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a PPL company

<u>VIA ELECTRONIC TARIFF FILING SYSTEM</u>

Ms. Linda Bridwell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8294

October 31, 2023

Re: Revised Kentucky Utilities Company Purchase Rates for Small Capacity and Large Capacity Cogeneration and Power Production Qualifying Facilities and NMS-2 Credit Rates

Dear Ms. Bridwell:

Pursuant to the Commission's Order dated September 24, 2021 in Case No. 2020-00349[1], page 38[2], Kentucky Utilities Company ("KU") files herewith revised sheets of its Tariff P.S.C. No. 20 Original Sheet Nos. 55, 55.1, 56, 56.1, and 58, effective with service rendered on and after January 1, 2024.

This filing is being made to revise the Energy and Capacity rates for both Small Capacity Cogeneration and Small Power Production Qualifying Facilities ("SQF") and Large Capacity Cogeneration and Large Power Production Qualifying Facilities ("LQF"), as well as the dollar-denominated bill credit rate for Net Metering Service-2 ("NMS-2"). As supporting documentation for these revisions and to comply with 807 KAR 5:054, Section 5(2)(b) and (c), the attached information is also being filed:

(1) Report detailing the derivation of the proposed LQF, SQF, and NMS-2 rates, including public and confidential versions of all supporting work papers;
(2) Clean tariff;
(3) Redline tariff;
(4) A copy of the notice provided to Kentucky Press Association, Inc. ("Kentucky Press") for publication once a week for three consecutive weeks, which began the week of October 24, 2023. KU will supplement this filing with proof of notice publication when all such publication is complete. This notice complies with 807 KAR 5:011 Section 8.

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[1] *Case No. 2020-00349* – Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit
[2] "Because LG&E/KU intend to refile their avoided cost rates every two years, the Commission finds that LG&E/KU will refile avoided cost rates beginning in the fall of 2023."

On October 31, 2023, this filing was delivered for exhibition and public inspection at the Lexington business office.

On October 31, 2023, KU posted on its website a copy of the filing and a hyperlink to the location on the Commission's website where the documents and tariff filings are available.

Included in this filing is a Petition for Confidential Protection regarding certain information submitted with this filing. Pursuant to 807 KAR 5:001, Section 13(2)(e), the confidential material that is the subject of this Petition is not included in the electronic submission of this filing. The original Petition in paper medium and one copy of the confidential information are also being filed under separate cover.

Please let me know if you have any questions regarding this filing.

Sincerely,

Michael E. Hornung

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF KENTUCKY UTILITIES COMPANY RE STANDARD RATE RIDERS SQF, LQF, AND NMS-2	))))	**TFS 2023-00______**

PETITION OF
KENTUCKY UTILITIES COMPANY
FOR CONFIDENTIAL PROTECTION

Kentucky Utilities Company ("KU" or the "Company") petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001, Section 13, 807 KAR 5:011, Section 14, and KRS 61.878(1) to grant confidential protection to the items described herein, which KU is providing as exhibits to its tariff filing concerning Standard Rate Riders SQF, LQF, and NMS-2. In support of this Petition, the Company states as follows:

Confidential or Proprietary Commercial Information (KRS 61.878(1)(c)(1))

1. The Kentucky Open Records Act exempts from disclosure certain records which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records.[1] Public disclosure of the information identified herein would, in fact, prompt such a result.

2. Attachments B-E contain projections of what the Company expects to pay and receive for commodities it buys and sells like fuel and coal combustion residuals ("CCR"). If the Commission grants public access to this information, KU could be disadvantaged in negotiating contracts to buy or sell these commodities in the future. The Company could also be disadvantaged in the wholesale energy market because fuel costs are important components of energy pricing.

[1] KRS 61.878(1)(c)(1).

All such commercial harms would ultimately harm KU's customers, who would have to pay higher rates if the disclosed information resulted in higher fuel prices or adversely affected the Company's off-system energy sales. The Commission has historically recognized the need for confidential treatment of fuel cost projections,[2] as well as CCR prices.[3]

3. Attachments B and D include unit maintenance schedules, the disclosure of which would unfairly advantage the Company's competitors for wholesale power sales. This information would allow the Company's competitors to know when generating plants will be down for maintenance and thus know a crucial input into the Company's generating costs and need for power and energy during those periods. The commercial risk of the disclosure of this information is that potential suppliers will be able to manipulate the price of power bid to the Company in order to maximize their revenues, thereby causing higher prices for the Company's customers and giving a commercial advantage to KU's competitors. The Commission has historically recognized the need for confidential treatment of unit maintenance schedules.[4]

4. Attachments B and D contain proprietary information obtained from a third-party, IHS Markit, related to emissions allowance pricing. As a participant in a competitive market, this third party does not want confidential technical information or projections it has made to be publicly disclosed or to be used against it in future negotiations with other customers or by its

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[2] *See, e.g.*, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, Order at 3 (Ky. PSC Dec. 6, 2022); *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Order at 3 (Ky. PSC Nov. 16, 2018).

[3] *See Electronic Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Approval of Amendment to Its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2017-00483, Order at 1-2 (Ky. PSC Apr. 30, 2018).

[4] *See, e.g.*, *Electronic Review of the Adequacy of Kentucky's Generation Capacity and Transmission System*, Administrative Case No. 387, Order at 2 (June 20, 2023); *An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from May 1, 2021 through October 31, 2021*, Case No. 2022-00041, Order at 2-3 (Ky. PSC Jan. 10, 2023).

competitors. If this proprietary information is disclosed, this party and other third-party suppliers of the same kinds of information and analyses may be less willing to supply reports to the Company in the future. Diminishing the Company's ability to receive this information would harm both the Company and its customers. The Commission has historically recognized the need for confidential treatment of proprietary third-party information.[5]

5. Attachments C-E contain commercially sensitive third-party information from the Ohio Valley Electric Corporation ("OVEC") related to power cost. Publicly disclosing this information could adversely impact OVEC participants' ability to compete effectively in the wholesale energy marketplace. These competitive harms could also adversely affect the Company's customers because the Company is contractually obligated to purchase certain amounts of energy from OVEC, the total cost of which is affected by the amount of power OVEC participants use for their own customers or are able to sell. The Commission has historically recognized the need for confidential treatment of this kind of sensitive third-party information.[6]

6. Attachments B-E include commercially sensitive solar production data that was provided by solar developers in response to one of the Company's requests for proposals ("RFPs"). This information is proprietary to the vendors and is commercially sensitive confidential information because it provides insight into the methodology used by a particular developer to model energy production over time, as well as the performance characteristics of the underlying solar technology, which in turn is a key input used to calculate sensitive pricing terms. Disclosure of this information will result in a competitive disadvantage to the Company because it will limit

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[5] *See, e.g.*, *Electronic 2019 Integrated Resource Plan of East Kentucky Power Cooperative, Inc.*, Case No. 2019-00096, Order at 4 (Ky. PSC Apr. 1, 2020); *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Order at 1-3 (Ky. PSC Nov. 16, 2018).
[6] *See, e.g.*, *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2014-00372, Order at 2-3 (Ky. PSC Apr. 28, 2015); *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Order at 3 (Ky. PSC Apr. 3, 2020).

the Company's ability to obtain this valuable study data and to maintain relationships with third-party solar developers. If commercially sensitive solar production information does not remain free from public disclosure, third-party vendors may be discouraged from engaging in future RFP processes with the Company, which would ultimately harm the Company's ability to participate in the marketplace, and could result in a less competitive RFP process with higher costs passed onto customers. The Commission has historically recognized the need for confidential treatment of solar production data.[7]

7. Attachments C-E contain information on the agreed upon rates that the Company will pay for solar energy. Public disclosure of pricing information will place the Company at a considerable disadvantage when negotiating future contracts, to the detriment of the Company's customers. Furthermore, public disclosure will provide insight into the Company's evaluation of bids for such contracts to the detriment of the Company and its ratepayers. Additionally, disclosing this information will likely reduce the willingness of the vendors and similar entities to contract or otherwise transact business with the Company in the future. The public disclosure of this information will create precisely the kind of competitive harm KRS 61.878(1)(c)(1) intends to prevent. Because solar development continues to be an emerging field, the commercial terms involved in solar contracts have yet to mature into standard terms. Solar contracts often involve extensive negotiations of commercial terms that may be generally standardized in other industries, such as in contracts involving the purchase of coal. Coal contracts, in comparison, have had more time to develop and mature because of coal's iterative presence in the energy industry, resulting in more contract terms that may be considered "boilerplate" or standard in the negotiation phase.

