COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, 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**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS 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. 2020-00350**

SUPPLEMENTAL DIRECT TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: July 13, 2021

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I. INTRODUCTION AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) describe the regulatory framework concerning compensation for qualifying facilities ("QFs") under 807 KAR 5:054 and relevant Commission precedents; (2) address the jobs benefit component of the Commission's new net metering compensation formula; and (3) describe Supplemental Exhibits RMC-1 through RMC-6, which are illustrative tariff sheets that reflect the proposals in Companies' supplemental testimony regarding Riders NMS-2, SQF, and LQF.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

Supplemental Exhibit RMC-1	Illustrative KU Rider NMS-2
Supplemental Exhibit RMC-2	Illustrative LG&E Rider NMS-2
Supplemental Exhibit RMC-3	Illustrative KU Rider SQF
Supplemental Exhibit RMC-4	Illustrative LG&E Rider SQF
Supplemental Exhibit RMC-5	Illustrative KU Rider LQF
Supplemental Exhibit RMC-6	Illustrative LG&E Rider LQF

II. QUALIFYING FACILITIES

Q. Are there particular provisions of 807 KAR 5:054, the Commission's regulation on qualifying facilities, you would highlight for the Commission's consideration?

A. Yes. Although the testimonies of David S. Sinclair and W. Steven Seelye address the QF-related items explicitly mentioned in the Commission's June 30, 2021 orders in these proceedings, I believe it is helpful to consider certain provisions of 807 KAR 5:054 when considering these matters.

First, as a general matter, 807 KAR 5:054 addresses itself only to avoided electric energy and generating capacity costs, not to other potentially avoided costs. For example, 807 KAR 5:054 Section 1(1) 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." In addition, I am not aware of any instance of including non-energy or non-generating capacity components in QF rates approved by this Commission over the nearly 40 years that 807 KAR 5:054 has governed QF rates in Kentucky.

Second, 807 KAR 5:054 has a pervasive focus on protecting utility customers by ensuring that purchases from QFs are financially beneficial to utility customers. For instance, 807 KAR 5:054 Section 6(2) curtails a QFs right to sell power to a utility when purchasing from the QF "will result in costs greater than those which the utility would incur if it generated an equivalent amount of energy instead of purchasing that energy." Similarly, the regulation requires that rates for purchases from QFs, both large and small QFs, are "just and reasonable to the electric customer of the utility, in the public interest, and nondiscriminatory."[1] Therefore, although it is certainly true that the Commission's QF regulation is intended to protect QFs, it has an equal and undeniable purpose to protect all customers.

Third, the Commission's QF regulation provides a set of criteria to consider when setting rates for purchases from QFs. Included in that list are the QF's "ability to dispatch, reliability, terms of contract, duration of obligation, termination requirements, ability to coordinate scheduled outages, [and] usefulness of energy and capacity during system emergencies …."[2] Different kinds of QFs will have significantly different characteristics with regard to each of these and the other criteria listed in the Commission's regulation. In other words, solar capacity is not directly comparable to wind capacity, just as wind capacity is not directly comparable to cogeneration facilities; each has unique characteristics and value to utilities and their customers, particularly with regard to capacity value and function. Therefore, the only reasonable approach to setting QF capacity rates would be to compare like facilities and their capacity values and costs.

Fourth and finally, the QF regulation makes an important distinction between tariffs for small QFs (100 kW or less) and large QFs (larger than 100 kW), namely that the tariff rates for small QFs are essentially prescriptive, whereas the tariff rates for large QFs are "only … the basis for negotiating a final purchase rate with qualifying facilities …."[3] This does not detract in any way from the importance of carefully crafting tariff provisions applicable to large QFs, but it does recognize that there is

[1] 807 KAR 5:054 Section 7(2) and (4).
[2] 807 KAR 5:054 Section 7(5)(a).
[3] 807 KAR 5:054 Section 7(4).

greater flexibility in how utilities and large QFs can arrive at arrangements that are mutually beneficial, particularly for customers. Thus, large QF tariff provisions do not need to anticipate and resolve every future situation or contingency, but rather need only provide a basic framework from which to negotiate.

In contrast to the limiting principles embedded in the QF regulation, the methodology approved in the Kentucky Power case and now proposed in this case for determining avoided cost has no such boundaries. Under the present proposal, there are eight components, but there are no controls, or checks and balances on adding additional components. Thus, the possibility of adding greater and greater amounts of cost is unlimited. This is a fundamental flaw that cannot be cured.

III. JOB BENEFITS COMPONENT OF NET METERING

Q. The Commission has advised the parties to these proceedings to "submit supplemental testimony related to … job benefits as they relate to calculating the NMS-2 export compensation rates."[4] What is the Companies' position regarding such a component of their NMS-2 export compensation rates?

A. The Companies respectfully state that such a "job benefits" component of a net metering compensation rate would be outside the Commission's jurisdiction, and the Commission therefore must reject it. The Commission's jurisdiction is limited to the rates and service of utilities;[5] it does not extend to job creation benefits per se, which

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[4] Case No. 2020-00349, Order at 37 (June 30, 2021); Case No. 2020-00350, Order at 39-40 (June 30, 2021).

[5] KRS 278.040(2). *See, e.g., EnviroPower, LLC v. Public Service Commission of Kentucky*, 2007 WL 289328 at *4 (Ky. App. 2007) (not to be published) ("First, there is the statutory limitation under KRS 278.040(2) that the person seeking intervention must have an interest in the "rates" or "service" of a utility, since those are the only two subjects under the jurisdiction of the PSC.").

are properly addressed by Kentucky's Cabinet for Economic Development, among other agencies.[6] Therefore, the Commission cannot include a job benefits component in the Companies' NMS-2 export compensation rates.

Indeed, the Commission's own orders have repeatedly and clearly rejected invitations to consider in ratemaking factors that do not directly affect utility rates or service. For example, in the Companies' 2017 Demand-Side Management and Energy Efficiency ("DSM-EE") Plan proceeding, Metropolitan Housing Coalition ("MHC") "request[ed] that avoided costs, specifically costs associated with greenhouse gas emission regulation and non-energy benefits, should be included in the benefit-cost analysis before any DSM/EE programs are curtailed or eliminated."[7] MHC asserted that "non-energy benefits are within the jurisdiction of the Commission and consideration of such benefits is essential in determining cost-effectiveness of the continuation of DSM/EE measures."[8] The Commission flatly and unequivocally rejected MHC's position:

> KRS Chapter 278 creates the Commission as a statutory administrative agency empowered with "exclusive jurisdiction over the regulation of rates and service of utilities." *The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service. Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost analyses of DSM programs.* As LG&E/KU correctly note, it does not follow from their citing in 2014 of the potential avoidance of environmental compliance costs in rates in support of the construction of a 10 MW solar facility that the

[6] In the Companies' 2008 Integrated Resource Plan proceeding, the Commission denied a petition to intervene because the petitioner's stated concerns were environmental rather than related to rates or service. The Commission noted that environmental concerns were under the jurisdiction of other state agencies, not the Commission: "Notably absent from the Commission's jurisdiction are environmental concerns, which are the responsibility of other agencies within Kentucky state government." *The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2008-00148, Order at 5-6 (PSC Ky. July 18, 2008).

[7] Case No. 2017-00441, Order at 24 (Oct. 5, 2018).

[8] *Id*.

> Commission has jurisdiction in a DSM case to require an analysis of non-energy criteria such as environmental and health factors that have no impact on rates.[9]

In other words, the Commission clearly stated that it "has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service," and it therefore refused to consider non-jurisdictional costs and benefits to evaluate the cost-effectiveness of DSM-EE programs, programs over which the Commission clearly did have jurisdiction.

