$1,060
CT Reliability	$ 5,696	$2,755	$4,974	$3,095	$5,199
Hydro Reliability	$ 498	$1,200	$747	$105	$700
Environmental Non-Mech	$ 4,790	$17,794	$8,196	$8,802	$9,239
ECR Mechanism	$ 3,053	$490	$487	$883	$487
All Other	$ 12,256	$10,434	$5,196	$6,594	$16,102
Total Capital	$ 133,137	$ 209,942	$ 203,724	$ 265,574	$ 249,257
2024 Plan	$126,401	$175,213	$199,534	$244,228	
Change	$ (6,736)	$ (34,729)	$ (4,190)	$ (21,346)	

Case Nos. 2025-00113 and 2025-00114
Attachment to Filing Requirement
Tab 16 - 807 KAR 5:001 Section 16(7)(c) Item I

Metts

Material Base Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	125,982	174,778	199,101	243,796	743,657
2025 BP	130,085	209,453	203,237	264,691	807,466
Lower/(Higher) than '24 BP	**(4,103)**	**(34,675)**	**(4,136)**	**(20,895)**	**(63,809)**
Primary Changes by Year:					
Coal Outage	10,598	(26,832)	12,086	(13,299)	(17,447)
NGCC Outage	992	3,358	27	(4,065)	312
CT Outage	(26)	29	102	6,502	6,607
Coal Reliability	(10,661)	(3,462)	(9,823)	(1,901)	(25,847)
NGCC Reliability	(775)	(804)	(1,237)	(2,232)	(5,048)
CT Reliability	(2,600)	(1,315)	(884)	(2,521)	(7,320)
Hydro Reliability	(230)	(1,200)	(747)	399	(1,778)
Environmental Non-Mech	991	(4,453)	(2,814)	(1,978)	(8,254)
All Other	(2,392)	4	(846)	(1,800)	(5,034)
Total Variances	**(4,103)**	**(34,675)**	**(4,136)**	**(20,895)**	**(63,809)**

Material Mechanism Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	419	435	432	432	1,718
2025 BP	3,053	490	487	883	4,913
Lower/(Higher) than '24 BP	**(2,634)**	**(55)**	**(55)**	**(451)**	**(3,195)**
Primary Changes by Year:					
CCR Rule Well Monitoring	-	(55)	(55)	(55)	(165)
MC4 ESP Field 2 Replacement	(2,634)	-	-	-	(2,634)
MC ELG UF Membrane Replacement	-	-	-	(396)	(396)
Total Variances	**(2,634)**	**(55)**	**(55)**	**(451)**	**(3,195)**

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Non-Outage:					
Labor	$ 97,160	$ 98,971	$ 102,929	$ 106,022	$ 111,360
Supplemental Contractors	26,741	26,818	27,661	28,049	28,913
Plant Maintenance	45,304	48,379	54,926	58,345	59,777
Plant Operations	9,184	10,380	13,372	13,816	13,991
Subtotal Non-Outage	$ 178,390	$ 184,547	$ 198,888	$ 206,232	$ 214,041
Outage:					
Labor	$ 2,206	$ 3,189	$ 2,634	$ 3,591	$ 2,330
Supplemental Contractors	1,132	1,429	1,862	2,527	1,700
Non-Labor	21,662	39,379	41,622	61,468	33,470
Subtotal Outage	$ 25,000	$ 43,996	$ 46,118	$ 67,586	$ 37,500
Total O&M	**$ 203,390**	**$ 228,543**	**$ 245,005**	**$ 273,818**	**$ 251,542**

2025-2029
Annual Cost of Sales Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Non-Mechanism:					
Labor	$ -	$ -	$ -	$ -	$ -
Supplemental Contractors	240	252	252	264	269
Variable Plant O&M	57,513	60,782	60,165	64,273	67,964
All Other Non-labor	834	860	880	910	928
Subtotal Non-Mechanism	$ 58,587	$ 61,893	$ 61,298	$ 65,447	$ 69,161
ECR Mechanism:					
Labor	$ 909	$ 926	$ 969	$ 988	$ 1,018
Supplemental Contractors	4,930	5,084	5,173	5,311	5,450
Variable Plant O&M	4,195	4,363	4,338	4,484	4,630
Beneficial Reuse	(56,566)	(60,760)	(57,770)	(56,894)	(47,488)
All Other Non-Labor	5,419	5,609	5,839	6,025	6,185
Subtotal ECR Mechanism	$ (41,113)	$ (44,779)	$ (41,451)	$ (40,086)	$ (30,205)
Total O&M	**$ 17,474**	**$ 17,115**	**$ 19,847**	**$ 25,360**	**$ 38,956**

*Note: ECR termination

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Mill Creek	171	171	170	170	170
Trimble County	149	149	149	149	149
Cane Run/Ohio Falls	42	42	42	42	42
Ghent	179	179	179	179	179
EW Brown	90	96	96	95	95
Other Generation	3	3	3	3	3
Co-Ops/Interns	16	16	16	16	16
Total	650	656	655	654	654

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Mill Creek	104	104	95	91	91
Trimble County	110	110	110	110	110
Cane Run/Ohio Falls	5	5	5	5	5
Ghent	121	121	121	121	121
EW Brown	43	41	41	41	41
Total	383	381	372	368	368

2025-2029
O&M Supplemental Contractors Non-Outage($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Boiler Systems	$ 2,027	$ 1,581	$ 1,750	$ 1,731	$ 1,798
Buildings and Grounds	$ 5,534	$ 5,453	$ 5,803	$ 5,988	$ 6,215
CCR Disposal	$ 5,080	$ 5,193	$ 5,332	$ 5,358	$ 5,525
Cooling Water Systems	$ 231	$ 236	$ 250	$ 183	$ 190
Environmental	$ 2,944	$ 2,910	$ 2,976	$ 2,969	$ 3,046
Fuel and Ash Handling Equipment	$ 7,255	$ 7,418	$ 7,573	$ 7,731	$ 7,918
Maintenance Other	$ 1,466	$ 1,939	$ 1,817	$ 1,921	$ 1,963
Plant Operations	$ 1,565	$ 1,435	$ 1,488	$ 1,486	$ 1,562
Process Water	$ 2,025	$ 2,078	$ 2,130	$ 2,186	$ 2,236
Turbine/Generator Systems	$ 137	$ 141	$ 149	$ 149	$ 153
Total Supplemental Contractors (100%)	$ 28,263	$ 28,383	$ 29,267	$ 29,702	$ 30,607
Trimble County Partners	$ (1,521)	$ (1,566)	$ (1,606)	$ (1,652)	$ (1,693)
Total Supplemental Contractors (Net)	$ 26,741	$ 26,818	$ 27,661	$ 28,049	$ 28,913

2025-2029
O&M Plant Maintenance Non-Outage ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Boiler Systems	$ 7,382	$ 7,747	$ 7,890	$ 7,921	$ 8,033
Buildings and Grounds	$ 6,826	$ 6,541	$ 6,878	$ 7,185	$ 7,224
Compressed Air Systems	$ 1,073	$ 1,089	$ 1,121	$ 1,175	$ 1,143
Computer/Monitoring/Controls Systems	$ 2,491	$ 2,571	$ 2,558	$ 2,618	$ 2,659
Cooling and Service Water Systems	$ 3,549	$ 3,193	$ 3,163	$ 3,001	$ 3,348
Electrical Systems	$ 833	$ 803	$ 814	$ 827	$ 893
Flue Gas Desulfurization (FGD)	$ 3,208	$ 3,486	$ 3,470	$ 3,523	$ 3,751
Fuel and Ash Handling Equipment	$ 4,464	$ 5,748	$ 5,192	$ 5,213	$ 5,555
Inspections	$ 65	$ 27	$ 27	$ 28	$ 28
Landfill and CCRT	$ 4,868	$ 4,841	$ 4,790	$ 4,868	$ 4,793
Limestone Systems	$ 2,031	$ 2,688	$ 2,546	$ 2,381	$ 2,499
NGCC (New)	$ -	$ -	$ 1,513	$ 3,117	$ 3,210
Obsolete Inventory	$ 466	$ 544	$ 588	$ 530	$ 526
Other Maintenance	$ 2,348	$ 2,317	$ 2,328	$ 2,515	$ 2,480
Precipitator	$ 138	$ 140	$ 136	$ 137	$ 140
Process Water Systems	$ 794	$ 826	$ 957	$ 973	$ 1,000
Pulse Jet Fabric Filter (PJFF) Systems	$ 576	$ 800	$ 709	$ 822	$ 834
Selective Catalytic Reduction (SCR) Systems	$ 833	$ 735	$ 736	$ 844	$ 847
SO3 Mitigation Systems	$ 289	$ 290	$ 267	$ 268	$ 270
Solar and BESS	$ 107	$ 1,001	$ 6,210	$ 7,141	$ 7,284
Tools and Consumables	$ 1,988	$ 2,009	$ 2,103	$ 2,148	$ 2,191
Turbine/Generator Systems	$ 3,684	$ 3,758	$ 3,765	$ 3,999	$ 4,016
Total Plant Maintenance (100%)	$ 48,014	$ 51,155	$ 57,761	$ 61,236	$ 62,723
Trimble County Partners	$ (2,710)	$ (2,776)	$ (2,835)	$ (2,891)	$ (2,946)
Total Plant Maintenance (Net)	$ 45,304	$ 48,379	$ 54,926	$ 58,345	$ 59,777

2025-2029
O&M Plant Operations Non-Outage ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Administrative and General Supplies	$ 1,300	$ 1,741	$ 1,792	$ 1,776	$ 1,803
Chemicals/Gases/Diesel	$ 104	$ 105	$ 105	$ 107	$ 107
Combustion Turbine Facilities	$ 688	$ 628	$ 709	$ 741	$ 744
Environmental	$ 66	$ 282	$ 150	$ 149	$ 134
Fuel Handling Equipment	$ 2,026	$ 2,079	$ 2,119	$ 2,184	$ 2,222
Health and Safety	$ 1,593	$ 1,609	$ 1,631	$ 1,652	$ 1,669
HydroElectric Facilities	$ 888	$ 841	$ 939	$ 939	$ 939
Landfill and CCRT	$ -	$ -	$ -	$ -	$ -
NGCC (New)	$ -	$ -	$ 288	$ 593	$ 611
OT IT Security	$ -	$ -	$ -	$ -	$ -
Other Operations	$ 4,143	$ 4,953	$ 5,082	$ 5,145	$ 5,209
Refined Coal	$ -	$ -	$ -	$ -	$ -
Tools and Consumables	$ 640	$ 694	$ 631	$ 642	$ 652
Training and Development	$ 134	$ 150	$ 153	$ 155	$ 156
Water and Water Treatment	$ 1,217	$ 1,306	$ 1,343	$ 1,368	$ 1,391
Management Challenge	$ (2,222)	$ (2,557)	$ -	$ -	$ -
Total Plant Operations (100%)	$ 10,576	$ 11,830	$ 14,943	$ 15,449	$ 15,637
Trimble County Partners	$ (1,392)	$ (1,450)	$ (1,571)	$ (1,633)	$ (1,646)
Total Plant Operations (Net)	$ 9,184	$ 10,380	$ 13,372	$ 13,816	$ 13,991