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[7] *See Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief*, Case No. 2020-00174, Order at 3-4 (Ky. PSC Oct. 26, 2020, 8:55:31 AM).

Solar contracts have not matured to the same degree. Because of the incipient nature of solar contracts, public disclosure of commercially sensitive terms permits an exceptionally unfair commercial advantage to competitors of solar developers in contravention of KRS 61.878(1)(c)(1). In light of the distinctive context of solar contracts, the Company requests such information not be disclosed until the costs are proposed for recovery.[8]

Critical Infrastructure Information (KRS 61.878(1)(m)(1))

8. KRS 61.878(1)(m)(1) exempts from disclosure public records that have a reasonable likelihood of threatening public safety by exposing a vulnerability, such as infrastructure records that disclose the "location, configuration, or security of critical systems," or "detailed drawings, schematics, maps, or specifications of structural elements, floor plans, and operating, utility, or security systems."

9. Attachments B and D contain critical energy infrastructure information ("CEII") regarding KU's transmission infrastructure, namely the transmission capacity constraint between KU and its sister utility, Louisville Gas and Electric Company ("LG&E"). The disclosure of these documents could expose a vulnerability through the disclosure of the configuration of public utility critical systems. If such information is made available in the public record, individuals seeking to induce public harm will have critical information concerning the present vulnerabilities of the Company's transmission system. Knowledge of such vulnerabilities may allow a person to cause

[8] *But see Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2022-00402, Order at 17 (Ky. PSC Aug. 31, 2023) (denying confidential treatment for information relating to solar PPAs); Case No. 2022-00402, Order at 5 (Ky. PSC Oct. 10, 2023) (denying motion for reconsideration of the Commission's August 31, 2023 Order regarding the confidential treatment of solar PPA information). The Company maintains the position that its rationale for requesting confidential protection of solar energy pricing information has merit, and the Company's right to bring an action in Franklin Circuit Court to review the Commission's determination has yet to expire. Consequently, the Company respectfully sets forth the same reasoning as it did in Case No. 2022-00402 for the confidential protection of this sensitive commercial information.

public harm through the disruption of the electric transmission system. The Commission has historically recognized the need for confidential treatment of sensitive transmission information.[9]

Confidential Information Subject to this Petition

10. With the exception of third-party information provided to the Company in confidence, the information for which the Company is seeking confidential treatment is not known outside of KU and LG&E, their consultants with a need to know the information, and the Company's counsel, is not disseminated within KU and LG&E except to those employees with a legitimate business need to know and act upon the information, and is generally recognized as confidential and proprietary information in the energy industry.

11. The Company will disclose the confidential information, pursuant to a confidentiality agreement, to intervenors with a legitimate interest in this information and as required by the Commission.

12. If the Commission disagrees with this request for confidential protection, it must hold an evidentiary hearing (a) to protect the Company's due process rights and (b) to supply the Commission with a complete record to enable it to reach a decision with regard to this matter.[10]

13. Pursuant to 807 KAR 5:001, Section 13(2)(b), the Company is filing with the Commission one electronic copy that identifies with redactions the information for which confidential protection is sought. The Company will transmit the unredacted versions of the confidential information to the Commission's Executive Director via electronic mail noting the confidential information with highlighting.

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[9] *See, e.g., Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Order at 3 (Ky. PSC Nov. 16, 2018); Case No. 2018-00348, Order at 2-3 (Ky. PSC Apr. 3, 2020).

[10] *Utility Regulatory Commission v. Kentucky Water Service Company, Inc.*, 642 S.W.2d 591, 592-94 (Ky. App. 1982).

14. Due to the serious security concerns related to the disclosure of Critical Infrastructure Information, KU requests that the Critical Infrastructure Information contained in Attachments B and D remain confidential indefinitely. Because of the unique nature of solar contracting terms, the Company requests that the solar energy rate information contained in Attachments C and E remains confidential until the costs are proposed for recovery. For all other requests for confidential protection, the Company requests that confidential protection be granted for five years due to the sensitive nature of the information at issue.

WHEREFORE, Kentucky Utilities Company respectfully requests that the Commission issue an order granting protection from public disclosure for the confidential information specifically described in this petition.

Dated: October 31, 2023

Respectfully submitted,

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Counsel for Kentucky Utilities Company

CERTIFICATE OF SERVICE

In accordance with the Commission's Order of July 22, 2021 in Case No. 2020-00085 (Electronic Emergency Docket Related to the Novel Coronavirus COVID-19), this is to certify that the electronic filing has been transmitted to the Commission on October 31, 2023, and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

Counsel for Kentucky Utilities Company

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE
In all territory served.

AVAILABILITY
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.

DEFINITIONS
"As-available" describes energy purchases from Seller when Seller has not entered into a PPA with Company.

"Other Technologies" means all electric power generating technologies encompassed in the definition of "qualifying facility" in 807 KAR 5:054 Section 1(8) other than solar and wind.

RATES FOR PURCHASES FROM SELLER UNDER PPA

Energy Rates ($/MWh)

	Distribution Connected Projects		Transmission Connected Projects		
Technology	**2-Year PPA**	**7-Year PPA**	**2-Year PPA**	**7-Year PPA**	
Solar: Single-Axis Tracking	30.43	32.16	29.05	30.71	I/I/I/I
Solar: Fixed Tilt	30.73	32.56	29.33	31.09	I/I/I/I
Wind	29.27	31.55	27.94	30.11	I/I/I/I
Other Technologies	29.39	31.96	28.05	30.50	I/I/I/I

RATES FOR PURCHASES FROM SELLER UNDER PPA (Continued)

Capacity Rates ($/MWh)

Technology	Distribution Connected Projects 2-Year PPA	Distribution Connected Projects 7-Year PPA	Transmission Connected Projects 2-Year PPA	Transmission Connected Projects 7-Year PPA	
Solar: Single-Axis Tracking	0	12.26	0	11.51	R/R
Solar: Fixed Tilt	0	14.76	0	13.86	R/R
Wind	0	9.66	0	9.08	R/R
Other Technologies	0	8.54	0	8.03	R/R

The Energy and Capacity rates stated above will be combined to equal the All-In Rate for payment to Seller.

RATES FOR ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Rates for energy purchases from Seller on an as-available basis are based upon the applicable 2-year PPA.

PAYMENT

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

TERM OF CONTRACT

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.

PARALLEL OPERATION

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

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY

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 greater than 100 kW.

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.

RATES HEREIN ARE ADVISORY

Pursuant to 807 KAR 5:054 Section 7(4), the rates set forth herein are solely the basis for negotiating final purchase rates with Seller.

DEFINITIONS

"As-available" describes energy purchases from Seller when Seller has not entered into a PPA with Company.

"Other Technologies" means all electric power generating technologies encompassed in the definition of "qualifying facility" in 807 KAR 5:054 Section 1(8) other than solar and wind.

RATES FOR PURCHASES FROM SELLER UNDER PPA
Energy Rates ($/MWh)

	Distribution Connected Projects		Transmission Connected Projects		
Technology	**2-Year PPA**	**7-Year PPA**	**2-Year PPA**	**7-Year PPA**	
Solar: Single-Axis Tracking	30.43	32.16	29.05	30.71	I/I/I/I
Solar: Fixed Tilt	30.73	32.56	29.33	31.09	I/I/I/I
Wind	29.27	31.55	27.94	30.11	I/I/I/I
Other Technologies	29.39	31.96	28.05	30.50	I/I/I/I

RATES FOR PURCHASES FROM SELLER UNDER PPA (Continued)

Capacity Rates ($/MWh)

Technology	Distribution Connected Projects 2-Year PPA	Distribution Connected Projects 7-Year PPA	Transmission Connected Projects 2-Year PPA	Transmission Connected Projects 7-Year PPA	
Solar: Single-Axis Tracking	0	12.26	0	11.51	R/R
Solar: Fixed Tilt	0	14.76	0	13.86	R/R
Wind	0	9.66	0	9.08	R/R
Other Technologies	0	8.54	0	8.03	R/R

The Energy and Capacity rates stated above will be combined to equal the All-In Rate for payment to Seller.