The Commission has likewise denied petitions to intervene in non-DSM-EE cases when the petitioners expressed environmental or health concerns rather than concerns directly impacting utility rates or service because the Commission lacked jurisdiction over the petitioners' stated interests.[10]

The Companies therefore respectfully submit that adding a jobs-related component to the Companies' NMS-2 compensation rates would be impermissible because job creation is not within the Commission's jurisdiction.

Q. If job creation benefits are outside the Commission's jurisdiction, what supports the Companies' and other utilities' economic development riders ("EDRs")?

A. There is clear Kentucky law supporting the lawfulness of EDRs generally. The Kentucky Supreme Court held in a 2010 case involving Duke Energy Kentucky:

> Simply stated, EDRs generally are lawful under KRS 278.170(1) and KRS 278.030 and a particular EDR is sustainable provided the PSC

[9] *Id.* at 28-29 (emphasis added; internal citation to KRS 278.040(2)).

[10] *See, e.g., The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Order at 4 (Ky. PSC July 8, 2011) ("[I]ssues of environmental externalities, such as air and water pollution from generating electricity and mining fuel to supply the generating plants, are all issues beyond the scope of the Commission's jurisdiction."); *The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2008-00148, Order at 5-6 (PSC Ky. July 18, 2008).

> determines that the rate is reasonable and that determination withstands the appropriate scrutiny on judicial review.[11]

Duke Kentucky's EDR required (and still requires) minimum levels of jobs created and capital investment per 1,000 kW of new load that can qualify for an EDR special contract.[12] Although the Kentucky Supreme Court explicitly did not rule on the reasonableness of Duke Kentucky's particular EDR and did not address the issue of the Commission's jurisdiction under KRS 278.040,[13] it is noteworthy that Duke Kentucky's EDR tariff provisions did not and do not tie any economic development rate to a quantification of benefits related to jobs required to be created or capital to be invested; rather, the minimum jobs and capital investment requirements are criteria to qualify for EDRs, not to determine the rate-related terms of the EDR contract.

The Commission's foundational orders concerning economic development rates, as well as the Companies' Economic Development Riders ("EDRs") themselves, similarly do not require any level of job creation benefit or benefit from capital investment by EDR customers; rather they require documentation of job creation and capital investment related to customers who take service under such rates.

The Commission's first order articulating a clear set of requirements for economic development rates stated:

> Each utility that offers an economic development rate should be required to *document and report* any increase in employment and capital

[11] *Public Service Comm'n of Ky. v. Commonwealth of Kentucky, et al.*, 320 S.W.3d 660, 668 (Ky. 2010).
[12] *Id.* at 663-64; Duke Energy Kentucky, Inc., KY.P.S.C. Electric No. 2, Third Revised Sheet No. 86.
[13] *Public Service Comm'n of Ky. v. Commonwealth of Kentucky, et al.*, 320 S.W.3d 660, 669 (Ky. 2010) ("Thus, while reasonableness of the Duke Energy Kentucky EDRs would ordinarily be our next focus, this issue is not properly before us, there being neither evidence of record nor argument contesting the specifics of the Development Incentive Rider or the Brownfield Redevelopment Rider.").

investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.[14]

Notably, the order does not require any demonstration of job creation or capital investment benefit or tie such a benefit to the rates customers may have under EDRs.

The Commission's second and most recent foundational order concerning EDRs revisited job creation and capital investment, stating that the issue was "whether specific job creation and capital investment levels necessary to qualify for EDRs should be established by the Commission, or whether these levels should merely be monitored by the Commission in order to assess the impact of EDRs on economic activity in the state."[15] Although the Commission did not address the question from a jurisdictional perspective, it determined not to impose a job creation or capital investment requirement, but rather required utilities with customers taking service under EDRs to report annually regarding job creation and capital investment resulting from such rates.[16] Again, the Commission did not attempt to quantify job creation or capital investment benefits, and it did not tie EDR rates to such benefits.

The Commission's historical avoidance of using job creation or capital investment benefits to set EDR rates is precisely what permits EDRs to be permissible under KRS 278.040(2) and the Commission's longstanding precedent concerning its own jurisdiction. Any attempt to set EDR rates—or net metering compensation rates—using purported economic benefits arising from job creation would exceed the Commission's jurisdiction and authority as the Commission itself has articulated it.

[14] *Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 10064, Order at 93 (Ky. PSC July 1, 1988) (emphasis added).
[15] *An Investigation into the Implementation of Economic Development Rates by Electric and Gas Utilities*, Admin. Case No. 327, Order at 10 (PSC Ky. Sept. 24, 1990).
[16] *Id.* at 12.

This is precisely because the rates-and-service basis for EDRs has no direct relationship to job creation or capital investment economic benefits per se, but rather to retaining or increasing utility load when it would be beneficial to existing customers by spreading fixed-cost recovery over additional customers and load. In other words, the Companies do not provide EDRs because they create jobs; rather, job creation is a byproduct of economic development that increases load and improves rates (at least relatively). That is why EDRs are within the Commission's jurisdiction to approve; they have a direct connection to utility rates and service.

In addition, the Commission has consistently required that EDRs first do no harm to other customers by ensuring that customers taking service under such rates pay at least their marginal cost of service—including any additional fixed costs required to serve them—and make some contribution to fixed-cost recovery that would benefit other customers.[17] Moreover, the Commission has always required that EDRs be limited in duration; the goal is to have all load served at standard tariffed rates.

All of this stands in stark contrast to net metering. Net metering reduces customers' energy consumed from utilities, necessitating increased fixed-cost recovery from other customers, at least in the short run (i.e., before the claimed long-run capacity savings of net metering materialize). In addition, EDRs are the only means of compensating participating customers for helping reduce costs to other customers by increasing or retaining load. Under the first seven components of the Commission's new net metering export compensation approach, new net metering customers will be fully compensated for all costs they avoid, so they do not require a "jobs creation

[17] *See, e.g., id.* at 7-8, 10; Case No. 10064, Order at 93-94 (Ky. PSC July 1, 1988).

benefit" component to ensure they are compensated for utility-rate-related value. And unlike the Companies' EDRs, which provide demand-rate discounts for only five years, net metering rates can go on indefinitely. Customers certainly have the right to serve their own electric needs, but it is difficult to conceive of two less comparable categories of tariff provisions than EDRs and net metering.

In summary, economic development rates are permissible only because they have direct impacts on utility rates, not because they might result in job creation or capital investment benefits. They therefore provide no basis or justification for adding a job-creation benefit component to net metering export rate compensation, which would be entirely outside the Commission's jurisdiction and beyond its authority.

IV. ILLUSTRATIVE RIDERS NMS-2, SQF, AND LQF

Q. What changes to the Companies' proposed NMS-2 tariff sheets would be needed to implement the NMS-2 approach described in the Companies' supplemental testimony?

A. As shown in the illustrative tariff sheets in Supplemental Exhibits RMC-1 (KU) and RMC-2 (LG&E), implementing the NMS-2 approach would require deleting the sentence in the "Energy Rates and Credits" section that ties NMS-2 compensation to Rider SQF and replacing it with a statement of the dollar-denominated credit per kWh of energy produced to the Companies' grid. The credit per kWh would remain fixed until the Companies' next base rate cases. The illustrative tariff sheets also reflect a clarification that NMS-2 compensation rates apply to all energy NMS-2 customers supply to the Companies' grid, not to all energy produced by NMS-2 customers.

Q. What changes to the Companies' SQF tariff sheets would be needed to implement the SQF approach described in the Companies' supplemental testimony?