2025-2029
O&M Outage Expense ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Outage Supplemental Contractors:					
Coal Fired Units	$ 1,132	$ 1,407	$ 1,849	$ 2,306	$ 1,547
Combustion Turbines	$ -	$ -	$ -	$ -	$ -
NGCC's	$ -	$ 22	$ 13	$ 221	$ 153
Subtotal Outage Supplemental Contractors (Net)	$ 1,132	$ 1,429	$ 1,862	$ 2,527	$ 1,700
Outage Non-Labor:					
Coal Fired Units	$ 21,090	$ 32,602	$ 39,745	$ 42,232	$ 30,698
Combustion Turbines	$ 571	$ 827	$ 779	$ 823	$ 742
NGCC's	$ -	$ 5,950	$ 1,098	$ 18,413	$ 2,030
Subtotal Outage Non-Labor (Net)	$ 21,662	$ 39,379	$ 41,622	$ 61,468	$ 33,470
Total Outage Supplemental Contractor & Non-Labor (Net)	**$ 22,794**	**$ 40,808**	**$ 43,484**	**$ 63,995**	**$ 35,170**

2025-2029
Variable Plant O&M Expense ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Scrubber Reactant Ex	$ 22,890	$ 23,901	$ 22,346	$ 22,913	$ 24,139
Sorbent Reactant	$ 15,677	$ 17,434	$ 17,039	$ 17,873	$ 18,882
Nox Reduction Reagent	$ 7,965	$ 8,666	$ 8,516	$ 9,137	$ 9,710
Liquid Injection Reagent	$ 8,725	$ 8,793	$ 9,201	$ 10,037	$ 10,765
Process Water Chemicals	$ 1,732	$ 1,823	$ 1,727	$ 1,781	$ 1,925
Activated Carbon	$ 933	$ 978	$ 566	$ 614	$ 599
Water Treatment Chemicals	$ 4,160	$ 4,270	$ 5,922	$ 7,684	$ 7,896
Hydrogen / Gases	$ 421	$ 426	$ 430	$ 438	$ 444
Total Variable Plant O&M Expenses (100%)	$ 62,503	$ 66,291	$ 65,747	$ 70,477	$ 74,361
Trimble County Partners	$ (4,989)	$ (5,509)	$ (5,581)	$ (6,204)	$ (6,397)
Total Variable Plant O&M Expenses (Net)	$ 57,513	$ 60,782	$ 60,165	$ 64,273	$ 67,964

2025-2029
Mechanism O&M Expense ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 1,213	$ 1,235	$ 1,294	$ 1,319	$ 1,362
Supplemental Contractors	$ 5,801	$ 5,978	$ 6,090	$ 6,252	$ 6,411
ELG Chemicals	$ 4,647	$ 4,834	$ 4,830	$ 4,988	$ 5,146
ELG Maintenance	$ 3,007	$ 3,126	$ 3,282	$ 3,387	$ 3,495
Landfill Maintenance/Operations	$ 3,666	$ 3,776	$ 3,889	$ 4,006	$ 4,086
Beneficial Reuse - Ash Sales	$ (8,307)	$ (7,661)	$ (5,984)	$ (5,175)	$ (5,470)
Beneficial Reuse - Gypsum Sales	$ (52,090)	$ (57,322)	$ (56,017)	$ (55,956)	$ (42,174)
Beneficial Reuse Equipment Maintenance	$ 422	$ 434	$ 446	$ 460	$ 469
Emission Allowances	$ 5	$ 5	$ 5	$ 5	$ 5
Total Mechanism O&M Expense (100%)	$ (41,636)	$ (45,596)	$ (42,165)	$ (40,715)	$ (26,670)
Trimble County Partners	$ 523	$ 818	$ 714	$ 629	$ (3,536)
Total Mechanism O&M Expense (Net)	$ (41,113)	$ (44,779)	$ (41,451)	$ (40,086)	$ (30,205)

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Cost of Sales Annual Expense Reconciliation ($000)

	2025	2026	2027	2028
2025 Business Plan	$ 17,474	$ 17,115	$ 19,847	$ 25,360
2024 Business Plan	$ 37,560	$ 35,880	$ 38,982	$ 41,046
Change	$ 20,086	$ 18,765	$ 19,136	$ 15,685
Drivers:				
ECR Mechanism:				
Labor	$ 214	$ 233	$ 224	$ 240
Supplemental Contractors	$ (244)	$ (252)	$ (270)	$ (275)
Non-Labor:				
Beneficial Reuse	$ 21,923	$ 24,424	$ 27,843	$ 26,844
Landfill Mtc/Ops	$ -	$ -	$ -	$ -
ELG Mtc/Ops/Chemicals	$ (37)	$ (17)	$ 61	$ 39
Non-Mechanism:				
Limestone	$ (18)	$ (727)	$ (1,393)	$ (1,346)
PWS & Water Treatment Chemicals	$ 348	$ 165	$ (1,168)	$ (2,664)
Ammonia	$ (88)	$ (617)	$ (1,200)	$ (1,415)
Activated Carbon & Mercury Control	$ 449	$ (336)	$ (566)	$ (1,027)
Hydrated Lime	$ (2,465)	$ (4,110)	$ (4,394)	$ (4,708)
Other Waste Disposal	$ 3	$ 2	$ (2)	$ (2)
Total Drivers	$ 20,086	$ 18,765	$ 19,136	$ 15,685

Operational Performance

Key Performance Indicators

KPI	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Generation (Twh)[1]	32.54	32.53	30.29	29.18	30.72
EAF (Steam)	87.2%	84.8%	86.1%	83.6%	88.4%
EFOR (Steam)	2.5%	3.2%	3.0%	3.1%	3.0%
Controllable Cost ($M)[2]	$237.2	$262.9	$282.8	$317.3	$308.6
Controllable Cost (per Mwh)[2]	$7.29	$8.08	$9.34	$10.87	$10.05
O&M Cost ($M)[3]	$219.6	$245.6	$262.8	$291.8	$269.5
O&M Cost (per Mwh)[3]	$6.75	$7.55	$8.68	$10.00	$8.77
FERC Cost Per Mwh[4]	$8.11	$7.97	$7.98	$8.48	$8.91

[1] **Steam Generation includes 75% of Trimble County 1 and 2.**

[2] **Controllable Costs include Mech and Non-Mech Utility O&M and Cost of Sales.**

[3] **O&M Cost excludes Utility Mech and Non-Mech Cost of Sales. Generation Engineering is included in O&M Cost.**

[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)**

All Other LOB and Shared Services
LG&E and KU Utilities
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2025-2029
Total Annual O&M Expenses ($000)

Line of Business	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
VP and COO (LKE)	$ 498	$ 512	$ 528	$ 544	$ 562
Business Operations Reporting	285	293	305	314	296
Real Estate and Right of Way	985	1,140	1,181	1,207	1,237
Energy Supply and Analysis	9,003	9,747	10,093	10,375	10,671
Communications and Corporate Responsibility	8,527	8,632	8,749	8,873	9,005
State Regulation and Rates	2,919	2,908	3,314	2,671	3,052
Services Integration	2,078	2,055	2,100	2,136	2,178
Supply Chain	8,554	9,052	9,758	9,925	10,203
Research and Development	3,711	3,274	3,298	3,239	3,266
VP & Chief Security Officer	8,701	9,523	9,906	10,244	10,459
EVP and COO	571	533	547	558	572
Director Environmental Compliance	7,157	7,979	8,384	8,952	9,001
Safety and Technical Training	13,996	13,809	14,189	14,499	14,661
SVP and Chief Utility Operation Officer	449	442	504	509	509
Manager Compliance	880	1,003	932	959	1,092
EVP and Chief Tech and Innovation Officer	308	329	344	356	370
President and Business Economic Development	2,793	2,886	3,063	3,043	3,121
Chief Financial Officer	27,741	28,964	30,145	31,150	32,264
Human Resources	8,965	9,799	9,939	10,246	10,560
EVP and CLP and Corporate Secretary	19,452	20,206	20,301	21,069	21,134
Total O&M	**$ 127,573**	**$ 133,089**	**$ 137,581**	**$ 140,869**	**$ 144,212**

2025-2029
PPL Allocations Annual O&M Expenses ($000)

Line of Business	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
VP and COO (LKE)	$ -	$ -	$ -	$ -	$ -
Business Operations Reporting	-	-	-	-	-
Real Estate and Right of Way	-	-	-	-	-
Energy Supply and Analysis	-	-	-	-	-
Communications and Corporate Responsibility	753	787	812	832	855
State Regulation and Rates	-	-	-	-	-
Services Integration	2,078	2,055	2,100	2,136	2,178
Supply Chain	7,654	8,131	8,807	8,929	9,179
Research and Development	3,711	3,274	3,298	3,239	3,266
VP & Chief Security Officer	3,989	4,478	4,620	4,751	4,860
EVP and COO	571	533	547	558	572
Director Environmental Compliance	1,088	1,167	1,240	1,290	1,342
Safety and Technical Training	5,654	5,616	5,794	5,936	6,105
SVP and Chief Utility Operation Officer	-	-	-	-	-
Manager Compliance	-	-	-	-	-
EVP and Chief Tech and Innovation Officer	308	329	344	356	370
President and Business Economic Development	327	345	359	369	381
Chief Financial Officer	16,566	17,664	18,499	19,203	19,923
Human Resources	8,965	9,799	9,939	10,246	10,560
EVP and CLP and Corporate Secretary	19,452	20,206	20,301	21,069	21,134
Total O&M	**$ 71,116**	**$ 74,385**	**$ 76,661**	**$ 78,915**	**$ 80,725**

2025-2029
LKE Annual O&M Expenses ($000)

Line of Business	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
VP and COO (LKE)	$ 498	$ 512	$ 528	$ 544	$ 562
Business Operations Reporting	285	293	305	314	296
Real Estate and Right of Way	985	1,140	1,181	1,207	1,237
Energy Supply and Analysis	9,003	9,747	10,093	10,375	10,671
Communications and Corporate Responsibility	7,774	7,845	7,937	8,041	8,150
State Regulation and Rates	2,919	2,908	3,314	2,671	3,052
Services Integration	-	-	-	-	-
Supply Chain	900	921	951	996	1,024
Research and Development	-	-	-	-	-
VP & Chief Security Officer	4,712	5,045	5,286	5,493	5,598
EVP and COO	-	-	-	-	-
Director Environmental Compliance	6,070	6,813	7,143	7,662	7,659
Safety and Technical Training	8,342	8,193	8,395	8,562	8,556
SVP and Chief Utility Operation Officer	449	442	504	509	509
Manager Compliance	880	1,003	932	959	1,092
EVP and Chief Tech and Innovation Officer	-	-	-	-	-
President and Business Economic Development	2,466	2,541	2,705	2,673	2,741
Chief Financial Officer	11,174	11,299	11,646	11,946	12,341
Human Resources	-	-	-	-	-
EVP and CLP and Corporate Secretary	-	-	-	-	-
Total O&M	**$ 56,457**	**$ 58,703**	**$ 60,920**	**$ 61,953**	**$ 63,487**

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LG&E KU
PPL companies

2025-2029
Annual Cost of Sales Expenses ($000)

Line of Business	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Energy Supply and Analysis	$ 8,498	$ 9,169	$ 10,475	$ 9,866	$ 11,910
Total Cost of Sales	**$ 8,498**	**$ 9,169**	**$ 10,475**	**$ 9,866**	**$ 11,910**

Customer Service
LG&E and KU Utilities
2025 Operating Plan

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Major Assumptions

- The "Customer Experience" will continue to be a significant focus across the Company.
- The plan includes assumptions based on the on-time completion of the AMI implementation by the end of 2025.
- The Company will continue investing in infrastructure such as vehicle electrification that could diversify revenue streams.
- The Company will continue investing in technologies to improve customer experience and enhance the digital experience, as well as initiate strategies to increase the adoption of paperless bills.
- The plan assumes savings associated with process improvements and technology initiatives. Risk in achieving O&M targets if savings are lower than anticipated.
- Customer expectations regarding levels of service, digital experience and availability of information will continue to increase.