RATES FOR ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Rates for energy purchases from Seller on an as-available basis are based upon the applicable 2-year PPA.

PAYMENT

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

TERM OF CONTRACT

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.

PARALLEL OPERATION

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

APPLICABLE
In all territory served.

AVAILABILITY
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.

BILLING
All Customer bills will be calculated in accordance with the Customer's standard rate schedule

ENERGY RATES & CREDITS
For each billing period, Company will net the dollar value of the total energy consumed and the dollar value of the total energy exported by Customer as follows: Company will (a) bill Customer for all energy consumed from Company in accordance with Customer's standard rate and (b) Company will provide a dollar-denominated bill credit for each kWh Customer produces to the Company's grid.

Dollar-denominated bill credit:	$0.07468 per kWh	I

The dollar-denominated bill credit will be applied only to the energy charge and any riders that are based on a per kWh charge. Any bill credits not applied to a Customer's bill in a billing period are "unused excess billing-period credits." Any unused excess billing-period credits will be carried forward and drawn on by Customer as needed.

Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between Customers or locations. For joint accounts, unused excess billing-period credits will be carried forward as long as at least one joint account holder remains in the same location.

TERMS AND CONDITIONS
Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto. The Net Metering Service Interconnection Guidelines applicable to this Rider are at Sheet Nos. 108 *et seq.*

2024-2025
Qualifying Facilities Rates & Net Metering Service-2 Bill Credit

PPL companies

Generation Planning & Analysis

October 2023

Table of Contents

1 Introduction

According to the Public Utility Regulatory Policies Act of 1978 ("PURPA") as implemented in Kentucky by Commission regulations, Louisville Gas and Electric Company and Kentucky Utilities Company (collectively, "the Companies") have an obligation to purchase the electrical output of certain types and sizes of renewable or cogeneration electric generating facilities at the utility's avoided cost; such facilities are qualifying facilities ("QFs").[1] For example, the Commission's QF regulation obligates a serving utility to purchase the output of a renewable generator of up to 80 MW under certain conditions.[2] In compliance with the Commission's QF regulation, the Companies' have two QF standard rate riders:

- SQF – for small (100 kW or less) QFs and
- LQF – for QFs greater than 100 kW.

The Commission's QF regulation is clear that compensation for QFs "shall be based on avoided costs."[3] The regulation defines avoided costs to be "incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source."[4] Avoided energy and capacity costs are provided for the following QF technologies: single-axis tracking solar, fixed tilt solar, wind, and other fully-dispatchable technologies ("other technologies").

2 Avoided Energy Cost

The Companies evaluated the impact on system energy costs for each Qualifying Facility ("QF") technology using forecasted hourly energy costs developed in PROSYM. To focus the analysis on the cost of serving native load, off-system sales were not permitted in PROSYM. With this exception, all assumptions for computing hourly energy costs were taken from the Companies' 2024 Business Plan ("BP").[5] In the 2024 BP, the Companies' resource plan through 2028 assumes approval of the resource portfolio the Companies proposed in Case No. 2022-00402.[6] Beyond 2028, the Companies' remaining coal units were assumed to be retired at the end of their depreciable lives and replaced with NGCC units as needed to maintain minimum 17% summer and 24% winter reserve margins.

Avoided energy costs include the cost of fuel, emission control reagents (e.g., limestone, ammonia), emission allowance costs, and an opportunity cost for lost CCR revenues.[7] Table 1 lists the QF technologies for which avoided energy costs were computed and their assumed capacity factors for resources sited in Kentucky. The QF generation profiles were developed to ensure the profiles are properly correlated with load (i.e., both load and the renewable generation profiles are forecasted based on a common set of

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[1] *See* 807 KAR 5:054.
[2] *See, e.g.,* 807 KAR 5:054 Section 1(10).
[3] *See* 807 KAR 5:054 Section 7(2) and (4).
[4] 807 KAR 5:054 Section 1(1).
[5] Attachment A contains a description of the Companies' 2024 BP generation forecast process. Attachments B-E contain 2024 BP model inputs and outputs in Excel and native formats.
[6] *See, e.g., Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Application (Dec. 15, 2022). The 100 MW Rhudes Creek and 125 MW Ragland solar projects were also included beginning January 2025.
[7] The cost of fuel accounts for approximately 90% of total avoided energy costs.

temperature, solar irradiance, and wind speed data). A generation profile was developed for each QF technology with an assumed nameplate capacity of 80 MW, the maximum nameplate capacity for a QF.

Table 1: QF Generation Technologies

Technology	Capacity Factor
Solar: Single-Axis Tracking	26.0%
Solar: Fixed Tilt	16.7%
Wind	25.3%
Other Technologies	Varies

To compute the avoided cost of energy for each generation technology, the Companies first computed the decremental cost of energy for each megawatt-hour ("MWh") of generation in each hour of the forecast period (2024-2044). Then, for each hour and generation technology, the avoided cost of energy was computed with the assumption that the highest-cost energy would be avoided first. For example, in an hour where the QF technology was assumed to produce 40 MWh, the Companies sorted each MWh from highest to lowest cost and computed the avoided cost of energy as the sum of decremental energy costs for the top 40 MWh.

The results of this analysis are summarized in Table 2. For each technology, the average avoided energy cost for each year of the analysis period was computed by dividing total avoided costs by total generation. Avoided energy costs for the QF technologies are very similar.

Table 2: Annual Avoided Energy Cost ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2024	27.36	27.53	26.92	26.49
2025	30.75	31.14	28.97	29.62
2026	30.85	31.27	28.41	29.66
2027	30.98	31.58	29.34	30.33
2028	29.73	30.32	28.37	29.08
2029	28.89	29.48	27.99	28.68
2030	29.49	30.01	28.34	29.13
2031	29.89	30.31	29.02	29.73
2032	30.48	30.94	29.72	30.43
2033	30.81	31.29	29.87	30.63
2034	30.50	30.93	30.19	30.42
2035	31.03	31.47	30.88	31.19
2036	31.49	31.85	31.30	31.59
2037	32.08	32.44	31.90	32.11
2038	32.62	32.91	32.77	32.83
2039	31.30	31.35	33.18	32.43
2040	31.39	31.38	32.97	32.32
2041	32.21	32.16	33.62	33.08
2042	32.72	32.68	34.32	33.64
2043	33.40	33.38	34.97	34.28
2044	34.19	34.19	36.04	35.05

To simplify administration, the avoided energy costs in Table 2 were levelized to produce the avoided energy prices shown in Table 3.[8] Table 3 shows the avoided energy prices for a 2-year PPA effective in 2024 through 2025 and for 7-year PPAs beginning in 2024 and 2025.[9]

[8] The levelized cost of energy was computed with the discount rate used to compute the present value of revenue requirements (6.55%).

[9] Avoided energy prices for the 2-year PPA are computed as the average of avoided energy costs in 2024 and 2025. Consistent with the Commission's order in Case Nos. 2020-00349 and 2020-00350, the QF PPA term is 7 years, and the avoided energy cost assigned to each 7-year PPA is the levelized avoided energy cost over the 20-year period beginning in the first year of the PPA.

Table 3: Avoided Energy Costs ($/MWh)

Technology	2-Year PPA (2024-2025)	7-Year Level Price for PPAs Beginning: 2024	2025
Solar: Single-Axis Tracking	29.05	30.51	30.90
Solar: Fixed Tilt	29.33	30.89	31.28
Wind	27.94	29.90	30.33
Other Technologies	28.05	30.27	30.74

3 Avoided Capacity Cost

For a given technology and PPA term, an avoided capacity price (in $/MWh) is computed as a function of the Companies' future need for generating capacity and the cost of new capacity. Each of these items and the method for computing levelized costs for tariff purposes are discussed in the following sections.

3.1 Future Need for Generating Capacity

The Companies' need for future generating capacity depends on load growth and the timing of generating unit retirements. Given the uncertainty associated with future environmental regulations, the timing of further unit retirements is uncertain. Therefore, the Companies computed the future need for generating capacity as the average of two retirement scenarios. In the first scenario, all remaining generating units were assumed to be retired at the end of their depreciable lives. In the second scenario, all remaining coal generating units were assumed to be retired by the end of 2031, consistent with the EPA's proposed Section 111 (d) rule, and all other remaining generating units were assumed to be retired at the end of their depreciable lives.