A. As shown in the illustrative tariff sheets in Supplemental Exhibits RMC-3 (KU) and RMC-4 (LG&E), implementing the SQF approach described in the Companies' supplemental testimony begins with removing references to Rates A and B and related references to rate selection and time-differentiated rates. The illustrative tariff sheets replace those provisions with energy-only rates for as-available energy providers, as well as energy and capacity rates for SQFs with two-year contracts and for those with 20-year contracts. Each set of energy and capacity rates is divided into rates based on the SQF's generating technology, again as described in Mr. Sinclair's supplemental testimony. These energy and capacity rates would be updated biennially using the same procedures currently in place to update SQF rates based on updated avoided cost information.

In addition, the capacity rate provisions reflect the differing value of additional capacity to meet anticipated needs at different times, as well as a provision to set the capacity rate to zero when 1,000 MW of nameplate QF (SQF plus LQF) capacity is contracted across both Companies. The Companies propose to update the level at which new QF capacity rates become zero with each biennial avoided cost update filing as anticipated capacity needs change over time.

The only other substantive addition to the SQF tariff sheets would be a Term of Contract provision, which describes the two-year and twenty-year contract options for SQFs.

Q. Will any other tariff changes be necessary if the Commission approves the Companies' proposed SQF changes?

A. Yes. The Solar Share Program Rider currently states in the Solar Energy Credit section, "If production equaled or exceeded consumption in any relevant period, Company will bill Customer for zero energy consumption for that period and provide a bill credit for each kWh of net production, if any, *at the then-applicable non-time-differentiated rate for Company's Standard Rate Rider SQF*."[18] Because the SQF non-time-differentiated rate would no longer exist under the Companies' proposal, the quoted sentence would be revised as follows: "If production equaled or exceeded consumption in any relevant period, Company will bill Customer for zero energy consumption for that period and provide a bill credit for each kWh of net production, if any, at the then-applicable Solar: Fixed Tilt rate for energy purchases on an as-available basis under the Company's Standard Rate Rider SQF."

Q. What changes to the Companies' LQF tariff sheets would be needed to implement the LQF approach described in the Companies' supplemental testimony?

A. As shown in the illustrative tariff sheets in Supplemental Exhibits RMC-5 (KU) and RMC-6 (LG&E), implementing the LQF approach described in the Companies' supplemental testimony requires revising the LQF tariff sheets to be nearly identical to the SQF tariff sheets shown in Supplemental Exhibits RMC-3 (KU) and RMC-4 (LG&E). The only differences are that the illustrative LQF tariff sheets note the different capacity range to which LQF applies and that, unlike SQF, the LQF tariff provisions are only the starting point for LQF contract negotiations (as required by 807 KAR 5:054 Section 7(4)). Revising the Companies' existing LQF tariff provisions to largely mirror their proposed SQF tariff provisions will help increase administrative

[18] Emphasis added.

efficiency and reduce possible customer confusion, and would be consistent with the unified avoided cost approach proposed in Mr. Sinclair's testimony.

Q. Will any other tariff changes be necessary if the Commission approves the Companies' proposed LQF changes?

A. Yes. The Green Tariff Rider currently states in the Option #3: Renewable Power Agreement section in paragraph b, "Company will also provide Customer a bill credit for all Net Production in each billing period, with all Net Production *to be valued at the avoided energy cost calculated under Company's Standard Rate Rider LQF* (Sheet No. 56)."[19] Because LQF will be revised to provide avoided energy cost rates under the Companies' proposal rather than calculations, the quoted sentence would be revised as follows: "Company will also provide Customer a bill credit for all Net Production in each billing period, with all Net Production to be valued at the rate then applicable to Customer's chosen generation technology for energy purchases on an as-available basis under Company's Standard Rate Rider LQF (Sheet No. 56)."

Q. Given that the Companies are proposing new SQF and LQF rates in these proceedings, when would the Companies propose to make their next biennial QF avoided cost filings?

A. Because the new SQF and LQF rates from these proceedings are likely to go into effect near the end of September this year, the Companies propose to make their next biennial QF avoided cost filings by September 30, 2023, for updated SQF and LQF rates to go into effect on January 1, 2024. With the Commission's approval, this approach would be consistent with 807 KAR 5:054 Section 5(1)(a)'s requirements concerning updated

[19] Emphasis added.

avoided cost filings and would reduce administrative burdens for the Commission and the Companies; the Companies would otherwise have to make avoided cost filings less than a year after new SQF and LQF rates went into effect following these proceedings.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of July 2021.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

Kentucky Utilities Company

Standard Rate Rider **NMS-2** N

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 who executes Company's Application for Interconnection and Net Metering on or after September DD, 2021. The generation facility shall be limited to a maximum rated capacity of 45 kilowatts.

Company's Application for Interconnection and Net Metering is available online at https://lge-ku.com/residential/net-metering. Company will provide a paper application to Customer upon request.

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 (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: $0.02319 per kWh

Any bill credits greater than the Customer's total bill will be carried forward to future bills.

Unused credits existing at the time Customer's service is terminated, end with Customer's account, have no monetary value, and are not transferrable between locations.

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.*

DATE OF ISSUE:

DATE EFFECTIVE: With Service Rendered
On and After September DD, 2021

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00349 dated XXXX

Louisville Gas and Electric Company

Standard Rate Rider **NMS-2**

Net Metering Service-2

N

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 who executes Company's Application for Interconnection and Net Metering on or after September DD, 2021. The generation facility shall be limited to a maximum rated capacity of 45 kilowatts.

Company's Application for Interconnection and Net Metering is available online at https://lge-ku.com/residential/net-metering. Company will provide a paper application to Customer upon request.

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

Kentucky Utilities Company

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. D/N D/N D/N

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. D/N D/N

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-avilable basis. D/N D/N D/N

DEFINITIONS D/N

"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 ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Technology	$/MWh
Solar: Single-Axis Tracking	22.94
Solar: Fixed Tilt	23.19
Wind	22.51
Other Technologies	22.04

DATE OF ISSUE:

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On and After September DD, 2021

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00349 dated XXXX

Kentucky Utilities Company

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

D/N

RATES FOR PURCHASES FROM SELLER UNDER PPA

Energy Rates ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Capacity Rates ($/MWh)

Capacity Rates for First 109 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71

Capacity Rates for Next 891 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

When the total qualifying facility nameplate capacity contracted by Company and its sister utility, Louisville Gas and Electric Company, reaches 1,000 MW, the capacity rate for all subsequent qualifying facility contracts will be zero. This limitation will be reviewed and possibly revised as part of Company's biennial avoided cost filing review process with the Commission.

T/D

DATE OF ISSUE:

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

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Kentucky Utilities Company

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

PAYMENT T
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. T T T T T

TERM OF CONTRACT N
If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 20-year PPA with Company for such purchases. Regarding energy purchases under a 20-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 20-year level energy rate or (b) the applicable as-available energy rate in effect at the time of each purchase. N N N N N

PARALLEL OPERATION T
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: T T T

T

DATE OF ISSUE:

DATE EFFECTIVE: With Bills Rendered
On and After September DD, 2021

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00349 dated XXXX

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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

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

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

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

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

T

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

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

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

Louisville Gas and Electric Company

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. D/N D/N D/N

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. D/N D/N

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-avilable basis. D/N D/N D/N

DEFINITIONS D/N
"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 ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Technology	$/MWh
Solar: Single-Axis Tracking	22.94
Solar: Fixed Tilt	23.19
Wind	22.51
Other Technologies	22.04

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

Louisville Gas and Electric Company

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

D/N

RATES FOR PURCHASES FROM SELLER UNDER PPA

Energy Rates ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Capacity Rates ($/MWh)

Capacity Rates for First 109 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71

Capacity Rates for Next 891 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

When the total qualifying facility nameplate capacity contracted by Company and its sister utility, Louisville Gas and Electric Company, reaches 1,000 MW, the capacity rate for all subsequent qualifying facility contracts will be zero. This limitation will be reviewed and possibly revised as part of Company's biennial avoided cost filing review process with the Commission.