Major Assumptions

- DSM cost of sales and capital reflected in the plan are based on the DSM filing approved in November 2023 by the KPSC.
- Contractor staffing for meter reading, meter deployment and contact center employees will be available at current market pricing. Potential challenges may arise in maintaining contractor staffing levels.
- Plan to meet AMI contractor staffing reduction commitments for meter reading – will utilize company Field Operations techs to complete manual meter read requirements.
- Contractor Field Operations hourly rates are expected to increase due to short-term staffing challenges.
- Challenges will continue in maintaining skilled contact center staffing levels.
- Labor and supply chain risks are manageable.

Savings/Efficiencies/Cost Reduction Measures

- Continue meter reading and field services savings associated with the AMI deployment post completion of the project.
- Continue savings in 2025 and beyond for bill print and postage reductions. Existing challenges include lower than projected paperless billing enrollment and rising postage expenses.
- Realize contact center and other O&M savings through IT reinvention initiatives.

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
AMI Projects	**$ 59,225**	**$ 118**	**$ 122**	**$ 125**	**$ 129**
IT Systems	$ 169	$ -	$ -	$ -	$ -
Meters	$ 40,597	$ -	$ -	$ -	$ -
Meter Deployment	$ 5,896	$ -	$ -	$ -	$ -
Customer Engagement	$ 1,195	$ -	$ -	$ -	$ -
Meter-to-Cash	$ 1,000	$ -	$ -	$ -	$ -
Remote Service Switch	$ 1,306	$ -	$ -	$ -	$ -
DO Integration	$ 6,914	$ -	$ -	$ -	$ -
Network Communication	$ 2,107	$ -	$ -	$ -	$ -
AOC Renovations	$ 41	$ -	$ -	$ -	$ -
Ongoing Network Equipment	$ -	$ 118	$ 122	$ 125	$ 129
Electric Vehicle Charging Stations	**$ 100**	**$ 100**	**$ 100**	**$ 100**	**$ 100**
Meter Purchases & Installation	**$ 718**	**$ 925**	**$ 2,904**	**$ 2,941**	**$ 2,958**
DSM Projects	**$ 1,833**	**$ 312**	**$ 412**	**$ 426**	**$ 432**
All Other	**$ 632**	**$ 452**	**$ 588**	**$ 621**	**$ 632**
Total Capital	**$ 62,508**	**$ 1,908**	**$ 4,126**	**$ 4,214**	**$ 4,251**
2024 Plan	**$ 87,474**	**$ 6,074**	**$ 8,660**	**$ 8,727**	**$ 8,962**
Change	**$ 24,966**	**$ 4,166**	**$ 4,534**	**$ 4,513**	**$ 4,711**

Material Base Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	85,315	5,704	8,255	8,308	107,583
2025 BP	60,675	1,596	3,714	3,788	69,773
Lower/(Higher) than '24 BP	**24,640**	**4,108**	**4,541**	**4,520**	**37,810**
Primary Changes by Year:					
AMI Projects	20,544	1	1	1	20,546
Meter Purchases & Installs [1]	4,163	4,193	4,628	4,608	17,591
Electric Vehicle Charging Stations	(74)	(74)	(74)	(74)	(296)
All Other Base Capital Projects	7	(11)	(13)	(14)	(32)
Total Variances	**24,640**	**4,108**	**4,541**	**4,520**	**37,810**

[1] Primarily due to the transfer of the Gas Meter Shop to Gas Operations.

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Material Mechanism Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	2,158	370	405	419	3,353
2025 BP	1,833	312	412	426	2,983
Lower/(Higher) than '24 BP	**326**	**58**	**(7)**	**(7)**	**370**
Primary Changes by Year:					
DSM Projects	326	58	(7)	(7)	370
Total Variances	**326**	**58**	**(7)**	**(7)**	**370**

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 50,231	$ 52,881	$ 52,618	$ 53,882	$ 55,331
Supplemental Contractors	$ 1,826	$ (305)	$ (976)	$ (2,600)	$ (3,865)
Other Outside Services	$ 3,804	$ 4,341	$ 5,908	$ 5,863	$ 5,762
Materials & Supplies	$ 662	$ 700	$ 765	$ 782	$ 688
Transportation	$ 2,224	$ 2,779	$ 3,413	$ 3,716	$ 4,106
Postage	$ 4,423	$ 4,498	$ 4,858	$ 4,671	$ 4,764
All Other Non-labor	$ 1,842	$ 3,475	$ 4,230	$ 3,820	$ 3,783
Total O&M	**$ 65,011**	**$ 68,370**	**$ 70,816**	**$ 70,134**	**$ 70,569**

2025-2029
Annual Cost of Sales Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 2,046	$ 2,257	$ 2,330	$ 2,399	$ 2,449
Supplemental Contractors	$ 18,654	$ 19,743	$ 20,427	$ 21,553	$ 21,775
All Other Nonlabor	$ 10,812	$ 16,198	$ 23,735	$ 38,863	$ 40,004
Total O&M	**$ 31,513**	**$ 38,198**	**$ 46,491**	**$ 62,815**	**$ 64,228**

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
VP Customer Service	2	2	2	2	2
Customer Revenue	203	180	180	180	180
Customer Service Operations & Support	264	264	264	264	264
Customer Programs	35	37	37	37	37
AMI	20	11	11	11	11
Interns	4	4	4	4	4
Total	528	498	498	498	498

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Customer Revenue	54	28	26	26	26
Customer Service Operations & Support	2	2	2	2	2
Customer Programs	90	91	92	93	94
AMI	-	-	-	-	-
Total	146	121	120	121	122

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Supplemental Contractors					
Billing Integrity	$ 136	$ 156	$ 164	$ 169	$ 174
Meter Assets	373	322	332	335	293
Field Service Operations	837	-	-	-	-
Meter Reading	300	-	-	-	-
IT Reinvention Savings	-	(852)	(1,550)	(3,183)	(4,360)
All Other	180	69	77	78	27
Total	**$ 1,826**	**$ (305)**	**$ (976)**	**$ (2,600)**	**$ (3,865)**
Other Outside Services					
Billing Integrity	$ 1,176	$ 1,278	$ 1,326	$ 1,366	$ 1,407
CS Business Analysis	615	774	844	817	747
Business Services	247	255	348	265	269
Revenue Strategy & Collection	869	1,275	1,404	1,428	1,399
Customer Programs	130	325	325	325	325
Regulatory Programs	188	143	188	188	208
Residential Service Center	327	461	672	672	672
Retail Business Systems, Strategy & Learning	495	779	789	789	731
Gap	(316)	(962)	-	-	-
All Other	74	14	14	14	6
Total	**$ 3,804**	**$ 4,341**	**$ 5,908**	**$ 5,863**	**$ 5,762**

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Materials & Supplies					
Meter Assets	$ 152	$ 152	$ 152	$ 152	$ 152
Field Service Operations	191	250	245	248	234
Meter Reading	78	77	76	70	60
Regulatory Programs	115	76	148	169	133
All Other	125	143	145	144	108
Total	**$ 662**	**$ 700**	**$ 765**	**$ 782**	**$ 688**
Transportation					
Meter Assets	$ 753	$ 997	$ 957	$ 1,065	$1,192
Field Service Operations	1,310	1,520	2,068	2,238	2,432
Meter Reading	144	156	171	187	206
Electric Vehicle Strategy	-	88	198	206	255
All Other	17	18	20	20	21
Total	**$ 2,224**	**$ 2,779**	**$ 3,413**	**$ 3,716**	**$4,106**

2025-2029 O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
All Other					
Meals	$ 320	$ 313	$ 322	$ 323	$ 314
Telecomm	660	606	606	608	598
AMI - Information Technology	1,342	1,272	1,372	1,452	1,472
Mileage	126	145	153	129	123
Travel	120	295	323	319	318
Education & Training	130	161	169	163	154
Residential Service Center	405	382	806	495	495
AMI Transfer to Reg Asset	(1,645)	-	-	-	-
All Other	384	301	480	331	309
Total	**$ 1,842**	**$ 3,475**	**$ 4,230**	**$ 3,820**	**$ 3,783**

2025-2029
Mechanism O&M Expense ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
DSM Programs					
WeCare (homeowners & renters)	8,961	8,971	8,982	8,994	9,005
WeCare (apartment building owners)	1,111	1,267	1,123	1,130	1,136
Appliance Recycling	-	1,671	1,723	1,926	1,778
Online Marketplace	313	510	974	1,097	1,098
Residential Audit Online	1,085	1,265	1,597	1,681	1,636
BYOD	1,679	2,976	4,866	7,611	9,876
Business Rebates	5,177	4,294	3,768	3,883	3,794
Small Business - Audit & DI	618	620	622	725	627
Demand Conservation	3,391	3,024	4,583	12,124	11,017
Business Demand Response	3,863	4,343	5,174	6,033	6,904
Peak Time Rebates	1,995	2,959	5,682	9,922	10,075
Optimized EV Charging	538	676	813	1,123	1,395
Business Midstream Lighting	-	2,906	3,688	3,793	3,081
PDA	2,782	2,716	2,896	2,773	2,806
Total DSM	**$ 31,513**	**$ 38,198**	**$ 46,491**	**$ 62,815**	**$ 64,228**

Cost of Sales Annual Expense Reconciliation ($000)

	2025	2026	2027	2028
2025 Business Plan (pg.10)	$ 31,513	$ 38,198	$ 46,491	$ 62,815
2024 Business Plan	31,459	38,622	46,868	63,196
Change	$ (54)	$ 424	$ 377	$ 381
Drivers:				
Removal of ODP DSM Programs	$ 371	$ 430	$ 383	$ 387
Other	$ (425)	$ (7)	$ (6)	$ (5)
Total Drivers	$ (54)	$ 424	$ 377	$ 381

Operational Performance

Key Performance Indicators

KPI	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Overall Customer Experience [1]	4.00	4.00	4.00	4.00	4.00
LKE Service Order Days to Complete [2]	1.00	1.00	1.00	1.00	1.00

[1] Starting in January 2022, Customer Experience moved from a 10-point to a 5-point scale.

[2] Measures the time between the scheduled date and the completed service order date (excludes credit and adjustment-related service orders).