Table 4 summarizes the Companies' seasonal capacity need in each scenario as well as the average seasonal capacity need based on 17% summer and 24% winter reserve margins.[10] As discussed in Section 5, the Companies continue to recommend limiting QF capacity to the lower of the actual need or 1,000 MW. In addition to providing an intermittent generation "circuit breaker" for assessing grid reliability in a scenario where a large amount of QFs are constructed in the Companies' service territories, this limit recognizes that the Companies' avoided cost studies will likely need to be refined to address energy needs throughout the year and not just in peak hours. Table 22 and Table 23 in Appendix A provide a detailed summary of the Companies' summer and winter peak demand forecast, unit retirement assumptions, and capacity need for each scenario.

[10] The Companies' minimum summer reserve margin will almost certainly increase with the proposed additions of solar generation in Case No. 2022-00402. However, a higher summer reserve margin will have no impact on the timing of the Companies' 2032 capacity need.

Table 4: Seasonal Capacity Need (MW)

	Summer			Winter		
Year	Scen 1: End of Depr Life	Scen 2: Section 111(d)	Average of Scen 1 and 2	Scen 1: End of Depr Life	Scen 2: Section 111(d)	Average of Scen 1 and 2
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	0	0	0	0	0	0
2027	0	0	0	0	0	0
2028	0	0	0	0	0	0
2029	0	0	0	0	0	0
2030	0	0	0	0	0	0
2031	0	0	0	0	0	0
2032	0	1,908	954	0	2,783	1,391
2033	0	1,900	950	0	2,783	1,391
2034	0	2,014	1,007	147	2,921	1,534
2035	0	2,255	1,128	413	3,187	1,800
2036	0	2,375	1,188	542	3,315	1,928
2037	589	2,376	1,482	1,496	3,316	2,406
2038	587	2,374	1,481	1,498	3,318	2,408
2039	1,747	2,665	2,206	2,720	3,660	3,190
2040	1,895	2,814	2,354	2,879	3,819	3,349
2041	2,199	3,117	2,658	3,216	4,156	3,686
2042	2,676	3,595	3,135	3,760	4,700	4,230
2043	2,675	3,594	3,134	3,761	4,701	4,231
2044	3,152	4,071	3,612	4,299	5,239	4,769

3.2 New Capacity Cost

In Case Nos. 2020-00349 and 2020-00350, the Companies used two methods to estimate the cost of new solar capacity: (1) Current Market Price and (2) Levelized Cost of a Simple Cycle Combustion Turbine ("CT"). The Current Market Price method utilized solar PPA prices to directly calculate annual capacity prices, and the Levelized Cost of a CT method calculated capacity prices as a function of CT costs. Consistent with least-cost principles, the Companies continue to believe that QF capacity prices should be computed as the minimum capacity price from these two methods. However, based on the Commission's September 24, 2021 order, this analysis utilizes only the Levelized Cost of a CT method for all QF technologies.

The Levelized Cost of a CT method starts first by determining the annual economic carrying charge of an investment in a new CT. Because a CT is available to meet peak load in each month, the Levelized Cost of a CT method requires adjusting the annual capacity cost of a CT by each technology's ability to meet monthly peak. If this adjustment was not made, customers would be overpaying for capacity in certain months. Once each technology's annual capacity cost is determined, this value is converted to a $/MWh avoided capacity cost by dividing the annual capacity payment by each technology's annual energy production.

Table 5 summarizes the capital and fixed operating costs for a new CT. Overnight capital and fixed operating and maintenance ("O&M") costs are taken from the National Renewable Energy Laboratory's 2023 Annual Technology Baseline.[11] Firm gas transportation costs are based on the Companies' cost of firm gas transportation and are consistent with cost assumptions from Case No. 2022-00402.

Table 5: CT Capital and Fixed Operating Costs[11]

Cost	2032 Installation (Real 2021 $)	2032 Installation (Nominal $)
Overnight Capital ($/kW)	923	1,148
Fixed O&M ($/kW-Year)	22.6	28.1
Firm Gas Transportation ($/kW-Year)	N/A	22.6

Table 6 contains the economic carrying charge for a CT based on the cost assumptions in Table 5. 100% of these costs could be avoided if generation technologies with similar performance characteristics were added to the generation portfolio. However, solar and wind technologies are not available during the peak hour in all months. Therefore, only a portion of CT costs should be included when avoided costs are computed as a function of CT costs. Table 7 summarizes the availability of the QF resources during the peak hour for each month. The peak hour for each month is the hour in which the Companies' monthly peak most commonly occurred over the past 20 years.[12] Note that "other technologies" are assumed to be 100 percent available to meet monthly peak load.

[11] Source: https://atb.nrel.gov/electricity/2023/data. The Companies inflated NREL's cost forecasts, which were provided in real 2021 dollars, to nominal dollars at 2% annually.

[12] An alternative way to assess the availability of QF resources is to compare the resource's impact on LOLE to the LOLE impact of a like amount of SCCT capacity. This quotient is the resource's "capacity contribution" and is similar in an RTO context to an intermittent resource's Effective Load Carrying Capability ("ELCC"), which is used to assess the resource's UCAP capacity credit. In PJM, for example, ELCC for intermittent resources is computed in the context of a generation portfolio with an LOLE of 1 day per 10 years. Based on the forecasted additions of solar in PJM, the ELCC for single-axis tracking solar decreases from 56% in 2024 to 16% in 2032, the year of the Companies' assumed capacity need. See https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx for PJM's ELCC Report December 2022.

Table 6: CT Economic Carrying Charge ($/MW-Year)

Year	CT Economic Carrying Charge
2024	126,519
2025	128,071
2026	129,644
2027	131,237
2028	132,853
2029	134,490
2030	136,149
2031	137,830
2032	139,535
2033	141,262
2034	143,013
2035	144,787
2036	146,586
2037	148,409
2038	150,258
2039	152,131
2040	154,030
2041	155,955
2042	157,906
2043	159,885
2044	161,890

Table 7: Availability of QF Resources during Peak Hours (% of Nameplate Capacity)

	Monthly Peak Hour Beginning (EST)		Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
Jan	7		0.0%	0.0%	35.7%	100.0%
Feb	7		0.0%	0.0%	36.3%	100.0%
Mar	7		3.6%	0.2%	33.8%	100.0%
Apr	6		0.9%	0.0%	18.4%	100.0%
May	15		72.5%	57.7%	39.0%	100.0%
Jun	15		79.9%	65.4%	25.6%	100.0%
Jul	14		81.4%	74.1%	23.4%	100.0%
Aug	15		74.4%	59.3%	23.5%	100.0%
Sep	15		71.7%	51.4%	27.8%	100.0%
Oct	15		62.2%	37.5%	44.8%	100.0%
Nov	7		0.1%	0.0%	11.8%	100.0%
Dec	7		0.0%	0.0%	23.6%	100.0%
Annual Average			**37.2%**	**28.8%**	**28.7%**	**100.0%**
Summer Average (Jun-Aug)			**78.6%**	**66.3%**	**24.2%**	**100.0%**

In Table 8, annual avoided costs are computed for each generation technology by multiplying the CT costs in Table 6 by the average annual availability factors in Table 7 (i.e., 37.2% for single-axis tracking solar, 28.8% for fixed tilt solar, and so on).

Table 8: Annual Avoided Capacity Costs Based on CT Cost ($/MW-Year)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2024	47,089	36,438	36,257	126,519
2025	47,667	36,885	36,701	128,071
2026	48,252	37,338	37,152	129,644
2027	48,845	37,797	37,609	131,237
2028	49,446	38,262	38,072	132,853
2029	50,056	38,734	38,541	134,490
2030	50,673	39,212	39,016	136,149
2031	51,299	39,696	39,498	137,830
2032	51,933	40,187	39,987	139,535
2033	52,576	40,684	40,482	141,262
2034	53,228	41,189	40,983	143,013
2035	53,888	41,700	41,492	144,787
2036	54,558	42,218	42,007	146,586
2037	55,236	42,743	42,530	148,409
2038	55,924	43,275	43,059	150,258
2039	56,622	43,815	43,596	152,131
2040	57,328	44,362	44,141	154,030
2041	58,045	44,916	44,692	155,955
2042	58,771	45,478	45,251	157,906
2043	59,507	46,048	45,818	159,885
2044	60,254	46,625	46,393	161,890

To compute avoided capacity costs on a $/MWh basis, the annual values in Table 8 were divided by each technology's expected generation (see Table 9). The assumed capacity factors for each technology are listed in Table 1. To compute a $/MWh value for "other technologies," the annual capacity payment was divided by 8,760 hours. The avoided capacity cost for single-axis tracking solar, for example, is higher than fixed tilt solar on an annual basis but lower on a $/MWh basis. Single-axis tracking solar has a higher average annual availability during peak hours (37.2% versus 28.8%), but its higher annual avoided capacity cost is divided over significantly more MWh.