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than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, T
that, if Seller is a Customer of Company, in lieu of such payment Company may offset its payment T
due to Seller hereunder, against Seller's next bill and payment due to Company for Company's T
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TERM OF CONTRACT N
If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a N
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Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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

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6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

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

Kentucky Utilities Company

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. D/N

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-avilable 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 ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Technology	$/MWh
Solar: Single-Axis Tracking	22.94
Solar: Fixed Tilt	23.19
Wind	22.51
Other Technologies	22.04

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Lexington, Kentucky

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

RATES FOR PURCHASES FROM SELLER UNDER PPA D/N

Energy Rates ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Capacity Rates ($/MWh)

Capacity Rates for First 109 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71

Capacity Rates for Next 891 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
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Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

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Large Capacity Cogeneration and Small Power Production Qualifying Facilities

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. T T T T T

TERM OF CONTRACT T

If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 20-year PPA with Company for such purchases. Regarding energy purchases under a 20-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 20-year level energy rate or (b) the applicable as-available energy rate in effect at the time of each purchase.. D/N D/N D/N N N

PARALLEL OPERATION D/N

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

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

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

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PARALLEL OPERATION (Continued)

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

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

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a Customer of Company. When Seller is a Customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation, or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

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8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

Kentucky Utilities Company

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

N

PARALLEL OPERATION (Continued)

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
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Louisville Gas and Electric Company

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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. D/N

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-avilable 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 ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

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D/N

RATES FOR PURCHASES FROM SELLER UNDER PPA

Energy Rates ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Capacity Rates ($/MWh)

Capacity Rates for First 109 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71

Capacity Rates for Next 891 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

When the total qualifying facility nameplate capacity contracted by Company and its sister utility, Louisville Gas and Electric Company, reaches 1,000 MW, the capacity rate for all subsequent qualifying facility contracts will be zero. This limitation will be reviewed and possibly revised as part of Company's biennial avoided cost filing review process with the Commission.

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DATE OF ISSUE:

DATE EFFECTIVE: With Bills Rendered
On and After September DD, 2021

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

PAYMENT T
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. T T T T T

TERM OF CONTRACT T
If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 20-year PPA with Company for such purchases. Regarding energy purchases under a 20-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 20-year level energy rate or (b) the applicable as-available energy rate in effect at the time of each purchase.. D/N D/N D/N N N

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

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

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

Louisville Gas and Electric Company

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PARALLEL OPERATION (Continued)

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

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

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a Customer of Company. When Seller is a Customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation, or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

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On and After September DD, 2021

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

Louisville Gas and Electric Company

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

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PARALLEL OPERATION (Continued)

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

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

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

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, 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**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS 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. 2020-00350**

SUPPLEMENTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: July 13, 2021

Table of Contents

Exhibits

Supplemental Exhibit WSS-1 – Maximum Avoided Transmission Capacity Cost

Supplemental Exhibit WSS-2 – Maximum Avoided Distribution Capacity Cost

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. I am the Managing Partner of The Prime Group, LLC. The Prime Group's business address is 2604 Sunningdale Place East, La Grange, Kentucky 40031.

Q. Did you submit direct and rebuttal testimony in these proceedings?

A. Yes. I submitted direct testimony and rebuttal testimony on behalf of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies").

Q. Please describe the purpose of your supplemental testimony.

A. After providing a working definition of avoided cost, I will discuss the general methodologies for calculating utility avoided costs. Specifically, I will describe methodologies for determining (i) avoided energy cost, (ii) avoided ancillary service cost, (iii) avoided generation capacity cost, (iv) avoided transmission capacity cost, (v) avoided distribution capacity cost, (vi) avoided carbon cost, (vii) avoided environmental compliance costs, and (viii) job benefits as they relate to calculating the NMS-2 export compensation rates. I will also develop a range of cost estimates for these eight avoided cost components and benefits, reflecting the discussions of avoided costs in the supplemental testimonies of David S. Sinclair, Beth McFarland, John K. Wolfe, and Robert M. Conroy. Specifically, I recommend an NMS-2 compensation rate range of $0.02319 to $0.02677 per kWh for KU and a range of

$0.02319 to $0.02581 per kWh for LG&E.

II. PRINCIPLES FOR CALCULATING AVOIDED COSTS

Q. What is avoided cost?

A. The term *avoided cost* has the established definition: "the cost the utility would have incurred had it generated the electricity itself or purchased the electricity from another source."[1] Similarly, the Federal Energy Regulatory Commission's ("FERC's") regulations define *avoided cost* as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[2] The Commission's definition is substantively identical to FERC's.[3] Therefore, avoided cost is equivalent to a utility's marginal or decremental/incremental cost of serving customers. Thus, avoided cost represents the change in cost due to a change in demand or energy that a supply resource or demand-side management resource supplies to the grid. Mathematically, avoided cost corresponds to the first partial derivative of the utility's cost curve, represented as follows:

1 Amer. Paper Instit. v. AEP Svc. Corp., 461 U.S. 402, 404(1983)

2 18 CFR § 292.101

3 807 KAR 5:054 Sec. 1(1) ("'Avoided costs' means 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.").

$$Avoided\ Cost = \frac{\partial C}{\partial q}$$

Where C is the utility's cost structure (or cost function) and q is the quantity supplied. What this partial differential equation means in plain English is simply that avoided cost is equal to a change in costs with respect to a change in quantity.

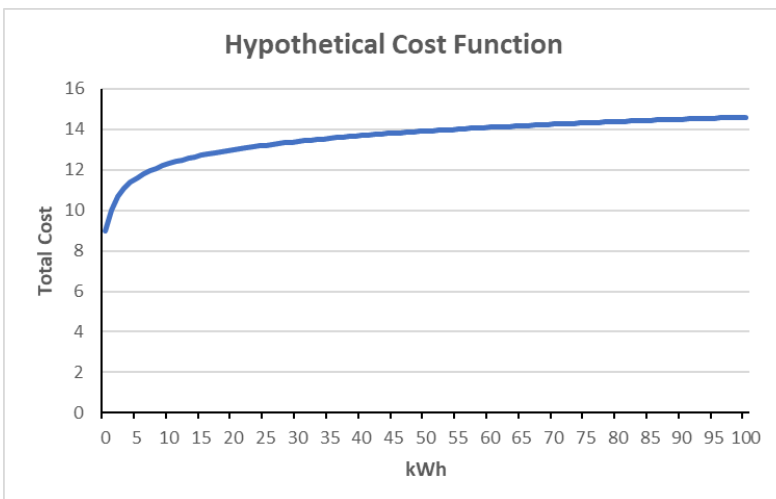
Q. Is avoided cost the same as embedded cost?

A. No. Avoided cost and embedded cost are entirely different concepts. Like apples and oranges, they cannot be compared. As used in the utility industry, embedded cost corresponds to the original cost of the installed utility plant less accumulated depreciation and associated contributions in aid of construction as recorded in the utility's accounting records. Embedded costs are the costs used to establish the service rates charged by utilities in Kentucky. Embedded costs represent the cost of plant that has been installed to meet customer needs. Fundamentally, embedded costs are retrospective while avoided costs are prospective. Embedded costs include the cost of plant that has been installed (past tense) to serve customers, whereas avoided costs represent costs that will be incurred (future tense) in the absence of the energy supplied to the grid by net metering customer or qualifying customer or in the absence of energy savings provided by demand-side management and energy efficiency technologies.