Electric Distribution
LG&E and KU Utilities
2025 Operating Plan

LG&E KU
PPL companies

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Major Assumptions

- Electric Distribution will continue to provide safe, reliable electric service to our customers.
- New Business investments for electric system expansion and upgrades will continue to be influenced by local economies and job markets. Excluding major projects, plan funding reflects normal escalation per annum from 2024 forecast for the remainder of the plan.
  - Major projects include Shelby, Tucker Station and Campbellsburg substations and Cawood lines
  - Risk exists as more distilleries want to open that are not specifically assumed in the plan
- Investment priorities include DSHARP, Wildfire Mitigation, VVO/CVR, PITP and other aging asset replacements
  - Continued growth in LED conversion projects is a risk; plan assumes only normal escalation
- Electrification of vehicles is not expected to have a major impact in the short term. Majority of impacts is expected at the service transformer level. So far, load modeling at the circuit and substation level have not indicated any significant investments needed to serve the new load.
- Storm budgets for O&M and capital reflect the most recent 5-year average for associated costs (escalated by CPI), excluding significant storms/anomalies.
  - Risk of increased storm costs as reliance on external resources to support restoration efforts increases.

Major Assumptions

- Vegetation continues to be a leading contributor to the frequency and duration of distribution system outages. Funding allocated to mitigate vegetation interference, prioritizing routine cycle based work and simultaneous completion of hazard tree removals with routine work (there are no active invasive species contributing to higher disease rates).
- IT investment
  - New platforms are critical to the targeted O&M reductions.
- Market supply and demand for materials could lead to higher pricing and delivery constraints.
- Tariffs could lead to higher prices for materials

Savings/Efficiencies/Cost Reduction Measures

- Vegetation management savings in 2025 are reflective of pull forward work completed in 2024, primarily on the Transmission system.
- LKE Fleet right sizing initiative was completed in 2023 with identified vehicles being removed from service.
- Reduce future outage runs and offset OPEX costs with installation of Vacu-fuses on transformer outages if devices are delivered in 2024.
- AMI capabilities to check status of customer meters will reduce truck rolls when not needed.
- Additional savings as asset replacement vs repair implementation continues to mature across operations.

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
CONNECT NEW CUSTOMER	127,451	122,987	134,840	137,796	138,351
ENHANCE THE NETWORK	90,477	208,505	187,763	176,951	170,133
MAINTAIN THE NETWORK	95,675	111,867	120,468	121,272	121,035
REPAIR THE NETWORK	23,783	24,433	25,108	25,782	26,012
MISCELLANEOUS	4,738	4,332	4,237	4,248	5,522
Total Capital	342,124	472,123	472,415	466,050	461,053
2024 Plan	326,418	402,122	357,407	366,056	
Change	(15,706)	(70,001)	(115,008)	(99,994)	

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Metts

Material Base Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	326,418	402,122	357,407	366,056	1,452,003
2025 BP	342,124	472,123	472,415	466,050	1,752,712
Lower/(Higher) than '24 BP	**(15,706)**	**(70,001)**	**(115,008)**	**(99,994)**	**(300,709)**
Primary Changes by Year:					
New Business - Blankets	(5,027)	(1,959)	47	(1,949)	**(8,887)**
New Business - Other Major Projects	(18,657)	(633)	(12,128)	(18,995)	**(50,413)**
Transformer Purchases	(18,195)	(23,629)	(23,270)	(22,277)	**(87,370)**
N1DT	2,691	3,027	(4,000)	-	**1,718**
System Enhancements to Meet Demand	(14,189)	(3,141)	1,900	6,720	**(8,710)**
Enhancements for Reliability Improvements	(1,272)	15,008	(297)	8,646	**22,085**
DSHARP	(9,989)	(84,475)	(98,203)	(95,826)	**(288,493)**
Wildfire Mitigation	(10,000)	(16,000)	(16,000)	(16,000)	**(58,000)**
Voltage Controller Upgrades	-	(4,000)	(2,000)	(2,000)	**(8,000)**
Repair/Replace Aging Infrastructure - Substation Maintenance	(20,364)	(25,240)	(33,422)	(31,518)	**(110,543)**
Repair/Replace Aging Infrastructure	(7,125)	7,878	(10,000)	(4,877)	**(14,124)**
Asset Prioritization Programs	97,941	67,651	87,430	79,656	**332,678**
Repair/Replace Defective Equipment	(11,148)	(3,204)	(3,534)	(2,076)	**(19,962)**
All Others	(372)	(1,284)	(1,533)	500	**(2,689)**
Total Variances	**(15,706)**	**(70,001)**	**(115,008)**	**(99,994)**	**(300,709)**

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 25,748	$ 25,844	$ 26,704	$ 27,047	$ 27,464
Non Labor					
Vegetation Management[1]	23,305	28,686	29,135	29,054	28,977
Storms[2]	7,579	9,116	9,456	9,587	9,723
VP and Transportation	(716)	(160)	1,245	1,289	1,611
LG&E Dist Ops	5,382	5,112	5,597	5,388	5,276
KU Dist Ops	8,597	8,898	9,286	9,218	9,268
Dist Systems, Ops & Planning	1,481	1,677	1,688	1,739	1,746
Investment Strategy & Reliability	259	1,228	1,277	1,243	1,215
Total O&M	**$ 71,635**	**$ 80,401**	**$ 84,388**	**$ 84,565**	**$ 85,280**
Supplemental Contractors (included above)	36,694	43,164	44,575	44,199	44,313

[1]Total Vegetation Management including labor is $25.6M in 2025, $31M in 2026, and $31.6M in 2027, 2028, and 2029.

[2]Total Storm Restoration including labor is $11.5M in 2025, $12.7M in 2026, $13M in 2027, $13.3M in 2028, and $13.6M in 2029.

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
EDO VP	3	3	3	3	3
Transportation	3	3	3	3	3
LG&E Distribution Operations	178	178	178	178	178
KU Distribution Operations	307	307	307	307	306
Vegetation Management	15	15	15	15	16
Distribution System Operations	78	78	78	78	78
Investment Strategy & Reliability	18	18	18	18	18
Interns	8	8	8	8	8
Total	610	610	610	610	610

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
LG&E Distribution Operations	363	503	601	580	580
KU Distribution Operations	278	336	336	336	336
Vegetation Management	365	394	394	394	394
Distribution System Operations	27	27	27	27	27
Investment Strategy & Reliability	18	18	18	18	18
Transportation	23	23	23	23	23
Total	1,074	1,301	1,399	1,378	1,378

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Vegetation Management:					
Routine LGE	5,291	5,350	5,396	5,300	5,300
Routine KU	9,766	10,083	10,292	10,102	10,104
Subtotal Routine	$ 15,057	$ 15,433	$ 15,688	$ 15,402	$ 15,404
Hazard LGE	1,847	1,849	1,597	1,600	1,591
Hazard KU	2,335	2,677	2,929	2,918	2,881
Subtotal Hazard	$ 4,182	$ 4,526	$ 4,526	$ 4,518	$ 4,472
Total Distribution Veg Mgmt	$ 19,239	$ 19,959	$ 20,214	$ 19,920	$ 19,876
Right of Way LGE	653	1,277	1,310	1,319	1,320
Right of Way KU	3,413	7,450	7,611	7,815	7,781
Total Transmission Veg Mgmt	$ 4,066	$ 8,727	$ 8,921	$ 9,134	$ 9,101
Vegetation Management Total	**$ 23,305**	**$ 28,686**	**$ 29,135**	**$ 29,054**	**$ 28,977**

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Storm Restoration - 5 yr. avg	**$ 7,579**	**$ 9,116**	**$ 9,456**	**$ 9,587**	**$ 9,723**

	Total Expense			CPI	CPI Adjusted Amount				
	LGE	KU	Total	Index	LG&E	KU	Total		
Normalized Storm Costs:									
2023	11,697	7,647	19,344	1.0000	11,697	7,647	19,344		
2022	6,283	6,518	12,802	1.0413	6,543	6,788	13,331		
2021	3,411	6,588	9,999	1.1245	3,836	7,408	11,244		
2020	2,859	2,317	5,176	1.1771	3,366	2,727	6,093		
2019	5,438	2,130	7,569	1.1919	6,482	2,539	9,021		
Total	29,688	25,200	54,890		31,924	27,109	59,033		
5 Year Average	**5,938**	**5,040**	**10,978**		**6,385**	**5,422**	**11,807**		
5 Year Average - CPI Adjusted								Labor	Non Labor
2025				1.0479	**6,690**	**5,681**	**12,371**		
2026				1.0727	**6,849**	**5,816**	**12,665**	3,548	9,116
2027				1.0985	**7,014**	**5,956**	**12,970**	3,514	9,456
2028				1.1232	**7,171**	**6,090**	**13,261**	3,675	9,587
2029				1.1480	**7,329**	**6,224**	**13,553**	3,830	9,723

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
VP					
Liability Claims	607	625	643	642	642
Transportation - EV Strategy	-	222	417	467	788
Management Challenge	(943)	(1,159)	-	-	-
Other	(380)	152	185	180	180
VP Total	**$ (716)**	**$ (160)**	**$ 1,245**	**$ 1,289**	**$ 1,611**
LG&E Distribution Operations					
Administrative	479	488	498	465	460
Building, Tools & Equipment	290	300	300	300	300
Inspections	346	346	346	346	346
Metering	209	209	209	209	209
Network Vaults	469	368	468	468	468
Repair Defective Equipment	1,615	1,609	1,595	1,595	1,584
Repair Street Lighting	200	200	200	200	200
Safety/Training/Uniforms	581	621	620	627	631
Transformer Services	44	44	50	50	50
Trouble Work	1,049	813	1,220	1,057	958
Other	100	115	91	71	70
LG&E Distribution Total	**$ 5,382**	**$ 5,112**	**$ 5,597**	**$ 5,388**	**$ 5,276**

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
KU Distribution Operations					
Administrative	995	1,028	1,049	938	909
Aerial Patrol	990	1,035	1,061	1,084	1,080
Building, Tools & Equipment	572	578	627	610	601
Inspections	374	421	421	426	418
Line Locating	1,395	1,390	1,444	1,422	1,395
Repair Defective Equipment	524	542	566	584	603
Repair Street Lighting	161	173	181	183	188
Safety/Training/Uniforms	866	911	961	979	985
Trouble Work	2,512	2,605	2,793	2,864	2,951
Other	209	215	183	129	137
KU Distribution Operations Total	**$ 8,597**	**$ 8,898**	**$ 9,286**	**$ 9,219**	**$ 9,268**
Distribution Systems, Operations & Planning					
System Restoration & Dispatch	830	1,021	1,013	1,098	1,102
Asset Information	202	174	241	246	252
Dist System Administration	437	436	427	419	416
Other	13	46	6	(24)	(24)
Dist Systems, Ops & Planning Total	**$ 1,481**	**$ 1,677**	**$ 1,688**	**$ 1,739**	**$ 1,746**
Investment Strategy & Reliability					
Electrical Engineering & Planning	56	117	106	94	68
Pole Inspection & Treatment Program	-	896	945	945	945
Regulatory Compliance & Special Contracts	163	162	179	171	162
Other	40	53	47	33	40
Investment Strategy & Reliability Total	**$ 259**	**$ 1,228**	**$ 1,277**	**$ 1,243**	**$ 1,215**

Operational Performance

Key Performance Indicators

KPI	2025 Plan
SAIFI	0.781
SAIDI	79.87
Residential New Business Cycle Time (Business Days) [1]	3.00
Repair Street Lights (Business Days) [2]	2.00
Electric Trouble Arrival Response Time (Minutes) [3]	45.00
Estimated Restoration Time (ERT) Accuracy [4]	96.0%

1) Measures the time between the approved inspection and the connection to the customer.
2) Measures the duration from once the call is received to when we are onsite
3) Measures the time frame between the first call and arrival time for emergency
4) Measures the percentage that service is restored on or before the ERT.