Table 9: Avoided Capacity Costs Based on CT Cost ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2024	20.71	24.94	16.33	14.44
2025	20.96	25.25	16.53	14.62
2026	21.22	25.56	16.74	14.80
2027	21.48	25.87	16.94	14.98
2028	21.75	26.19	17.15	15.17
2029	22.02	26.51	17.36	15.35
2030	22.29	26.84	17.58	15.54
2031	22.56	27.17	17.79	15.73
2032	22.84	27.51	18.01	15.93
2033	23.12	27.85	18.24	16.13
2034	23.41	28.19	18.46	16.33
2035	23.70	28.54	18.69	16.53
2036	24.00	28.90	18.92	16.73
2037	24.29	29.26	19.16	16.94
2038	24.60	29.62	19.40	17.15
2039	24.90	29.99	19.64	17.37
2040	25.21	30.36	19.88	17.58
2041	25.53	30.74	20.13	17.80
2042	25.85	31.13	20.39	18.03
2043	26.17	31.52	20.64	18.25
2044	26.50	31.91	20.90	18.48

3.3 Calculation of Avoided Capacity Prices

As noted previously, for a given technology and PPA term, the avoided capacity price is computed as a function of the Companies' future need for generating capacity and the cost of new capacity. For example, a 20-year QF PPA beginning 2025 would defer the need for capacity in 2032 by 13 years to 2045. Similarly, the same PPA would defer a 2034 capacity need by only 11 years. The sooner the capacity need, the higher the avoided capacity value.

Consistent with the Commission's order in Case Nos. 2020-00349 and 2020-00350, the avoided capacity cost for a 7-year QF PPA is computed based on a 20-year PPA term. Table 10 shows the avoided capacity costs for QF PPAs beginning in 2025 based on the Levelized Cost of a CT methodology. The first section in each table contains avoided capacity costs associated with a 2032 capacity need; the second section contains avoided capacity costs associated with a 2034 capacity need.

Table 10: Levelized Cost of a CT Avoided Capacity Costs for QF PPA Beginning 2025 ($/MWh)

	2032 Capacity Need				2034 Capacity Need			
Year	**Solar: Single-Axis Tracking**	**Solar: Fixed Tilt**	**Wind**	**Other**	**Solar: Single-Axis Tracking**	**Solar: Fixed Tilt**	**Wind**	**Other**
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032	22.84	27.51	18.01	15.93	-	-	-	-
2033	23.12	27.85	18.24	16.13	-	-	-	-
2034	23.41	28.19	18.46	16.33	23.41	28.19	18.46	16.33
2035	23.70	28.54	18.69	16.53	23.70	28.54	18.69	16.53
2036	24.00	28.90	18.92	16.73	24.00	28.90	18.92	16.73
2037	24.29	29.26	19.16	16.94	24.29	29.26	19.16	16.94
2038	24.60	29.62	19.40	17.15	24.60	29.62	19.40	17.15
2039	24.90	29.99	19.64	17.37	24.90	29.99	19.64	17.37
2040	25.21	30.36	19.88	17.58	25.21	30.36	19.88	17.58
2041	25.53	30.74	20.13	17.80	25.53	30.74	20.13	17.80
2042	25.85	31.13	20.39	18.03	25.85	31.13	20.39	18.03
2043	26.17	31.52	20.64	18.25	26.17	31.52	20.64	18.25
2044	26.50	31.91	20.90	18.48	26.50	31.91	20.90	18.48

To compute the avoided capacity cost price for a QF PPA beginning in 2025, the Companies levelized the values in Table 10 over the period 2025 to 2044. Table 11 contains the results of these calculations.

Table 11: 2025-2044 Levelized Avoided Capacity Price for QF PPA beginning in 2025 ($/MWh)

	2032 Capacity Need				2034 Capacity Need			
Method	**Solar: Single-Axis**	**Solar: Fixed Tilt**	**Wind**	**Other**	**Solar: Single-Axis**	**Solar: Fixed Tilt**	**Wind**	**Other**
Levelized Cost of a CT	12.21	14.70	9.63	8.51	9.76	11.76	7.70	6.81

This calculation was completed for QF PPAs beginning in 2024 and 2025. The final results are summarized in Table 12.

Table 12: Levelized Cost of a CT Avoided Capacity Prices ($/MWh)

2032 Capacity Need			
	2-Year PPA	7-Year PPA Beginning:	
Technology	(2024-2025)	2024	2025
Solar: Single-Axis Tracking	0.00	10.82	12.21
Solar: Fixed Tilt	0.00	13.03	14.70
Wind	0.00	8.53	9.63
Other Technologies	0.00	7.55	8.51
2034 Capacity Need			
	2-Year PPA	7-Year PPA Beginning:	
Technology	(2024-2025)	2024	2025
Solar: Single-Axis Tracking	0.00	8.53	9.76
Solar: Fixed Tilt	0.00	10.27	11.76
Wind	0.00	6.72	7.70
Other Technologies	0.00	5.95	6.81

4 Total Avoided Cost

Table 13 contains the Companies' all-in avoided cost rates based on the Levelized Cost of a CT methodology for both 2032 and 2034 capacity need scenarios.

Table 13: Levelized Cost of a CT All-In Avoided Cost Rates ($/MWh)

2032 Capacity Need			
	2-Year PPA	7-Year PPA Beginning:	
Technology	(2024-2025)	2024	2025
Solar: Single-Axis Tracking	29.05	41.33	43.10
Solar: Fixed Tilt	29.33	43.92	45.98
Wind	27.94	38.43	39.95
Other Technologies	28.05	37.82	39.25
2034 Capacity Need			
	2-Year PPA	7-Year PPA Beginning:	
Technology	(2024-2025)	2024	2025
Solar: Single-Axis Tracking	29.05	39.04	40.66
Solar: Fixed Tilt	29.33	41.16	43.04
Wind	27.94	36.62	38.03
Other Technologies	28.05	36.22	37.55

5 QF Rates

Table 14 through Table 20 reflect the Companies' updates to the Commission's recommended QF Avoided Cost Rates in their September 24, 2021 Order in Case Nos. 2020-00349 and 2020-00350, based on the Companies' 2024 Business Plan, the Levelized Cost of a CT methodology for avoided capacity cost for all technologies, and a 2032 capacity need.

Table 14: Qualifying Facility Avoided Energy Rates for Transmission Connected Projects, without Line Losses ($/MWh)

	QF Avoided Energy (without line losses for transmission connected projects)		
		7-Year PPA Beginning:	
Technology	**2-Year PPA**	**2024**	**2025**
Solar: Single-Axis Tracking	29.05	30.51	30.90
Solar: Fixed Tilt	29.33	30.89	31.28
Wind	27.94	29.90	30.33
Other Technologies	28.05	30.27	30.74

Table 15: Qualifying Facility Avoided Capacity Rates for Transmission Connected Projects, without Line Losses ($/MWh)

	QF Avoided Capacity, 2032 Need (without line losses for transmission connected projects)		
		7-Year PPA Beginning:	
Technology	**2-Year PPA**	**2024**	**2025**
Solar: Single-Axis Tracking	0.00	10.82	12.21
Solar: Fixed Tilt	0.00	13.03	14.70
Wind	0.00	8.53	9.63
Other Technologies	0.00	7.55	8.51

Table 16: Qualifying Facility Avoided Cost Rates for Transmission Connected Projects, without Line Losses ($/MWh)

	QF All-In Avoided Cost Rates (without line losses for transmission connected projects)	
Technology	**2-Year PPA**	**2024/2025 Avoided Cost Rate**
Solar: Single-Axis Tracking	29.05	42.22
Solar: Fixed Tilt	29.33	44.95
Wind	27.94	39.19
Other Technologies	28.05	38.53

Table 17 contains the Companies' assumptions for line losses used to calculate QF rates with line losses.