Q. Can embedded cost be used as a proxy for avoided cost?

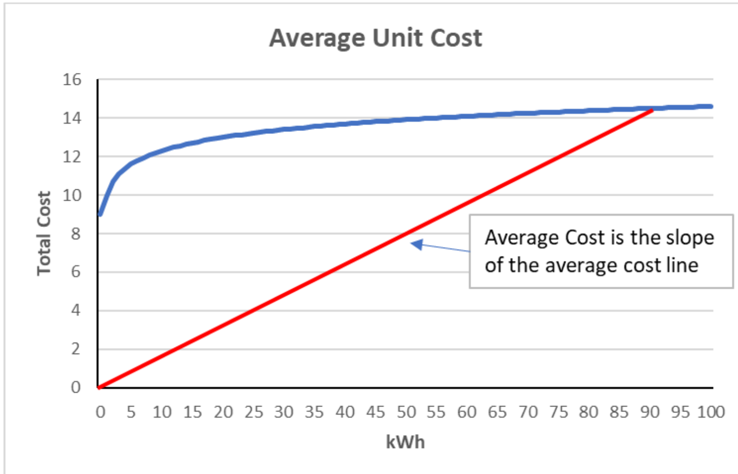
A. No. There is no relationship between the two. Just as apples cannot be substituted for oranges, embedded cost cannot be used as a proxy for, or an estimate of, avoided cost, nor can avoided cost be used as a proxy for or estimate of embedded costs. They are entirely different concepts; they measure different costs. Not only does embedded cost reflect a retrospective cost whereas avoided cost represents future cost, but embedded cost corresponds to an average cost whereas avoided cost corresponds to a marginal value. To illustrate how radically different an average unit cost can be compared to the avoided or marginal cost, consider the following cost function (GRAPH 1):

GRAPH 1



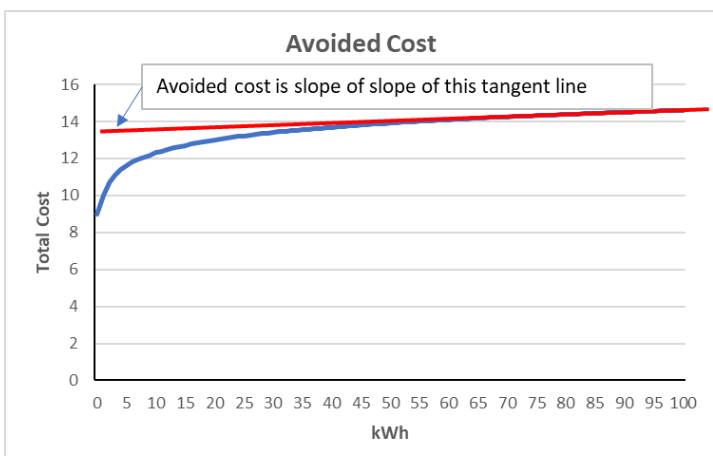
At 90 kWh, the total cost is $14.50 and the average cost per kWh for this cost function is $0.1611 per kWh, corresponding to the slope of the straight line superimposed on the graph of the cost function (GRAPH 2):

GRAPH 2



The avoided cost (marginal cost) at 90 kWh is only $0.0111 per kWh, which corresponds to the slope of the line tangent[4] to the cost function at 90 kWh, as shown in the following graph (GRAPH 3):

GRAPH 3



[4] Mathematically, the slope of the line tangent to the cost function is the first derivative of the cost function, which corresponds to the mathematical definition of avoided cost provided earlier.

This simple example illustrates the radical difference between average cost and avoided cost. In this example, the average unit cost of $0.1611 per kWh is over 14 times higher than the avoided cost of $0.0111 per kWh, demonstrating that a utility's average embedded cost cannot be used as a proxy for avoided cost.

Q. How are avoided capacity costs generally calculated?

A. The calculation of avoided capacity costs is closely tied to the utility's planning process. As explained above, avoided costs represent the change in cost due to a change in demand or energy that a supply resource or demand-side management resource supplies to the grid. In the case of a customer-generator served under a net metering tariff, avoided cost represents the change in a utility's current or future costs resulting from the energy or capacity that the customer-generator supplies to the grid. Implied by this definition is that there are both short-run marginal cost components and potentially long-run marginal cost components.

Short-run marginal cost components reflect the changes in costs due to changes in the energy supplied to the grid based on the assumption that the utility's capacity resources are fixed. Avoided energy costs are short-run marginal costs. They are calculated using production cost modeling. KU and LG&E have been using production cost modeling to calculate avoided energy costs of the Small Capacity Cogeneration and Small Power Production Qualifying Facilities (SQF) for approximately 40 years.

Long-run marginal cost components reflect the changes in costs due to changes in the power supplied to the grid and thus reflect the impacts that changes in demand can have on the utility's planned facilities. As mentioned earlier, unlike embedded costs, avoided costs deal with future costs. Therefore, a long-run marginal cost component of avoided costs would relate to the change in resources planned by the utility to meet future customer demands. In this way, avoided capacity costs relate to future resources and not existing or embedded resources.

Q. In its Orders dated June 30, 2021, in these proceedings, the Commission identified seven avoided cost components along with jobs benefits that should be considered in developing export compensation rates for net metering customers. Do you generally agree that the Commission has properly identified the categories of avoided costs that should be considered in developing export compensation rates for NMS-2?

A. Yes. The Commission identified seven categories of avoided costs that could be considered in determining the compensation for the energy that NMS-2 customers supply to the grid: (a) avoided energy cost, (b) avoided ancillary service cost, (c) avoided generation capacity cost, (d) avoided transmission capacity cost, (e) avoided distribution capacity cost, (f) avoided carbon cost, and (g) avoided environmental compliance costs. These seven categories represent reasonable types of avoided costs that could be considered with respect to export compensation rates under NMS-2 because they directly affect the cost to serve customers. But though the categories of avoided costs identified by the Commission are reasonable for the consideration as to avoided costs, the cost under any given category could be determined to have a value of zero. In other words, the energy supplied to the grid by a customer-generator could very well result in no avoided costs under a particular avoided cost category, or an analysis of avoided cost performed at one point in time could result in zero avoided capacity cost but the same analysis performed at some future date could result in a non-zero avoided cost due to changed circumstances. If a utility has sufficient or excess capacity, then additional energy supplied to the grid will result in no avoided capacity cost, at least if the expected energy to be supplied would not permit the utility to reduce the cost of future replacement capacity.

III. AVOIDED ENERGY COST

Q. Have the Companies developed an estimate of their avoided energy cost?

A. Yes. The Companies set forth their avoided energy cost in the SQF rate schedules. KU and LG&E's Schedule SQF was implemented pursuant to 807 KAR 5:054, which was promulgated as part Commission's review and consideration of provisions established in Section 210 of the Public Utilities Regulatory Policies Act ("PURPA"). Section 7(2)(a) of the Commission's regulations states, "Rates for power offered on an 'as available' basis shall be based on the purchasing utility's avoided energy costs at the time of delivery." The rates set forth in SQF are updated by KU and LG&E every two years. The Companies utilize a production cost model to calculate their avoided energy costs. In the model, production energy costs are calculated based on the energy costs of the Companies' generation resources reflecting the heat rate curves, availability factors, scheduled outages, fuel costs, variable operation and maintenance expenses, etc. for each resource. The same general approach has been consistently used by the Companies for approximately 40 years.