Project Engineering and Facilities
LG&E and KU Utilities
2025 Operating Plan

LG&E KU
PPL companies

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Major Assumptions

- Plan assumes CPCN (ECR for GH2 SCR) approval in November 2025
- 2025 ECR (ELG/ZLD) filing approval TBD

Savings/Efficiencies/Cost Reduction Measures

- Exit costs for the LG&E Center are considered a Special Item in this plan
- Facilities Services has no winter weather clearing activities included (OPEX)
- OPEX reductions in employee training and travel

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
2031 NGCC (Mill Creek 6)*	$ 575	$ 26,600	$ 81,918	$ 311,200	$ 344,664
Brown 12*	$ 26,150	$ 81,148	$ 311,200	$ 357,014	$ 312,297
2028 BESS*	$ 1,784	$ 205,138	$ 579,627	$ 101,466	$ -
Mill Creek 5*	$ -	$ -	$ -	$ -	$ -
Brown BESS*	$ 146,555	$ 109,455	$ 12,600	$ -	$ -
Marion Solar*	$ 150	$ 150	$ 252,095	$ -	$ -
Mercer Co Solar*	$ 52,712	$ 175,427	$ 5,060	$ -	$ -
Ghent REV ELG	$ 2,400	$ 32,500	$ 48,400	$ 48,400	$ 32,500
Trimble Co Stack Replacmnt	$ 43,275	$ 59,587	$ 54,595	$ -	$ -
Ghent 2 SCR	$ 4,625	$ 37,100	$ 92,850	$ 17,827	$ -
Trimble Co REV ELG (NET)	$ 2,400	$ 21,900	$ 32,500	$ 32,500	$ 21,900
Brown Units 1 & 2 Demo	$ 18,733	$ 8,800	$ -	$ -	$ -
Bluegrass Service Center	$ 20,104	$ 1,419	$ -	$ -	$ -
All Other	$ 477,815	$ 291,608	$ 101,112	$ 30,709	$ 24,927
Total Capital	**$ 797,277**	**$ 1,050,831**	**$ 1,571,957**	**$ 899,116**	**$ 736,287**
2024 Plan	**$ 749,457**	**$ 564,649**	**$ 630,373**	**$ 358,008**	
Change	**$ (47,820)**	**$ (486,182)**	**$ (941,584)**	**$ (541,108)**	

*Does not include AFUDC

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Material Base Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	$ 82,872	$ 49,413	$ 25,919	$ 18,493	$ 176,697
2025 BP	$ 114,709	$ 106,314	$ 83,890	$ 30,709	$ 335,622
Lower/(Higher) than '24 BP	**$ (31,837)**	**$ (56,901)**	**$ (57,970)**	**$ (12,216)**	**$ (158,925)**
Primary Changes by Year:					
TC Stack Replacement (NET)	$ (12,255)	$ (38,116)	$ (52,057)	$ -	$ (102,427)
Brown Units 1 & 2 Demolition	$ (9,006)	$ (8,800)	$ -	$ -	$ (17,806)
Bluegrass Service Center	$ (3,304)	$ 2	$ -	$ -	$ (3,301)
Carrollton Relocation	$ (2,546)	$ -	$ -	$ -	$ (2,546)
CR7 Carbon Capture (in Transmission 2024)	$ (879)	$ (745)	$ (4,420)	$ (6,209)	$ (12,253)
Simpsonville TCC CRAC Replacement	$ -	$ -	$ -	$ (2,500)	$ (2,500)
Mill Creek AQCS Demolition	$ -	$ -	$ (500)	$ (5,500)	$ (6,000)
All Other	$ (3,848)	$ (9,243)	$ (993)	$ 1,993	$ (12,091)
Total Variances	**$ (31,837)**	**$ (56,901)**	**$ (57,970)**	**$ (12,216)**	**$ (158,925)**

Material Mechanism Capital Variances by Year ($000)

	2025	2026	2027	2028	Total 25-28
2024 BP	$ 19,856	$ -	$ -	$ -	$ 19,856
2025 BP	$ 75,185	$ 91,500	$ 173,750	$ 98,727	$ 439,162
Lower/(Higher) than '24 BP	**$ (55,330)**	**$ (91,500)**	**$ (173,750)**	**$ (98,727)**	**$ (419,307)**
Primary Changes by Year:					
Ghent 2 SCR	$ (4,625)	$ (37,100)	$ (92,850)	$ (17,827)	$ (152,402)
Ghent REV ELG	$ (2,400)	$ (32,500)	$ (48,400)	$ (48,400)	$ (131,700)
Trimble Co REV ELG (NET)	$ (2,400)	$ (21,900)	$ (32,500)	$ (32,500)	$ (89,300)
Trimble Co GSP Closure (NET)	$ (2,559)	$ -	$ -	$ -	$ (2,559)
Trimble Co BAP Closure (NET)	$ (860)	$ -	$ -	$ -	$ (860)
Ghent ELG*	$ (9,145)	$ -	$ -	$ -	$ (9,145)
Trimble Co ELG (NET)*	$ (19,694)	$ -	$ -	$ -	$ (19,694)
All Others	$ (13,647)	$ -	$ -	$ -	$ (13,647)
					$ -
Total Variances	**$ (55,330)**	**$ (91,500)**	**$ (173,750)**	**$ (98,727)**	**$ (419,307)**

***Projects included in the 2020 ECR Plan**

New ECR filing expected in XXXXX

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2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 2,171	$ 2,229	$ 2,274	$ 2,343	$ 2,409
Supplemental Contractors	$ 2,927	$ 3,195	$ 3,532	$ 3,532	$ 3,532
Non-Labor:					
Outside Services	$ 5,441	$ 5,006	$ 5,706	$ 5,648	$ 5,582
All Other Non-Labor	$ 1,992	$ 1,987	$ 2,371	$ 2,347	$ 2,347
Subtotal Non-Labor	**$ 7,433**	**$ 6,993**	**$ 8,077**	**$ 7,995**	**$ 7,929**
Total O&M	**$12,531**	**$12,417**	**$13,883**	**$13,870**	**$13,870**

*Supplemental Contractors (SC) are Facilities Services and Projects. Project Engineering SC are charged to Capital.

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Sr Director/Commercial	10	10	10	10	10
Major Project Construction	31	31	31	31	31
Major Project Development	1	1	1	1	1
Facilities Service	16	16	16	16	16
Facilities Projects	6	6	6	6	6
Facilities Support/Planning	-	-	-	-	-
Sub Total	**64**	**64**	**64**	**64**	**64**
Co-Ops*	4	4	4	4	4
Total	**68**	**68**	**68**	**68**	**68**

*Project Engineering Co-Ops are charged entirely to capital projects and vary due to project and season

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Sr Director/Commercial	-	-	-	-	-
Major Project Construction	10	10	10	10	10
Major Project Development	1	1	1	1	1
Facilities Service	1	1	1	1	1
Facilities Projects	-	-	-	-	-
Facilities Support/Planning	-	-	-	-	-
Total	**12**	**12**	**12**	**12**	**12**

Project Engineering Supplemental Contractors are charged to Capital and staffing will be evaluated as New Generation is approved.

Facilities Services has re-evaluated the classification of Supplemental Contractors.

2025-2029
Outside Services ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Facilities Maintenance & Operations	$3,867	$3,953	$4,344	$4,351	$4,358
Material and Equipment	$ 984	$ 998	$1,097	$1,098	$1,100
Other	$ 150	$ 55	$ 265	$ 199	$ 123
SPECIAL ITEM - LGE Center Removal	$ 440	$ -	$ -	$ -	$ -
	$5,441	**$5,006**	**$5,706**	**$5,648**	**$5,582**

2025-2029
O&M Non Labor Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Purchased Material and Supplies	$ 462	$ 486	$ 819	$ 794	$ 794
Training and Travel	$ 147	$ 143	$ 144	$ 144	$ 144
Transportation and Parking	$ 293	$ 325	$ 291	$ 291	$ 291
Utilities	$ 348	$ 305	$ 335	$ 335	$ 335
Zycus	$ 69	$ 69	$ 69	$ 69	$ 69
All Other	$ 673	$ 659	$ 713	$ 713	$ 713
	$1,992	**$1,987**	**$2,371**	**$2,347**	**$2,347**

O&M Annual Expense Reconciliation ($000)

	2025	2026	2027	2028
2025 Business Plan	$ 12,531	$ 12,417	$ 13,883	$ 13,870
2024 Business Plan	$ 13,069	$ 12,651	$ 13,993	$ 13,980
Change	$ 538	$ 234	$ 110	$ 110
Drivers:				
Transferred to Special Item	$ 440	$ -	$ -	$ -
Management Challenge	$ 98	$ 234	$ 110	$ 110
Total Drivers	$ 538	$ 234	$ 110	$ 110

Gas Operations
LG&E and KU Utilities
2025 Operating Plan

February 2025

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Plan Highlights

Gas Operations strives to provide safe, reliable, and affordable natural gas to our customers while meeting or exceeding state and federal regulatory requirements.

- Safe, reliable delivery of natural gas remains primary goal.
- Bullitt County pipeline constructed and planned to be in operation by YE 2025, final restoration to be completed in 2026.
- In-line inspection work included to meet assessment requirements, support published Mega Rule RIN 1 and RIN 2 requirements.
- Proactive infrastructure replacement and reliability projects included in Business Plan.
- Regulatory compliance programs and activities remain sufficiently funded.
- Gas Operations continues Pipeline Safety Management System (PSMS) implementation.

Plan Highlights

Regulatory Programs

— TSA Cyber Security Directives

— Control Room Management

— Transmission Maximum Allowable Operating Pressure (MAOP) Revalidation

— Integrity Assessments – Transmission and Storage

— Integrity Management Programs – Transmission, Distribution, and Storage

— Gas Leak and Damage Responses

— Legacy Mandated Compliance Programs

- Leak Survey
- Damage Prevention and Public Awareness
- Corrosion Control
- Operator Qualification Program
- Regulator Facility Inspections
- Curb/Service Valve Inspections
- Main Line Valve Inspections

Major Assumptions

- Current leak survey, and repair work (O&M and capital) will be recovered starting in 2026 through the GLT along with incremental costs associated with complying with the LDAR rule.
- The Bullitt County Pipeline project construction will occur in 2025.
- Significant support for Public Work Relocation project continues at least through 2026.
- MAOP reverification work continue during plan.
- OT / IT Cyber security funding is assumed to be sufficient to cover regulatory mandates (TSA Security Directives).
- No mandated requirements related to physical security are assumed in the plan.
- The forecasted Design Day is essentially flat throughout the plan period.