Table 17: Line Losses

	KU	LG&E
Energy Losses	4.748%	2.772%
Capacity Losses	6.449%	4.139%

Table 18: Qualifying Facility Avoided Energy Rates by Company, with Line Losses ($/MWh)

Technology	QF Avoided Energy, KU (with line losses)			QF Avoided Energy, LG&E (with line losses)		
	2-Year PPA	7-Year PPA Beginning:		2-Year PPA	7-Year PPA Beginning:	
		2024	2025		2024	2025
Solar: Single-Axis Tracking	30.43	31.96	32.36	29.86	31.36	31.75
Solar: Fixed Tilt	30.73	32.35	32.76	30.15	31.74	32.15
Wind	29.27	31.32	31.77	28.72	30.72	31.17
Other Technologies	29.39	31.71	32.20	28.83	31.11	31.59

Table 19: Qualifying Facility Avoided Capacity Rates by Company, with Line Losses ($/MWh)

Technology	QF Avoided Capacity, 2032 Need, KU (with line losses)			QF Avoided Capacity, 2032 Need, LG&E (with line losses)		
	2-Year PPA	7-Year PPA Beginning:		2-Year PPA	7-Year PPA Beginning:	
		2024	2025		2024	2025
Solar: Single-Axis Tracking	0.00	11.52	12.99	0.00	11.27	12.71
Solar: Fixed Tilt	0.00	13.87	15.65	0.00	13.57	15.31
Wind	0.00	9.08	10.25	0.00	8.89	10.03
Other Technologies	0.00	8.03	9.06	0.00	7.86	8.87

Table 20: Qualifying Facility All-In Avoided Cost Rates for 2-Year and 7-Year PPAs by Company, with Line Losses ($/MWh)

	QF All-In Avoided Cost Rate, KU		QF All-In Avoided Cost Rate, LG&E	
	2-Year PPA	2024/2025 Avoided Cost Rate	2-Year PPA	2024/2025 Avoided Cost Rate
Solar: Single-Axis Tracking	30.43	44.42	29.86	43.55
Solar: Fixed Tilt	30.73	47.32	30.15	46.38
Wind	29.27	41.21	28.72	40.40
Other Technologies	29.39	40.50	28.83	39.71

Because solar and wind resources are not fully available during the summer peak, the maximum amount of nameplate capacity eligible for an avoided capacity payment is computed by dividing the average summer capacity need in Table 4 by the QF resource's average summer availability in Table 7. For single-axis tracking solar, this quotient is 1,214 MW.[13] However, consistent with Case Nos. 2020-00349 and 2020-00350, the Companies continue to recommend limiting QF capacity to the lower of the actual need or 1,000 MW. The Levelized Cost of a CT methodology results in avoided cost rates for solar that are greater than the market price of solar, and these rates do not include revenues for renewable energy certificates that a QF may receive. Like the capacity limits in the Companies' Green Tariff Option #3, the 1,000 MW limit will provide an intermittent generation "circuit breaker" for assessing grid reliability in a scenario where a large amount of QFs are constructed in the Companies' service territories.

[13] 1,214 MW is 954 MW (average 2032 summer capacity need in Table 4) divided by 78.6% (average summer availability for single-axis tracking solar in Table 7).

6 NMS-2 Bill Credit

In accordance with the Commission's Orders in the Companies' 2020 base rate cases (Case Nos. 2020-00349 and 2020-00350), the Companies' Rider Net Metering Service-2 ("NMS-2") bill credits consist of eight components, as reflected in Table 21 below. In those cases, the Commission based the energy and generation capacity components of the Companies' NMS-2 bill credits on QF rates for the fixed tilt solar technology. The Companies therefore propose to update those two components of the NMS-2 bill credits using the updated QF rates presented here; updating the other components would require significantly more data and evaluation, which could be better and more comprehensively addressed in rate case proceedings. Therefore, consistent with the Commission's approach in Case Nos. 2020-00349 and 2020-00350, the Companies computed the energy and generation capacity components shown in Table 21 below as the average of the 7-year PPA prices (with line losses) for fixed-tilt solar PPAs beginning in 2024 and 2025 (see Table 18 and Table 19).[14]

Table 21: NMS-2 Bill Credits ($/kWh)

LG&E NMS-2 Bill Credit	
Energy*	0.03194
Ancillary Services	0.00082
Generation Capacity*	0.01444
Transmission Capacity	0.00732
Distribution Capacity	0.00129
Carbon Cost	0.01338
Environmental Compliance Cost	0.00105
Jobs Benefit	-
NMS-2 Bill Credit for Excess Gen	**0.07024**
*With losses	
KU NMS-2 Bill Credit	
Energy*	0.03256
Ancillary Services	0.00084
Generation Capacity*	0.01476
Transmission Capacity	0.00732
Distribution Capacity	0.00185
Carbon Cost	0.01338
Environmental Compliance Cost	0.00397
Jobs Benefit	-
NMS-2 Bill Credit for Excess Gen	**0.07468**
*With losses	

[14] For example, the energy component of LG&E's NMS-2 bill credit ($0.03194/kWh) is the average of the 7-year QF PPA prices in Table 18 for fixed-tilt solar PPAs beginning in 2024 ($31.74/MWh or $0.03174/kWh) and 2025 ($32.15/MWh or $0.03215/kWh). Furthermore, the sum of the energy and generation capacity components is equal to the QF all-in avoided cost rate for fixed-tilt solar ($46.38/MWh or $0.04638/kWh) in Table 20.

7 Appendix A

Table 22: 17% Summer Reserve Margin Need (MW)

	2024	2026	2028	2032	2034	2036	2040	2044
Peak Load	**6,206**	**6,286**	**6,355**	**6,316**	**6,301**	**6,297**	**6,289**	**6,282**
Dispatchable Generation Resources								
Existing Resources	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612
New NGCCs	0	0	1,242	1,242	1,242	1,242	1,242	1,242
Intermittent/Limited-Duration Resources								
Existing Resources	105	105	105	105	105	105	105	105
Existing CSR	128	128	128	128	128	128	128	128
Existing Dispatchable DSM[15]	60	52	46	38	35	32	28	26
New Solar[16]	0	681	866	866	866	866	866	866
New Battery Storage	0	125	125	125	125	125	125	125
New Dispatchable DSM[15]	14	44	102	127	127	127	127	127
Total Resources Before Ret.	**7,918**	**8,748**	**10,227**	**10,243**	**10,240**	**10,238**	**10,234**	**10,231**
Retirements								
Scenario 1: End of Depreciable Lives								
Small CTs	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)
Coal[17]	(300)	(300)	(1,494)	(1,494)	(1,969)	(1,969)	(3,796)	(3,796)
Large CTs	0	0	0	0	(121)	(484)	(776)	(2,007)
OVEC	0	0	0	0	0	0	(152)	(152)
Hydro	0	0	0	0	0	0	0	(32)
Total Cumulative Ret.	(300)	(347)	(1,541)	(1,541)	(2,137)	(2,500)	(4,771)	(6,034)
Resources Net of Ret.	7,618	8,401	8,686	8,702	8,103	7,738	5,463	4,198
Reserve Margin Need	**0**	**0**	**0**	**0**	**0**	**0**	**1,895**	**3,152**
Scenario 2: Section 111 (d)								
Small CTs	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)
Coal[17]	(300)	(300)	(1,494)	(4,715)	(4,715)	(4,715)	(4,715)	(4,715)
Large CTs	0	0	0	0	(121)	(484)	(776)	(2,007)
OVEC	0	0	0	0	0	0	(152)	(152)
Hydro	0	0	0	0	0	0	0	(32)
Total Cumulative Ret.	(300)	(347)	(1,541)	(4,762)	(4,883)	(5,246)	(5,690)	(6,952)
Resources Net of Ret.	7,618	8,401	8,686	5,481	5,357	4,992	4,544	3,279
Reserve Margin Need	**0**	**0**	**0**	**1,908**	**2,014**	**2,375**	**2,814**	**4,071**

[15] Dispatchable DSM reflects expected load reductions under normal peak weather conditions.
[16] Solar capacity values reflect 78.6% expected contribution to summer peak capacity.
[17] Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024, after which Mill Creek 1 is assumed to be retired.