Q. Have the Companies updated their calculations of avoided energy costs?

A. Yes. The Companies are proposing a new framework for compensating qualifying facilities under LQF and SQF for the energy and capacity purchased by KU and LG&E. Mr. Sinclair discusses a revised calculation of avoided energy costs for LQF and SQF in his testimony. For Fixed-Tilt Solar, the avoided energy cost based on the average avoided energy cost for 2022 and 2023 is proposed to be $0.02319/kWh. Because the compensation for avoided energy costs under NMS-2 should be placed on an equal footing with the compensation for avoided energy costs under SQF and LQF, it is my recommendation that the avoided energy cost component for NMS-2 should be $0.02319/kWh. Nearly all customer-generators taking service under NMS-2 will most likely have Fixed-Tilt Solar installations.

Q. Should a line loss component be included in the avoided energy cost?

A. No. As I explained in my rebuttal testimony in these proceedings, determining avoided losses associated with power supplied to the grid by customer-generators is a very complex issue. Whether a customer generator adds to or decreases line losses on the system depends on a multitude of factors that are ultimately affected by customer-specific and locational considerations. As I also explained in my rebuttal testimony, distributed generation will not avoid "core losses" in transformers, which are unaffected by current flows.[5] A significant portion of losses on any transmission and

[5] Core losses include hysteresis and eddy current losses in transformers. These losses are considered fixed.

distribution system relate to core losses. Furthermore, because it is always necessary for any energy that a customer-generator supplies to the grid to be transmitted across the distribution system, resistive (I^2R) losses are always involved in the delivery of energy from a customer-generator and will thus never be entirely avoided by the purchase of energy from the customer-generator.[6] Therefore, at most it is only reasonable to assume that customer-generators could avoid variable transmission losses (i.e., non-core losses) and *a portion of* non-core losses on the primary voltage system.[7] Because it is always necessary for any energy that a residential customer-generator supplies to the grid to be transmitted across the secondary distribution system, losses related to the secondary distribution system should not be included as avoided costs.

Q. If the Commission determines that a line loss factor should be included, have you developed estimates of the maximum line losses that should be included as avoided energy costs?

A. Yes. Again, it is important to recognize that the actual amount of distribution losses realized to deliver energy from a customer-generator depends on a host of factors, including the amount of distributed generation delivered to the grid in a particular

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and are present regardless of the direction of current flow in a transformer. Consequently, core losses cannot be avoided by distributed distribution.

[6] I^2R losses relate to resistance in conductor and transformer windings and are in proportion to the square of the current. Because any energy generated by customer-generator must flow through conductor and transformers windings, such energy will always create I^2R losses. Consequently, these I^2R losses will not be avoided by customer-generators supplying energy to the grid.

[7] The primary voltage system are distribution facilities at rated voltages of 2400/4160Y volts, 7200/12,470Y volts, 13,800 volts, or 34,500 volts.

location, congestion on the system, the length of primary and secondary lines serving distributed generation customers, and many other factors. Because actual avoided line losses would vary from customer-generator to customer-generator, any value placed on avoided line losses would represent a generalized estimate. As I explained above, for the transmission system, it is only possible to avoid I^2R losses. Because they are fixed, it is unreasonable to assume that core losses on the transmission system could be avoided by energy supplied to the grid by customer-generators.

Q. What is that maximum transmission loss factor you would recommend for KU and LG&E?

A. Based on the Companies' loss study, for KU the loss factor (input/output) for variable losses on the transmission system, including generation step-up transformers (GSUs), is 2.560%.[8] For LG&E, the loss factor for variable losses on the transmission system, including GSUs, is 0.807%.[9] KU's transmission loss factor is greater than LG&E's transmission loss factor because KU's transmission system is spread out across the Commonwealth of Kentucky and Virginia, whereas LG&E's transmission system is localized to the service territory around Jefferson County and surrounding counties in Kentucky.

Q. What is the maximum distribution loss factor you would recommend for KU and LG&E?

[8] 2.8227% x (71.2% ÷78.5%) = 2.56%. *See* KU's response to PSC 5-20 at pp. 4-6.
[9] 1.033% x (16.8% ÷ 21.5%) = 0.806%. *See* LG&E's response to PSC 5-20 at pp. 4-6.

A. Based on the Companies' loss study, for KU the loss factor for variable losses on the primary system is 1.572%.[10] For LG&E, the loss factor for variable losses on the primary system is 1.414%.[11] These estimates assume that variable losses represent 80% of total primary line losses and that 90% of these losses could be avoided by a customer-generator. In other words, it is assumed that 10% of the energy delivered by customer-generators would be transmitted through the primary system. This is a conservative estimate because it is likely that more than 10% of energy supplied to the grid would flow through the primary system. Because all energy delivered by a customer-generator would have to flow through the secondary system, no avoided secondary voltage losses are attributed to the customer-generators.

Q. What total maximum loss factor you would recommend?

A. For KU, I am recommending a loss factor of 4.132% (2.560% + 1.572% = 4.132%), and for LG&E, I am recommending a loss factor of 2.220% (0.806% + 1.414% = 2.220%). Based on an avoided energy cost of $0.02319 per kWh, the avoided loss value is $0.00100 per kWh for KU and $0.00053 per kWh for LG&E.

Q. Should a financial hedging value be included as avoided energy costs?

A. No. Although any financial hedging value for the SQF would be extremely small, I do not believe that it should be included. Neither KU nor LG&E uses financial hedges for its fuel costs. Because the SQF rate is updated every two years, there is little reason to provide a hedging value. Furthermore, the Commission has never required

[10] (5.011%-2.827%) x 80% x 90% = 1.57%. *See* KU's response to PSC 5-20 at p.2.
[11] (2.998%-1.033%) x 80% x 90% = 1.414%. *See* LG&E's response to PSC 5-20 at p.2.

KU and LG&E to financially hedge their fuel costs. Therefore, in my view, it would be inconsistent and inappropriate to provide a hedging value to customers when the Companies do not hedge their own fuel costs on behalf of ratepayers.

Q. Would it be appropriate to use the Black-Scholes formula to calculate a hedging value?

A. No. The Black-Scholes formula was developed to value European-style financial options. It is unclear why a hedging value for SQF should be based on a European-style call option rather than an American-style call option.[12] Furthermore, one of the more difficult input values to calculate for a Black-Scholes model is price volatility. In the academic literature, there is no consensus on the appropriate methodology for calculating price volatility for use in a Black-Scholes model. It is uncertain how price volatility would be calculated based on the Companies' fuel mix using the Black-Scholes differential equation.

IV. AVOIDED ANCILLARY SERVICE COST

Q. What ancillary service charges are set forth in KU and LG&E's Open Access Transmission Tariff (OATT)?

A. The Companies' OATT has standard rates for the following ancillary services, which apply to customers that transmit power across their transmission system: (a) Schedule 1: Scheduling, System Control and Dispatch; (b) Schedule 2: Reactive Supply and

[12] European-style call options can be calculated analytically (in closed form) using the Black-Scholes formula, while the stochastic differential equation for an American-style options must be approximated using numerical differential equation methodologies.

Voltage Control; (c) Schedule 3: Regulation and Frequency Response; (d) Schedule 4: Energy Imbalance Service; (e) Schedule 5: Spinning Reserve Service; (f) Schedule 6: Operating Reserve Service; and (g) Schedule 9: Generator Imbalance Service.

Q. What is Schedule 1 and how is the rate calculated?

A. Schedule 1 is an ancillary service charge that applies to power that is transmitted for third parties across the Companies' transmission systems. The charge is designed to assign a portion of the expenses recorded in FERC Account No. 561 to transmission customers. The Schedule 1 charge is updated annually based on annual expenses recorded in Account No. 561. Costs recorded in Account No. 561 primarily relate to the operation of the Companies' transmission load dispatch operations. The costs recorded in Account No. 561 are fixed costs that do not vary directly with energy generated by the Companies or transmitted across the Companies' transmission system.