Savings/Efficiencies/Cost Reduction Measures

- Reduce utilization of contractors on non-emergency orders (turn on work).
- Did not backfill a Manager position as part of reorganization.
- Fewer storage wells as a result of completing Doe Run field closure reduced well assessment fee.
- Employees now mowing at compressor station facilities reducing cost from using a contract company.

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Gas Line Tracker	$ 16,695	$ 20,671	$ 18,292	$ 18,808	$ 61,659
Base (Non-Tracker)					
New Business	4,416	4,957	7,789	8,003	8,248
Enhance the Network	116,066	34,523	50,570	43,932	85,691
Maintain the Network	39,588	45,552	40,192	48,500	25,047
Repair the Network	1,334	355	359	415	424
All Other	5,577	6,581	6,628	6,539	6,576
Subtotal Base	**166,981**	**91,968**	**105,538**	**107,389**	**125,987**
Total Capital	**$ 183,676**	**$ 112,639**	**$ 123,830**	**$ 126,197**	**$ 187,646**
2024 Plan	**$ 139,890**	**$ 109,412**	**$ 121,268**	**$ 120,001**	
Change	**$ (43,786)**	**$ (3,227)**	**$ (2,562)**	**$ (6,196)**	

Material Base Capital Variances by Year ($000)

	2024	2025	2026	2027	2028	Total 24-28
2024 BP	$ 70,338	$ 139,890	$ 109,412	$ 121,268	$ 120,001	$ 560,909
2025 BP Proposed	74,997	183,676	112,639	123,830	126,197	621,339
Lower/(Higher) than '24 BP	**$ (4,659)**	**$ (43,786)**	**$ (3,227)**	**$ (2,562)**	**$ (6,196)**	**$ (60,430)**
Primary Changes by Year:						
New Business	$ 1,888	$ 2,573	$ 2,239	$ (378)	$ (370)	$ 5,952
Enhance the Network	(10,517)	(38,851)	2,515	(5,191)	6,950	(45,093)
Maintain the Network	3,154	(4,590)	(826)	7,329	(8,566)	(3,499)
Repair the Network	330	8	1,029	1,066	1,282	3,714
All Other	486	(2,926)	(8,184)	(5,387)	(5,492)	(21,504)
Total Variances	**$ (4,659)**	**$ (43,786)**	**$ (3,227)**	**$ (2,562)**	**$ (6,196)**	**$ (60,430)**

Material Mechanism Capital Variances by Year ($000)

	2024	2025	2026	2027	2028	Total 24-28
2024 BP	$ 21,685	$ 12,855	$ 13,226	$ 13,606	$ 14,122	$ 75,494
2025 BP	20,510	16,695	20,671	18,292	18,808	94,975
Lower/(Higher) than '24 BP	**$ 1,175**	**$ (3,840)**	**$ (7,445)**	**$ (4,685)**	**$ (4,687)**	**$ (19,481)**
Primary Changes by Year:						
New Business	$ (246)	$ (875)	$ (658)	$ (683)	$ (715)	$ (3,177)
Enhance the Network	-	-	(98)	(466)	(368)	(932)
Maintain the Network	1,421	(2,965)	(3,357)	(96)	(98)	(5,094)
Repair the Network	-	-	(3,332)	(3,440)	(3,506)	(10,278)
Total Variances	**$ 1,175**	**$ (3,840)**	**$ (7,445)**	**$ (4,685)**	**$ (4,687)**	**$ (19,481)**

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 31,976	$ 33,486	$ 35,046	$ 36,128	$ 37,456
In-Line Inspections	263	3,890	9,795	10,083	7,640
Line Locating	8,846	9,002	9,190	9,192	9,376
Gas Ops & Construction	3,883	3,972	4,152	4,233	4,233
Gas Control	1,260	1,258	1,291	1,321	1,348
Compressor Stations	3,424	3,453	3,529	3,608	3,680
Corrosion Control	1,723	1,819	2,123	2,190	2,234
Regulatory Services	3,949	2,582	2,635	2,643	2,696
Integrity & Compliance	959	1,099	1,113	1,145	1,168
Other	564	482	1,142	1,164	1,186
Total O&M	**$ 56,847**	**$ 61,043**	**$ 70,015**	**$ 71,709**	**$ 71,017**

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Gas Operations	93	95	95	95	95
Gas Control	52	54	54	54	54
Muldraugh Operations	30	30	30	30	30
Gas Reg Serv. & Corrosion Control	28	29	29	29	29
Gas Construction	23	23	23	23	23
Magnolia Operations	21	23	23	23	23
Pipeline Safety Mgmt. Systems	7	9	12	12	12
Gas Supply	7	7	7	7	7
Operator Qualifications Program	4	4	4	4	4
Senior Managers	3	3	3	3	3
Total	**268**	**277**	**280**	**280**	**280**

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Magnolia Gas Storage Operations	-	-	-	-	-
Muldraugh Gas Storage Operations	9	9	9	9	9
Gas T&D Integrity & Compliance	10	10	10	10	10
Gas Control	1	1	1	1	1
Gas Regulatory & Damage Prevention	119	119	119	119	119
Corrosion Control & Public Awareness	3	3	3	3	3
Gas Construction	85	85	85	85	85
Gas Dist-Construction & Maint	23	23	23	23	23
Gas Dist-Contract Construction	26	26	26	26	26
Gas Supply	1	-	-	-	-
Operator Qualification Program	-	-	-	-	-
Pipeline Safety Mgmt System	-	-	-	-	-
Gas Meter Shop	11	11	11	11	11
Total	288	287	287	287	287

2025-2029 O&M Non Labor Inline Inspection Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
BLANPAD	$ -	$ 2	$ 2,466	$ 1,618	$ -
CALVARY	262	-	-	-	-
CENTER20	-	-	-	3,052	300
MAG16	-	2,978	300	-	-
MAG20	-	-	3,033	298	-
MULPEN	-	-	3,086	300	-
PICPEN	-	-	-	-	2,128
WKA	-	-	-	-	3,956
WKB	-	-	-	3,879	300
Validation Digs	1	910	910	937	955
Total	$ 263	$ 3,890	$ 9,795	$ 10,083	$ 7,640

2025-2029
O&M Non Labor Line Locating Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Electric Locates	$ 4,057	$ 4,146	$ 4,240	$ 4,240	$ 4,325
Electric Unlocatables	688	688	690	691	705
Gas Locates	3,996	4,063	4,128	4,129	4,212
Gas Unlocatable	104	104	132	132	135
Total	$ 8,846	$ 9,002	$ 9,190	$ 9,192	$ 9,376

2025-2029
O&M Non Labor Gas Operations & Construction Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Contractor Labor & Transportation	$ 2,251	$ 1,830	$ 1,880	$ 1,925	$ 1,963
Material	835	1,124	1,146	1,169	1,192
Communications	80	78	80	81	83
Repair 3rd party Damage	(106)	(108)	(110)	(113)	(115)
Gas Meter Shop	745	956	1,062	1,075	1,011
All Other	78	92	94	96	98
Total	$ 3,883	$ 3,972	$ 4,152	$ 4,233	$ 4,233

2025-2029
O&M Non Labor Gas Control & Compressor Stations Expense Categories ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Gas Control					
Contractor Labor & Transportation	$ 853	$ 880	$ 905	$ 927	$ 946
Material	239	217	221	226	231
Communications	24	24	24	25	25
All Other	145	138	140	143	146
Total	$ 1,260	$ 1,258	$ 1,291	$ 1,321	$ 1,348
Compressor Stations					
Contractor Labor & Transportation	$ 1,723	$ 1,733	$ 1,774	$ 1,818	$ 1,854
Material	1,322	1,333	1,360	1,388	1,416
Utilities	127	130	133	135	138
Training	58	58	59	60	62
Communications	45	48	49	50	51
All Other	149	151	154	157	160
Total	$ 3,424	$ 3,453	$ 3,529	$ 3,608	$ 3,680

2025-2029 O&M Non Labor Regulatory Services Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Stop Box Inspections	$ 1,634	$ 1,682	$ 1,724	$ 1,725	$ 1,759
Public Awareness-Opex	$ 289	$ 289	$ 290	$ 291	$ 297
Leak Survey	$ 1,444	$ -	$ -	$ -	$ -
Atmospheric Corr Inspections	$ 218	$ 219	$ 223	$ 223	$ 228
Gas Regulatory Admin/Supv	184	208	212	216	220
Priority Valves	114	115	116	117	119
Inspect Farm Taps	66	70	71	71	72
Total	$ 3,949	$ 2,582	$ 2,635	$ 2,643	$ 2,696

2025-2029
O&M Non Labor Integrity & Cpmpliance Expense Category ($000)

Item		2025 Plan		2026 Plan		2027 Plan		2028 Plan		2029 Plan
Operation Supervision	$	410	$	600	$	600	$	618	$	630
Pi Administration		222		166		170		175		178
Dimp Records Review		90		93		96		99		101
Pipeline Integrity		92		92		95		98		100
Records Review		50		50		52		53		54
Pipe Analysis		40		41		42		43		44
Validation Digs		30		31		32		33		34
Other		25		26		26		27		27
Total	$	959	$	1,099	$	1,113	$	1,145	$	1,168

Case Nos. 2025-00113 and 2025-00114
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Metts

2025-2029
O&M Non Labor Other Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
AGA	$ 263	$ 271	$ 276	$ 282	$ 288
DOT Gas Storage	132	144	144	144	144
DOT Assessment	124	124	126	129	132
KGA DUES	10	10	10	10	11
OT Security	105	150	150	155	158
SGA Dues	22	22	22	23	23
Gas Procurement	130	101	102	102	104
Gas Liability Claims	111	111	111	113	115
Operator Qualifications	120	133	135	138	141
Pipeline Safety Mgmt Systems	37	39	41	42	43
Other	(490)	(622)	23	25	28
Total	$ 564	$ 482	$ 1,142	$ 1,164	$ 1,186

2025-2029
Annual Cost of Sales Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Scavenger Media	$ 43	$ 964	$ 883	$ 888	$ 893
Odorant	74	74	76	78	80
Total Base Cost of Sales	**$ 117**	**$ 1,038**	**$ 959**	**$ 966**	**$ 973**
GLT Mechanism	$ 817	$ 3,186	$ 3,289	$ 3,334	$ 3,408
GSC Mechanism	312	312	316	322	329
Total Cost of Sales	**$ 1,245**	**$ 4,536**	**$ 4,564**	**$ 4,623**	**$ 4,710**

Operational Performance

Key Performance Indicators

KPI	2025 Plan
Gas Response Priority 1 Calls - Normal Business Hours (minutes)	33.3
Gas Response Priority 1 Calls - After-Hours (minutes)	31.5

Transmission
LG&E and KU Utilities
2025 Operating Plan

February 2025

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- Key Performance Indicators

Major Assumptions

- Transmission line and substation projects driven by NERC planning standards and LG&E and KU system planning guidelines ensure electric grid adequacy to reliably serve forecasted firm service requirements in light and heavy load periods.

- System Integrity & Resiliency - Enhanced transmission asset management through data-driven, risk-based investment strategy to reduce reliability risk, guide replacements and build a more resilient grid.
  - Transmission System Hardening and Resiliency Plan (TSHARP) developed to create a risk adjusted portfolio of transmission system investments

- Future economic development activity could drive the need for new transmission investments.