Table 23: 24% Winter Reserve Margin Need (MW)

	2024	2026	2028	2032	2034	2036	2040	2044
Peak Load	**5,957**	**6,052**	**6,154**	**6,142**	**6,143**	**6,143**	**6,146**	**6,154**
Dispatchable Generation Resources								
Existing Resources	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909
New NGCCs	0	0	1,282	1,282	1,282	1,282	1,282	1,282
Intermittent/Limited-Duration Resources								
Existing Resources	72	72	72	72	72	72	72	72
Existing CSR	128	128	128	128	128	128	128	128
Existing Dispatchable DSM[15]	22	22	22	22	22	22	22	22
New Solar[18]	0	0	0	0	0	0	0	0
New Battery Storage	0	125	125	125	125	125	125	125
New Dispatchable DSM[15]	13	40	89	104	104	104	104	104
Total Resources Before Ret.	**8,143**	**8,294**	**9,626**	**9,641**	**9,641**	**9,641**	**9,641**	**9,641**
Retirements								
Scenario 1: End of Depreciable Lives								
Small CTs	0	(55)	(55)	(55)	(55)	(55)	(55)	(55)
Coal	0	(300)	(1,499)	(1,499)	(1,978)	(1,978)	(3,812)	(3,812)
Large CTs	0	0	0	0	(138)	(532)	(874)	(2,253)
OVEC	0	0	0	0	0	0	(158)	(158)
Hydro	0	0	0	0	0	0	0	(32)
Total Cumulative Ret.	0	(355)	(1,554)	(1,554)	(2,171)	(2,565)	(4,899)	(6,310)
Resources Net of Ret.	8,143	7,939	8,072	8,087	7,470	7,076	4,742	3,331
Reserve Margin Need	**0**	**0**	**0**	**0**	**147**	**542**	**2,879**	**4,299**
Scenario 2: Section 111 (d)								
Small CTs	0	(55)	(55)	(55)	(55)	(55)	(55)	(55)
Coal	0	(300)	(1,499)	(4,752)	(4,752)	(4,752)	(4,752)	(4,752)
Large CTs	0	0	0	0	(138)	(532)	(874)	(2,253)
OVEC	0	0	0	0	0	0	(158)	(158)
Hydro	0	0	0	0	0	0	0	(32)
Total Cumulative Ret.	0	(355)	(1,554)	(4,807)	(4,945)	(5,339)	(5,839)	(7,250)
Resources Net of Ret.	8,143	7,939	8,072	4,834	4,696	4,302	3,802	2,391
Reserve Margin Need	**0**	**0**	**0**	**2,783**	**2,921**	**3,315**	**3,819**	**5,239**

[18] Solar capacity values reflect 0% expected contribution to winter peak capacity.

Generation
Forecast Process

PPL companies

Generation Planning & Analysis
2023

Table of Contents

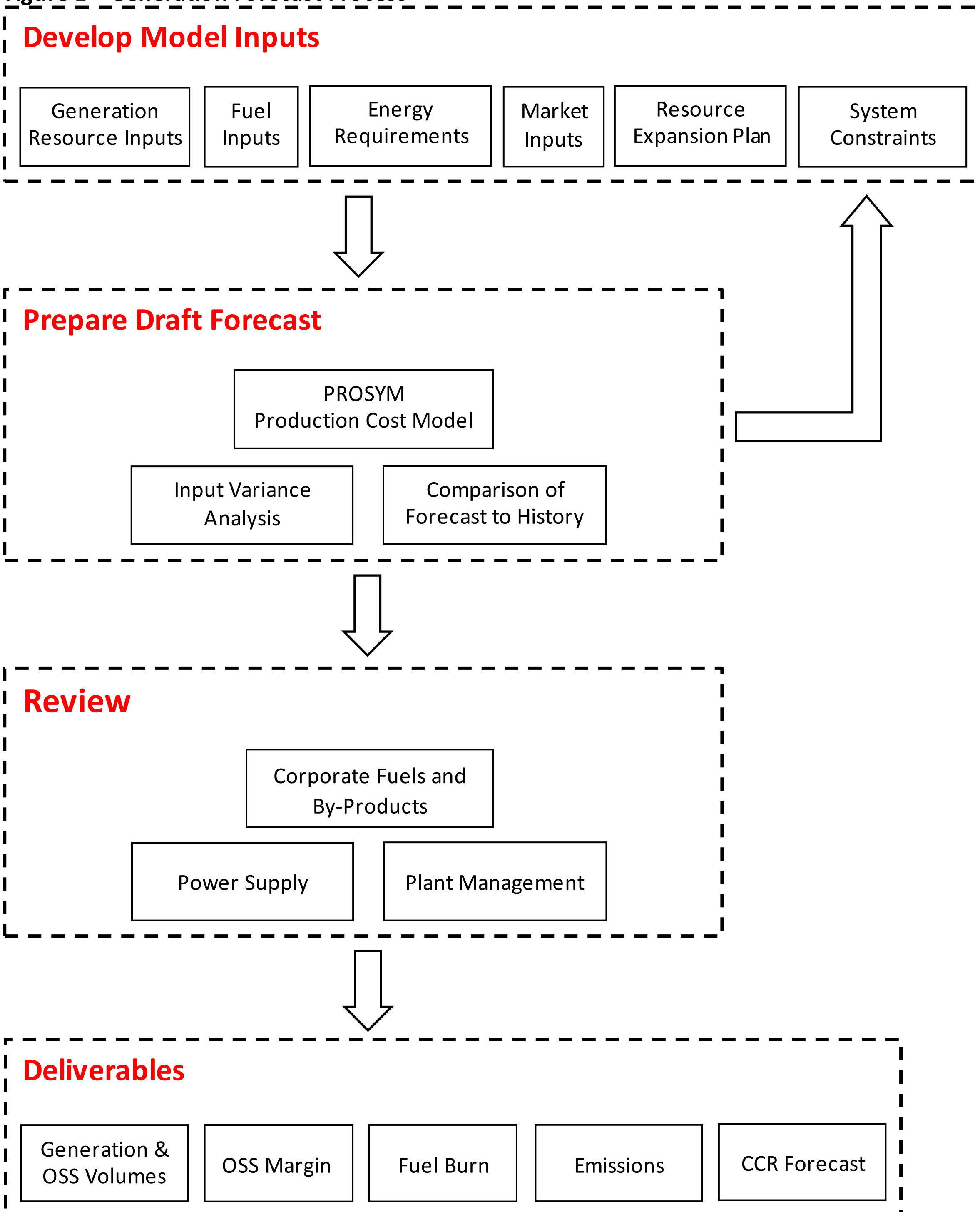
1 Introduction
The Generation Planning group annually prepares a generation and off-system sales ("OSS") forecast for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). This forecast provides the basis for – among other things – the Companies' 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 PROYSM 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.

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[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 forecasts 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

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[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, Group 3 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 effectively modeled in PROSYM, limits on hourly OSS and economy purchases are used to align the volume of modeled OSS and economy purchase transactions with recent historical experience.

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.

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[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 of 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

The attachment is being provided in a separate file in Excel format.

The attachment is being provided in a separate file in Excel format.

The attachment is being provided in a separate zipped folder.

The attachment is being provided in a separate zipped folder.

Kentucky Utilities Company

P.S.C. No. 20, Second Revision of Original Sheet No. 55
Canceling P.S.C. No. 20, First Revision of Original Sheet No. 55

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

APPLICABLE
In all territory served.

AVAILABILITY
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.

DEFINITIONS
"As-available" describes energy purchases from Seller when Seller has not entered into a PPA with Company.

"Other Technologies" means all electric power generating technologies encompassed in the definition of "qualifying facility" in 807 KAR 5:054 Section 1(8) other than solar and wind.