Q. Would energy provided by NMS-2 customer-generators avoid any of these costs?

A. No. The Companies' load dispatch operation will need to be in place regardless of whether customer-generators supply energy to the grid. The energy supplied by customer-generators do not impact these costs. Therefore, there is no avoided cost associated with Schedule 1.

Q. What is Schedule 2 and how is the rate calculated?

A. Schedule 2 is an ancillary service charge that applies to power that is transmitted for third parties across the Companies' transmission systems. The charge is designed to assign a portion of the costs of the electrical systems of the Companies' generators that can be used to provide or absorb reactive power. The costs recovered through the charge relate to the stator and control systems of the Companies' existing generators. These costs are not separate from the overall costs of the generators but are costs associated with integral components of the generator. For example, the stator is the stationary component of the generator that surrounds the rotating components of the generator (i.e., the rotor).

Q. Would energy provided by NMS-2 customer-generators avoid any of these costs?

A. Not in addition to any generation capacity costs that might be avoided from energy supplied to the grid by customer-generators. If energy supplied to the grid were to avoid or defer a generating unit, the components of the generating unit that could supply reactive power would be avoided too. As explained above, the components of generators that supply reactive power are integral to the generators themselves. To the extent that a generator is avoided or deferred, the components of the generator that can supply reactive power are included in the avoided cost of the generator.

Q. Would this also apply to a solar power plant?

A. Yes. Large-scale solar power plants can also generate or absorb reactive power with use of a smart inverter. As with a stator and stator control system in a conventional generator, a power inverter and inverter control system (collectively, "smart inverter") can be used to generate or absorb reactive power, and as with a stator and stator control system, the smart inverter is an integral component of a modern solar power plant. Therefore, regardless of whether the avoided generator capacity is any kind of conventional unit (coal-fired or combustion turbine) or a solar power plant, this kind of ancillary service capability is compensated in the cost of the plant or unit itself.

Q. Therefore, is it appropriate to include a separate component for reactive power as an avoided cost for energy supplied to the grid by customer-generators?

A. No. To the extent that energy supplied by a customer-generator can avoid any generation capacity cost (whether it is the cost of a conventional generator or solar plant), any avoided cost related to reactive power would be included in the capacity cost. Providing an additional avoided cost for reactive power would result in double counting a portion of the avoided capacity costs.

Q. What is Schedule 3 and how is the rate calculated?

A. Schedule 3 is an ancillary service charge that applies to power that is transmitted for third parties across the Companies' transmission systems. The charge is designed to assign a portion of the costs of providing continuous balancing from the Companies' generation resources. The charge is equal to 1% of the *embedded* peaking generation capacity cost when the charge was developed.

Q. Does the Schedule 3 charge represent an avoided cost?

A. No. Again, it represents an embedded cost determined at the time when it was last filed with the FERC.

Q. Would energy provided by NMS-2 customer-generators avoid any of these costs?

A. No. For intermittent resources such as solar or wind facilities, it is difficult to understand how such resources could provide continuous balancing services that would warrant compensation as ancillary services. It is therefore my recommendation that energy supplied to the grid from NMS-2 customers should not receive a compensation for this service.

Q. If the Commission determines that an avoided cost should be imputed for Schedule 3, what are the alternatives?

A. I see two alternatives. First, compensation could be based on the Schedule 3 charges set forth in the Companies' OATT. Second, the charge could be determined as 1% of the avoided generation capacity cost approved by the Commission in the export compensation rate for NMS-2.

Q. What would the charge be under the current Schedule 3 ancillary service rate?

A. Under the current Schedule 3 rate, the avoided cost would be $0.00010 per kWh ($0.0095 x 1% = $0.00010 per kWh).

Q. Please describe the alternative approach that could be used to determine the avoided cost related to the Schedule 3 ancillary service.

A. An avoided cost component for Schedule 3 could be determined by simply multiplying 1% times any avoided generation capacity cost that should be provided to customer-generators. Of course, if the avoided generation capacity cost is determined to be zero then the avoided cost for the Schedule 3 ancillary service would be zero. But if the avoided charge is determined to have a non-zero value, then the avoided cost of the Schedule 3 ancillary service charge would be determined by multiply the avoided generation cost per kWh by 1%. For example, if the Companies' avoided generation capacity cost is determined to be $0.00181 per kWh then the Schedule 3 avoided cost would be $0.00002 per kWh ($0.00181 per kWh x 1% = $0.00002 per kWh).

Q. What is Schedule 4?

A. Schedule 4 is an ancillary service charge that applies only to differences that occur between the scheduled and actual delivery of energy by a customer transmitting power across the Companies' transmission system.

Q. Is it appropriate to include a separate component for Schedule 4 imbalance service as an avoided cost for energy supplied to the grid by customer-generators?

A. No. Because Schedule 4 only applies to imbalances between scheduled and delivered energy by an OATT customer, it would be impossible for customer-generation to affect these costs. Because the energy supplied by a customer-generator does not impact imbalances created by OATT customers, avoided costs should not and cannot be calculated for this ancillary service.

Q. What is Schedule 5 and how is the rate calculated?

A. Schedule 5 is an ancillary service charge that applies to power that is transmitted for third parties across the Companies' transmission systems. The charge is designed to assign a portion of the costs of providing spinning reserve on the system. Similar to Schedule 5, the charge is equal to 1.5% of the *embedded* generation capacity cost when the charge was developed.

Q. Does the Schedule 5 charge represent an avoided cost?

A. No. As with Schedule 3, Schedule 5 represents an embedded cost determined at the time when it was last filed with the FERC.

Q. Would energy provided by NMS-2 customer-generators avoid any of these Schedule 5 costs?

A. I do not believe they would. For intermittent resources such as solar or wind facilities, it is difficult to understand how such resources could provide spinning reserve services that would warrant compensation as ancillary services. Indeed, more spinning reserves may be needed to accommodate increasing amounts of intermittent resources. It is therefore my recommendation that energy supplied to the grid for NMS-2 customers should not receive a compensation for this service.

Q. If the Commission determines that an avoided cost should be imputed for Schedule 5, what are the alternatives?

A. Again, I see two alternatives. First, compensation could be based on the Schedule 5 charges set forth in the Companies' OATT. Second, the charge could be determined as 1.5% of the avoided generation capacity cost approved by the Commission for NMS-2.

Q. What would the charge be under the current Schedule 5 ancillary service rate?

A. Under the current Schedule 5 rate, the avoided cost would be $0.00031 per kWh ($0.0206 x 1.5% = $0.00031 per kWh).

Q. Please describe the alternative approach that could be used to determine the avoided cost related to the Schedule 5 ancillary service.

A. An avoided cost component for Schedule 5 could be determined by multiplying 1.5% times any avoided generation capacity cost that should be provided to customer-generators. If the avoided generation capacity cost is determined to be zero, then the avoided cost for the Schedule 5 ancillary service would be zero. But if the avoided charge is determined to have a non-zero value, then the avoided cost of the Schedule

5 ancillary service charge would be determined by multiply the avoided generation cost per kWh by 1.5%. For example, if the Companies' avoided generation capacity cost is determined to be $0.00181 per kWh then the Schedule 5 avoided cost would be $0.00003 per kWh ($0.00181 per kWh x 1.5% = $0.00003 per kWh).

Q. What is Schedule 6 and how is the rate calculated?

A. Schedule 6 is an ancillary service charge that applies to power that is transmitted for third parties across the Companies' transmission systems. The charge is designed to assign a portion of the costs of providing supplemental reserve on the system. As with Schedule 5, the charge is equal to 1.5% of the ***embedded*** generation capacity cost when the charge was developed.