Major Assumptions

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- Storm Restoration expense is based on the 2019-2023 five-year average.
- Estimated depancaking expenses are based on current MISO reservations:
  - [redacted]
  - [redacted]
  - [redacted]
- Depancaking expenses could be different if actual MISO rates are different than the MISO rate forecast in the plan and/or due to regulatory and court proceedings.
- [redacted]

Savings/Efficiencies/Cost Reduction Measures

- Reduction in substation inspection cost by about 25 percent due to reduction from quarterly to a tri-annual schedule.
- Ongoing replacement of legacy power circuit breakers (oil, air-magnetic, & vacuum), allowing up to a 50% reduction in out of service diagnostic testing intervals and related costs.
- Purchase of Substation testing equipment to eliminate annual leasing expense.

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Compliance	$ 1,496	$ 375	$ 521	$ 375	$ 318
Emergency Replacement	6,412	5,428	5,488	5,544	5,601
Native Load	293	8,169	5,090	2,457	2,129
Operations Support	5,845	3,502	4,019	4,424	10,716
Proactive Replacement	142,608	297,142	341,825	332,442	328,707
Reliability	4,568	22,750	50,647	77,205	74,545
Resiliency	7,273	7,223	7,290	4,000	5,272
Trans. Expansion Plan	38,350	40,522	8,137	4,192	932
Third Party Requests	30,691	20,653	47,893	52,500	52,500
Generation Expansion Plan	16,939	5,809	-	1,750	2,691
All Other	2,127	591	560	175	171
Total Capital	$ 256,603	$ 412,166	$ 471,469	$ 485,063	$ 483,582
2024 Plan	$ 183,572	$ 300,000	$ 350,000	$ 350,000	
Change	$ (73,030)	$ (112,166)	$ (121,469)	$ (135,063)	

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Material Base Capital Variances by Year ($000)

	2024	2025	2026	2027	2028	Total 24-28
2024 BP	$ 121,922	$ 183,572	$ 300,000	$ 350,000	$ 350,000	$ 1,305,495
2025 BP	146,403	256,603	412,166	471,469	485,063	1,771,703
Lower/(Higher) than '24 BP	**$ (24,480)**	**$ (73,030)**	**$ (112,166)**	**$ (121,469)**	**$ (135,063)**	**$ (466,208)**
Primary Changes by Year:						
Emergency Replacement	$ 392	$ (1,009)	$ 24	$ 18	$ 16	$ (559)
Native Load	521	2,421	(1,602)	(2,384)	472	(572)
Proactive Replacement	(41,094)	(8,418)	(56,890)	(33,510)	(4,639)	(144,550)
Reliability	2,933	(1,474)	(10,855)	(40,985)	(72,417)	(122,798)
Trans. Expansion Plan	4,926	(24,137)	(20,543)	10,310	(2,044)	(31,487)
Third Party Requests	2,033	(29,447)	(18,272)	(47,893)	(52,500)	(146,080)
Generation Expansion Plan	3,182	(3,555)	3,493	730	35	3,884
All Other	2,628	(7,411)	(7,521)	(7,755)	(3,986)	(24,046)
Total Variances	**$ (24,480)**	**$ (73,030)**	**$ (112,166)**	**$ (121,469)**	**$ (135,063)**	**$ (466,208)**

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 17,158	$ 19,245	$ 19,893	$ 20,336	$ 20,986
Substation and Protection	3,460	5,040	5,141	5,513	4,710
Lines Asset Management	445	759	760	762	777
Storm Restoration	693	709	726	743	759
Operations and Compliance	4,155	4,368	4,469	4,573	4,674
Planning, Tariffs and Reliability Perf.	257	373	362	370	376
All Other Non-labor	52	(236)	(75)	(122)	(123)
Total O&M	**$ 26,219**	**$ 30,259**	**$ 31,277**	**$ 32,174**	**$ 32,158**

2025-2029
Annual Cost of Sales Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Independent Trans. Operator	$ 2,808	$ 2,849	$ 2,891	$ 2,934	$ 2,977
Reliability Coordinator	3,039	3,371	3,371	3,371	3,371
Depancaking	39,547	42,794	33,273	33,508	36,647
Total Cost of Sales	**$45,394**	**$49,015**	**$39,536**	**$39,814**	**$42,995**

Employee Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Dist. Subs Const. & Maint.	79	80	80	80	80
System Operations	28	29	29	29	29
Dist Relay & Protection	22	22	22	22	22
Strategy & Planning	14	15	15	15	15
Reliability Perf Stds & Tech	14	14	14	14	14
Trans Ops Eng & Outage	12	12	12	12	12
Trans. Protection & Control	11	11	11	11	11
Energy Management Sytems	10	10	10	10	10
System Engineering	9	9	9	9	9
Senior Managers	6	6	6	6	6
Policy & Tariffs	3	3	3	3	3
Project Development	2	2	2	2	2
Total Transmission	**210**	**213**	**213**	**213**	**213**

Supplemental Contractor Headcount by Department

Department	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Dist. Subs Const. & Maint.	3	3	3	3	3
System Operations	-	-	-	-	-
Dist Relay & Protection	-	-	-	-	-
Strategy & Planning	-	-	-	-	-
Reliability Perf Stds & Tech	-	-	-	-	-
Trans Ops Eng & Outage	-	-	-	-	-
Trans. Protection & Control	-	-	-	-	-
Energy Management Sytems	-	-	-	-	-
System Engineering	1	1	1	1	1
Senior Managers	-	-	-	-	-
Policy & Tariffs	-	-	-	-	-
Project Development	12	12	10	10	10
Total	16	16	14	14	14

2025-2029
O&M Non Labor Substation Maintenance Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Transmission Substations	$ 1,568	$ 2,443	$ 2,383	$ 2,820	$ 2,010
Transmission Protection	51	77	79	81	82
Distribution Substations	1,537	2,115	2,253	2,197	2,198
Distribution Relay & Protection	150	214	232	224	226
Substation Engineering Service	70	120	120	120	122
Total	$ 3,377	$ 4,970	$ 5,068	$ 5,443	$ 4,639

2025-2029
O&M Non Labor Lines Asset Management and Storm Restoration Expense Category ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Switch Maintenance	$ -	$ 212	$ 212	$ 212	$ 216
PSC Inspections	142	242	242	242	247
Underground	2	2	2	2	2
GIS Software	61	62	64	65	66
Easements	240	240	240	240	245
Total	$ 445	$ 759	$ 760	$ 762	$ 777
Storm Restoration	$ 693	$ 709	$ 726	$ 743	$ 759

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2025-2029
O&M Non Labor Operations & Compliance Expense Category ($000)

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Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
FERC	$ 1,247	$ 1,276	$ 1,305	$ 1,335	$ 1,366
NERC & SERC	1,499	1,649	1,687	1,726	1,765
[redacted] Reactive Power	223	223	223	227	232
System Operations - OATI	484	502	517	532	543
OSI/Primate/AVI BARCO	330	345	362	370	377
All Other	372	374	375	383	391
Total	$ 4,155	$ 4,368	$ 4,469	$ 4,573	$ 4,674

2025-2029
O&M Non Labor Planning Tariffs & Investment Strategy Expense Category ($000)

Item		2025 Plan		2026 Plan		2027 Plan		2028 Plan		2029 Plan
Outside Services Labor	$	129	$	79	$	79	$	82	$	83
Training Travel Meals		68		182		182		186		190
Computer / Communications		9		90		92		95		97
All Other		51		22		8		7		7
Total	$	257	$	373	$	362	$	370	$	376

2025-2029
OATT Revenue

	OATT Revenues				
in thousands ($000)					
	2025	2026	2027	2028	2029
	Plan	Plan	Plan	Plan	Plan
2025 BP OATT Revenue					
3rd Party	43,649	46,404	46,031	49,473	54,076
Wholesale Customers	2,743	2,924	3,324	3,626	3,980
Joint Party Settlement	1,384	1,411	1,439	1,468	1,498
Total OATT Revenue	47,776	50,739	50,794	54,567	59,554
2024 BP OATT Revenue					
3rd Party	43,798	45,221	41,898	42,816	43,913
Wholesale Customers	2,780	2,928	3,116	3,177	3,242
Joint Party Settlement	1,445	1,474	1,504	1,534	1,565
Total OATT Revenue	48,023	49,623	46,518	47,527	48,720
Variance, Fav / (Unfav)	(247)	1,116	4,276	7,040	10,834

*Wholesale Customer denotes transmission component revenue associated with the remaining full requirements customers (Bardstown and Nicholasville)

2025-2029
OATT Revenue by Customer

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					in thousands ($000)
Revenue by Customer					
	2025	2026	2027	2028	2029
[redacted]	18,127	19,368	21,733	23,999	26,413
	2,753	2,941	3,299	3,645	4,000
	4,802	5,160	763	-	-
	840	840	840	840	840
	4,509	4,824	5,413	5,927	6,516
	15	16	18	19	21
	157	169	191	211	234
	9,426	10,034	11,227	12,339	13,535
Ancillary Service Revenue	3,020	3,052	2,547	2,493	2,518
Wholesale Customers	2,743	2,924	3,324	3,626	3,980
Joint Party Settlement	1,384	1,411	1,439	1,468	1,497
Total	47,776	50,739	50,794	54,567	59,554

2025-2029 Cost of Sales

	Cost Of Sales				
in thousands ($000)					
	2025	2026	2027	2028	2029
	Plan	Plan	Plan	Plan	Plan
2025 BP Cost of Sales					
ITO	2,808	2,849	2,892	2,934	2,977
RC	3,039	3,371	3,371	3,371	3,371
Depancaking	39,547	42,794	33,273	33,509	36,647
Total Cost of Sales	45,394	49,014	39,536	39,814	42,995
2024 BP Cost of Sales					
ITO	2,808	2,849	2,891	2,934	2,978
RC	2,887	2,931	2,974	3,019	3,064
Depancaking	34,929	36,494	25,262	26,801	29,271
Total Cost of Sales	40,624	42,274	31,127	32,754	35,313
Variance, Fav / (Unfav)	(4,770)	(6,740)	(8,409)	(7,060)	(7,682)

2025-2029
Depancaking by Customer

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					in thousands ($000)
Depancaking by Customer					
	2025	2026	2027	2028	2029
[redacted]	13,251	14,332	2,413	-	-
	9,770	10,576	11,464	12,442	13,600
	16,526	17,886	19,396	21,067	23,047
Total	39,547	42,794	33,273	33,509	36,647

LG&E KU PPL companies

2025-2029
Depancaking by Customer – Plan to Plan

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in thousands ($000)					
	2025	2026	2027	2028	2029
	Plan	Plan	Plan	Plan	Plan
2025 BP Depancaking					
[redacted]	13,251	14,332	2,413	-	-
	9,770	10,576	11,464	12,442	13,600
	16,526	17,886	19,396	21,067	23,047
Total Depancaking Expense	39,547	42,794	33,273	33,509	36,647
	2025	2026	2027	2028	2029
	Plan	Plan	Plan	Plan	Plan
2024 BP Depancaking					
[redacted]	11,803	12,332	-	-	-
	8,719	9,105	9,513	10,100	11,072
	14,407	15,057	15,749	16,701	18,199
Total Depancaking Expense	34,929	36,494	25,262	26,801	29,271
Variance, Fav / (Unfav)	(4,618)	(6,300)	(8,011)	(6,708)	(7,376)