RATES FOR PURCHASES FROM SELLER UNDER PPA

Energy Rates ($/MWh)

	Distribution Connected Projects		Transmission Connected Projects	
Technology	**2-Year PPA**	**7-Year PPA**	**2-Year PPA**	**7-Year PPA**
Solar: Single-Axis Tracking	30.43	32.16	29.05	30.71
Solar: Fixed Tilt	30.73	32.56	29.33	31.09
Wind	29.27	31.55	27.94	30.11
Other Technologies	29.39	31.96	28.05	30.50

DATE OF ISSUE: October 31, 2023

DATE EFFECTIVE: With Service Rendered
On and After January 1, 2024

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

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Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

RATES FOR PURCHASES FROM SELLER UNDER PPA (Continued)

Capacity Rates ($/MWh)

Technology	Distribution Connected Projects		Transmission Connected Projects		
	2-Year PPA	7-Year PPA	2-Year PPA	7-Year PPA	
Solar: Single-Axis Tracking	0	12.26	0	11.51	R/R
Solar: Fixed Tilt	0	14.76	0	13.86	R/R
Wind	0	9.66	0	9.08	R/R
Other Technologies	0	8.54	0	8.03	R/R

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The Energy and Capacity rates stated above will be combined to equal the All-In Rate for payment to Seller.

RATES FOR ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Rates for energy purchases from Seller on an as-available basis are based upon the applicable 2-year PPA.

PAYMENT

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

TERM OF CONTRACT

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.

PARALLEL OPERATION

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

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DATE OF ISSUE: October 31, 2023

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On and After January 1, 2024

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

Kentucky Utilities Company

P.S.C. No. 20, Second Revision of Original Sheet No. 56
Canceling P.S.C. No. 20, First Revision of Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY

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 greater than 100 kW.

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.

RATES HEREIN ARE ADVISORY

Pursuant to 807 KAR 5:054 Section 7(4), the rates set forth herein are solely the basis for negotiating final purchase rates with Seller.

DEFINITIONS

"As-available" describes energy purchases from Seller when Seller has not entered into a PPA with Company.

"Other Technologies" means all electric power generating technologies encompassed in the definition of "qualifying facility" in 807 KAR 5:054 Section 1(8) other than solar and wind.

RATES FOR PURCHASES FROM SELLER UNDER PPA

Energy Rates ($/MWh)

	Distribution Connected Projects		Transmission Connected Projects	
Technology	**2-Year PPA**	**7-Year PPA**	**2-Year PPA**	**7-Year PPA**
Solar: Single-Axis Tracking	30.43	32.16	29.05	30.71
Solar: Fixed Tilt	30.73	32.56	29.33	31.09
Wind	29.27	31.55	27.94	30.11
Other Technologies	29.39	31.96	28.05	30.50

DATE OF ISSUE: October 31, 2023

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C No. 20, Second Revision of Original Sheet No. 56.1
Canceling P.S.C. No. 20, First Revision of Original Sheet No. 56.1

Standard Rate Rider LQF
Large Capacity Cogeneration and Small Power Production Qualifying Facilities

RATES FOR PURCHASES FROM SELLER UNDER PPA (Continued)

Capacity Rates ($/MWh)

Technology	Distribution Connected Projects		Transmission Connected Projects		
	2-Year PPA	7-Year PPA	2-Year PPA	7-Year PPA	
Solar: Single-Axis Tracking	0	12.26	0	11.51	R/R
Solar: Fixed Tilt	0	14.76	0	13.86	R/R
Wind	0	9.66	0	9.08	R/R
Other Technologies	0	8.54	0	8.03	R/R

The Energy and Capacity rates stated above will be combined to equal the All-In Rate for payment to Seller.

RATES FOR ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Rates for energy purchases from Seller on an as-available basis are based upon the applicable 2-year PPA.

PAYMENT

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

TERM OF CONTRACT

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.

PARALLEL OPERATION

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

DATE OF ISSUE: October 31, 2023

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On and After January 1, 2024

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

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Standard Rate Rider **NMS-2**

Net Metering Service-2

APPLICABLE

In all territory served.

AVAILABILITY

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.

BILLING

All Customer bills will be calculated in accordance with the Customer's standard rate schedule

ENERGY RATES & CREDITS

For each billing period, Company will net the dollar value of the total energy consumed and the dollar value of the total energy exported by Customer as follows: Company will (a) bill Customer for all energy consumed from Company in accordance with Customer's standard rate and (b) Company will provide a dollar-denominated bill credit for each kWh Customer produces to the Company's grid.

Dollar-denominated bill credit: $0.07468 per kWh I

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The dollar-denominated bill credit will be applied only to the energy charge and any riders that are based on a per kWh charge. Any bill credits not applied to a Customer's bill in a billing period are "unused excess billing-period credits." Any unused excess billing-period credits will be carried forward and drawn on by Customer as needed.

Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between Customers or locations. For joint accounts, unused excess billing-period credits will be carried forward as long as at least one joint account holder remains in the same location.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto. The Net Metering Service Interconnection Guidelines applicable to this Rider are at Sheet Nos. 108 *et seq.*

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CUSTOMER NOTICE OF RATE ADJUSTMENT

PLEASE TAKE NOTICE that, in a October 31, 2023, Tariff Filing, Kentucky Utilities Company ("KU") is seeking approval by the Kentucky Public Service Commission of an adjustment of its electric Small Capacity Cogeneration and Small Power Production Qualifying Facilities ("SQF"), Large Capacity Cogeneration and Large Power Production Qualifying Facilities ("LQF"), and Net Metering Service-2 ("NMS-2") rates and charges to become effective on and after January 1, 2024.

KU CURRENT AND PROPOSED SQF, LQF, and NMS-2 ELECTRIC RATES

SQF and LQF

Energy Rates ($/MWh)

Distribution Connected Projects

Technology	**2-Year PPA**				**7-Year PPA**			
	Current	Proposed	Change		Current	Proposed	Change	
Solar: Single-Axis Tracking	24.03	30.43	6.40	27%	25.02	32.16	7.14	29%
Solar: Fixed Tilt	24.29	30.73	6.44	27%	25.26	32.56	7.30	29%
Wind	23.58	29.27	5.69	24%	24.90	31.55	6.65	27%
Other Technologies	23.08	29.39	6.31	27%	24.13	31.96	7.83	32%

Transmission Connected Projects

Technology	**2-Year PPA**				**7-Year PPA**			
	Current	Proposed	Change		Current	Proposed	Change	
Solar: Single-Axis Tracking	22.94	29.05	6.11	27%	23.89	30.71	6.82	29%
Solar: Fixed Tilt	23.19	29.33	6.14	26%	24.11	31.09	6.98	29%
Wind	22.51	27.94	5.43	24%	23.77	30.11	6.34	27%
Other Technologies	22.04	28.05	6.01	27%	23.03	30.50	7.47	32%

Capacity Rates ($/MWh)

Distribution Connected Projects

Technology	2-Year PPA				7-Year PPA			
	Current	Proposed	Change		Current	Proposed	Change	
Solar: Single-Axis Tracking	0	0	0.00	0%	17.51	12.26	-5.25	-30%
Solar: Fixed Tilt	0	0	0.00	0%	21.05	14.76	-6.29	-30%
Wind	0	0	0.00	0%	13.81	9.66	-4.15	-30%
Other Technologies	0	0	0.00	0%	12.21	8.54	-3.67	-30%

Transmission Connected Projects

Technology	**2-Year PPA**				**7-Year PPA**			
	Current	Proposed	Change		Current	Proposed	Change	
Solar: Single-Axis Tracking	0	0	0.00	0%	16.45	11.51	-4.94	-30%
Solar: Fixed Tilt	0	0	0.00	0%	19.78	13.86	-5.92	-30%
Wind	0	0	0.00	0%	12.97	9.08	-3.89	-30%
Other Technologies	0	0	0.00	0%	11.47	8.03	-3.44	-30%

NMS-2

	Current	Proposed	Change	
Dollar-Denominated Bill Credit ($/kWh)	0.07366	0.07468	0.00102	1.4%

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 mail to Kentucky Utilities Company, ATTN: Rates Department, 220 West Main Street, Louisville, Kentucky, 40202, or by visiting KU's website at www.lge-ku.com/our-company/regulatory.

A person may examine this tariff filing at the offices of KU located at One Quality Street, Lexington, Kentucky. A person may also examine this tariff filing at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the Commission's Web site at http://psc.ky.gov.

Comments regarding the filing 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.

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 tariff filing.