2025-2029
Plan-over-Plan Margin Variance

	Net OATT Margin				
in thousands ($000)					
	2025	2026	2027	2028	2029
2025 BP	2,382	1,725	11,258	14,753	16,559
2024 BP	7,399	7,349	15,391	14,773	13,407
Variance, Fav / (Unfav)	(5,017)	(5,624)	(4,133)	(20)	3,152
	-67.81%	-76.53%	-26.85%	-0.14%	23.51%

LG&E KU
PPL companies

Cost of Sales Annual Expense Reconciliation ($000)

	2025	2026	2027	2028
2025 Business Plan (pg. 9)	$ 45,394	$ 49,015	$ 39,536	$ 39,814
2024 Business Plan	40,624	42,274	31,127	32,754
Change	$ (4,769)	$ (6,741)	$ (8,409)	$ (7,059)
Drivers:				
Depancaking	$ (4,618)	$ (6,300)	$ (8,012)	$ (6,707)
Independent Transmission Operator	-	-	-	-
Reliability Coordinaor	(152)	(441)	(397)	(352)
Total Drivers	$ (4,769)	$ (6,741)	$ (8,409)	$ (7,059)

Operational Performance

Key Performance Indicators

KPI	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Annual SAIDI	3.95	4.38	4.20	4.17	4.25
Annual SAIFI	0.065	0.067	0.067	0.066	0.067
Annual CAIDI	60.77	65.65	62.72	63.07	63.81

Information Technology
LG&E and KU Utilities
2025 Operating Plan

February 2025

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Major Assumptions

- Managed Services Partnership
  - PPL is partnering with an industry leader in technology managed services that facilitates rapid adoption of advanced IT service management methods of operations to reduce operating costs. The Managed Services Agreement includes a commitment on the part of Accenture to reduce PPL's IT operations costs by 50% over a five-year span.

- IT Investment Profile
  - Stabilizing the current technology landscape drives service reliability for customers and enables reinvestment into opportunities to drive additional service benefits for customers.
  - The IT Reinvention will generate cost-savings for customers by consolidating software licensing, streamlining support staff, reducing time spent on rote tasks, automating processes, and reducing customer service O&M.

- IT Upskilling & Efficiencies
  - PPL is focusing on ensuring services meet or exceed industry standard by improving planning and ways of working, upskilling the workforce, and driving a common user experience across technology platforms. This will enable a more robust customer experience for all customer contact channels. By reducing the headcount dedicated to day-to-day operations and cutting IT operation costs, the Managed Services Agreement will free up PPL employee capacity for investment in skills training as well as identifying and implementing its new consolidated platforms.

- CIS & CX Transformation
  - Faster issue resolution and reduced service interruptions improve reliability and overall satisfaction.
  - More reliable service with fewer outages ensures continuous, high-quality energy delivery.
  - This initiative will invest approximately $159M over five years to bring this stabilization and reliability to our customers.

Major Assumptions

- ERP Consolidation – HR, GL, & SCM
  - This project will drive processing efficiencies in routine HR transactions, enabling the shift of HR's focus to value-add activities from transactional interactions.
  - Standardizing ERP will cut complexity, streamline operations, and reduce O&M costs.
  - This initiative will invest approximately $58M over five years to stabilize and reduce complexity of these systems. Standardizing on a single vendor for these products reduces operating costs.

- Work & Asset Management Consolidation:
  - Drive service reliability and improved response time by automating the scheduling, dispatching, and routing of field worker line crews.
  - Investment of approximately $23M in the five-year BP to improve responsiveness for scheduled work.

- Field Time Workforce & Payroll:
  - Significantly reduced amount of clerical labor by digitizing time entry will drive O&M benefits.

- Intelligent Operations
  - Implement Fault Location, Isolation, & Service Restoration (FLISR) and Volt/Var Optimization (VVO)/Conservation Voltage Reduction (CVR) across all OpCos, enabling the use of data, AI and automation to improve power quality and energy efficiency

OKRs Rooted in Reinvention Imperatives

- Enterprise Objectives & Key Results (OKRs) were defined for each Reinvention Imperative. These are initiative-agnostic and relevant for the entire enterprise. A PPL and Accenture Owner was defined for each Imperative to define these OKRs.

Reduce Net Run Costs	Stabilize & Drive Operational Excellence	Improve Planning & Ways of Working with SAFe (Scaled Agile Framework)	Increase Financial Visibility & Transparency
Upskill Workforce	Allocate Capital for Growth & Innovation	Improve Ease of Doing Business for our Customers & Colleagues	Deliver Business Outcomes Across Value Streams

2025-2029 Capital Expenditures ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
CIS Transformation	$ 23,165	$ 41,914	$ 41,536	$ 25,677	$ -
CX Transformation	$ 8,884	$ 8,762	$ 8,727	$ -	$ -
Data and AI Transformation	$ 4,814	$ 6,301	$ 5,029	$ 3,875	$ 3,875
ERP Consolidation -Corp financial and enterprise GL, HR, SCM	$ 15,299	$ 36,417	$ 6,083	$ -	$ -
Extend ServiceNow	$ 5,127	$ 1,722	$ 861	$ 1,566	$ -
Hosting strategy	$ 9,597	$ 10,818	$ 7,045	$ 5,479	$ 5,479
Intelligent Grid Operations across OnePPL	$ 14,706	$ 11,769	$ 1,611	$ 8,771	$ 960
Metering Modernization	$ -	$ -	$ 4,047	$ 1,522	$ 1,520
Work and Asset Management Consolidation	$ 11,275	$ 11,776	$ -	$ -	$ -
IT Reinvention	$ 17,670	$ 19,180	$ 16,104	$ 13,635	$ 11,710
Other	$ 36,223	$ 36,279	$ 29,026	$ 26,944	$ 21,009
Total Capital	**$146,759**	**$184,939**	**$120,068**	**$87,468**	**$44,553**
2024 Plan	$53,561	$55,031	$140,021	$115,859	
Change	($93,198)	($129,908)	$19,953	$28,391	

* Other includes standard annual refresh projects

2025-2029
Annual O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 2,117	$ 2,183	$ 2,255	$ 2,322	$ 2,399
Supplemental Contractors	$ 654	$ 654	$ 654	$ 455	$ 455
HW SW Maint & SaaS [1]	$ 21,443	$ 22,842	$ 23,135	$ 23,798	$ 25,059
Allocated PPL Charges [2]	$ 27,431	$ 34,416	$ 32,670	$ 28,102	$ 24,439
All Other Non-labor	$ 2,849	$ 2,883	$ 2,902	$ 2,925	$ 2,940
Total O&M	**$ 54,494**	**$ 62,979**	**$ 61,617**	**$ 57,601**	**$ 55,292**

HW SW Maint & SaaS [1] - Amortization expense related to Hardware and Software Maintenance plus amortization of Software as a Service contracts

Allocated PPL Charges [2] - See next slide for breakdown

Doesn't include departments tranfered into IT (R&D, Enterprise Security, Physical Security, Data/Analytics)

2025-2029
Annual PPL Allocated O&M Expenses ($000)

Item	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Labor	$ 11,630	$ 10,749	$ 11,073	$ 11,406	$ 11,747
Outside Services	$ 6,913	$ 10,252	$ 9,503	$ 7,575	$ 4,739
HW SW Maint & SaaS[1]	$ 8,453	$ 12,877	$ 11,577	$ 8,652	$ 7,502
All Other Non-Labor	$ 435	$ 538	$ 517	$ 470	$ 451
Total O&M	**$ 27,431**	**$ 34,416**	**$ 32,670**	**$ 28,102**	**$ 24,439**

HW SW Maint & SaaS [1] - Amortization expense related to Hardware and Software Maintenance plus amortization of Software as a Service contracts

Headcount by Department

	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Full Time Employees	**21**	**21**	**21**	**21**	**21**
Telecommunications - LGE *	9	9	9	9	9
Telecommunications - KU *	12	12	12	12	12
Supplemental Contractors	**8**	**8**	**8**	**7**	**7**
Transport Engineering	6	6	6	6	6
IT Training	1	1	1	1	1
IT Development and Support	1	1	1	-	-

* Note: these employees are Union Telecom Technicians.

2025-2029
O&M HW SW Maintenance and Saas ($000)

Line of Business	Primary	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan
Customer Services	SAP, Avaya	$ 3,528	$ 3,864	$ 3,987	$ 4,215	$ 4,385
Distribution	GE, SPL/NMS/DMS, Rand W	$ 3,232	$ 3,370	$ 3,403	$ 4,072	$ 4,481
Energy Supply & Analysis	nMarket, Aligne Fuels	$ 421	$ 336	$ 349	$ 364	$ 379
Finance	Oracle, Powerplan	$ 2,213	$ 2,311	$ 2,390	$ 2,484	$ 2,581
General Counsel	Acquia Enterprise Services	$ 81	$ 81	$ 81	$ 81	$ 81
Generation Services	LOTO, CIM	$ 407	$ 410	$ 519	$ 505	$ 531
Human Resources	PeopleSoft	$ 438	$ 456	$ 474	$ 493	$ 513
IT Company	Java, Stackvision, ALM	$ 1,072	$ 1,323	$ 1,381	$ 1,502	$ 1,510
IT Infrastructure	Trace3, Prosys Info Systems	$ 5,730	$ 6,432	$ 5,663	$ 4,486	$ 4,620
IT Security	NERC(Crisp), Insight Direct	$ 1,795	$ 1,663	$ 1,804	$ 1,892	$ 1,970
MAM	Watt-Net (MAM)	$ 142	$ 162	$ 169	$ 175	$ 182
Power Production	Maximo	$ 1,014	$ 1,317	$ 1,425	$ 1,547	$ 1,676
Transmission	Cascade,PowerBase and RT	$ 951	$ 631	$ 951	$ 1,427	$ 1,483
Sales Tax		$ 420	$ 488	$ 540	$ 556	$ 666
Total		**$ 21,443**	**$ 22,842**	**$ 23,135**	**$ 23,798**	**$ 25,059**

* Does not include PPL Allocation

O&M Annual Expense Reconciliation ($000)

	2025	2026	2027	2028
2025 Business Plan (pg. 9)	$ 54,494	$ 62,979	$ 61,617	$ 57,601
2024 Business Plan	$ 65,013	$ 67,514	$ 70,618	$ 72,711
Change	$ 10,519	$ 4,535	$ 9,001	$ 15,110
Drivers:				
Regulatory Assets IT Projects	$ 6,963	$ 7,555	$ 5,345	$ 3,313
Labor	$ 3,991	$ 5,752	$ 6,024	$ 6,358
Outside Services	$ 1,257	$ (3,066)	$ (757)	$ 3,670
HW SW Maint. & SaaS	$ (1,461)	$ (5,341)	$ (1,288)	$ 2,062
All Other Non-Labor	$ (231)	$ (366)	$ (323)	$ (293)
Total Drivers	$ 10,519	$ 4,534	$ 9,001	$ 15,110

Notes: Favorability is attributed to reduction in labor associated with the managed services agreement and efficiencies created by this change. Also, a change in handling of some expenses and reclassifying them as regulatory assets is also resulting in O&M favorability.