Q. Does the Schedule 6 charge represent an avoided cost?

A. No. As with Schedules 3 and 5, Schedule 6 represents an embedded cost determined at the time when it was last filed with the FERC.

Q. Would energy provided by NMS-2 customer-generators avoid any of these Schedule 6 costs?

A. Again, I do not believe that they would. For intermittent resources such as solar or wind facilities, it is difficult to understand how such resources could provide operating reserve services that would warrant compensation as ancillary services. It is therefore my recommendation that energy supplied to the grid for NMS-2 customers should not receive a compensation for this service.

Q. If the Commission determines that an avoided cost should be imputed for Schedule 6, what are the alternatives?

A. Once again, I see the two alternatives. First, compensation could be based on the Schedule 5 charges set forth in the Companies' OATT. Second, the charge could be determined as 1.5% of the avoided generation capacity cost approved by the Commission for NMS-2.

Q. What is the charge be under the current Schedule 6 ancillary service rate?

A. Under the current Schedule 6 rate, the avoided cost would be $0.00031 per kWh ($0.0206 x 1.5% = $0.00031 per kWh).

Q. Is there an alternative approach that could be used to determine the avoided cost related to the Schedule 6 ancillary service?

A. Yes. An avoided cost component for Schedule 6 could be determined by multiplying 1.5% times any avoided generation capacity cost that should be provided to customer-generators. If the avoided generation capacity cost is determined to be zero, then the avoided cost for the Schedule 6 ancillary service would be zero. But if the avoided charge is determined to have a non-zero value, then the avoided cost of the Schedule 6 ancillary service charge would be determined by multiply the avoided generation cost per kWh by 1.5%. For example, if the Companies' avoided generation capacity cost is determined to be $0.00181 per kWh then the Schedule 6 avoided cost would be $0.00003 per kWh ($0.00181 per kWh x 1.5% = $0.00003 per kWh).

Q. What is Schedule 9?

A. Schedule 9 is an ancillary service charge that applies only to differences that occur between the output of a generator located in the Transmission Owner's Balancing Authority and a delivery schedule provided by the generator.

Q. Is it appropriate to include a separate component for Schedule 9 imbalance service as an avoided cost for energy supplied to the grid by customer-generators?

A. No. Because Schedule 9 only applies to imbalances between scheduled and delivered energy by a generator in the Companies' Balancing Authority, it would be impossible for customer-generation to affect the imbalances created by an OATT generator customer. Because the energy supplied by a customer-generator does not impact imbalances created by OATT generator customers, avoided costs should not and cannot be calculated for this ancillary service.

V. AVOIDED GENERATION CAPACITY COST

Q. What are generation capacity costs?

A. Avoided generation capacity costs are generation capacity or purchased capacity costs that can be avoided or deferred by energy supplied to the grid by a customer-generator.

Q. Should customer-generators that supply energy to the grid receive an avoided capacity component?

A. No. As I explained in my direct and rebuttal testimonies, energy supplied from solar facilities is intermittent and fundamentally as-available. Therefore, the energy supplied from customer-generators cannot be relied upon to avoid generation capacity costs. Because customer-generators are providing energy to the grid on an as-available basis with no legally enforceable obligation to provide firm energy or capacity, the appropriate avoided capacity cost component is zero. With customer-generators there is no assurance that their solar facilities will be in place over a sufficiently long period of time to allow the Companies to avoid or defer generation capacity. In order to allow the Companies to avoid generation capacity, KU and LG&E must have some assurance that any capacity provided by a customer-generator would be in place and operational over a period of time of 20 years or more. It would not be possible for a customer-generator taking service under NMS-2 to make such an assurance. It is not realistic to assume that customer-generators could provide a legally enforceable commitment to provide capacity over a 20-year period.

Q. If the Commission determines that an avoided capacity component should be provided to net metering customers, what is the maximum generation capacity value that should be provided?

A. In no event should the energy cost and capacity value provided to customer-generators exceed the cost that the Companies would incur from purchasing power from a solar purchased power agreement. As explained earlier, 807 KAR 5:054 Sec. 1(1) defines avoided costs as the "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***."[13] As explained in Mr. Sinclair's supplemental testimony, the Companies recently purchased the entire output of a solar farm under a 20-year solar PPA at a cost of $0.02782 per kWh. Thus, at a maximum, any energy supplied to the grid by customer-generators with solar facilities

[13] Emphasis supplied.

would only avoid $0.02782 per kWh whenever the Companies have a need for capacity on their systems. This avoided cost should therefore only apply when the Companies have a capacity need, which is not until at least 2028. Thus, as Mr. Sinclair explains in his supplemental testimony, the avoided generation capacity cost for a 20-year purchase agreement that begins in 2022 is $0.00170/kWh, and the avoided generation capacity cost for a 20-year purchase agreement that begins in 2023 is $0.00191/kWh. Of course, these avoided generation capacity costs assume that the Fixed Tilt Solar facilities would provide energy for a 20-year period.

Q. Therefore, what is the maximum avoided generation capacity cost that should be paid to customer-generations under NMS-2?

A. The maximum avoided generation-capacity cost that should be paid to customer-generators under NMS-2 for the next two years is the average of the price that would be paid to qualifying facilities under SQF and LQF assuming a 20-year contract. For a 20-year contract the avoided generation capacity cost for Fixed Tilt Solar is $0.00170/kWh for a contract purchase beginning in 2022 and $0.00191 for a contract purchase beginning in 2023. The average for 2022 and 2023 is $0.00181 per kWh, which is the maximum avoided capacity value that would be provided for the energy that NMS-2 customer-generators supply to the grid. Again, this calculation of avoided generation capacity cost assumes that the customer-generator would be in a position to supply the energy for a period of at least 20 years, which is not actually realistic. It is unreasonable to expect the Companies to be able to enforce a 20-year contract with residential net metering customers who may or may not remain at the same location for 20 years or want to continue to operate solar panels.

VI. AVOIDED TRANSMISSION CAPACITY COST

Q. Is it likely that net metering will result in any avoided transmission capacity costs?

A. No. As explained in Ms. McFarland's supplemental testimony, it is unlikely that net metering would result in any avoided transmission capacity costs. KU and LG&E serve relatively few net metering customers. Consequently, net metering has had, and is expected in the future to have, little or no impact on future transmission capacity costs. Additionally, the impact of changes in loads or resources on the transmission system depend on location. Furthermore, because of the penetration of space heating on KU's system, any impact of net metering on KU's transmission system would be even less than the impact on LG&E's transmission system. Because solar generators cannot supply energy during the winter peaks, it is extremely unlikely that solar generation could avoid any costs on KU's transmission system.

Q. Should an avoided cost component for transmission capacity be included in the export compensation rate for NMS-2 energy supplied to the grid?

A. No. The Companies have not been able to identify any avoided costs related to the energy that customer-generators supply to grid. Furthermore, considering that the Companies' system loads are projected to *decrease* over the next ten years, the Companies' existing transmission infrastructure should generally be adequate to serve future loads on the system. Consequently, the energy supplied to the grid by customer-generators will not likely avoid any future plant investment. Although the Companies are planning to make small plant additions in certain regions of their transmission system to serve new localized load, the load-related investments in those regions are small. For example, KU's total transmission plant investment per books was $1,289,233,917 as of December 31, 2020. During the period 2022 through 2031, KU's projected total transmission plant additions for retail load growth is only $34,200,000. Calculating the annual carrying costs on this investment results in an annual revenue requirement of $4,316,573. Dividing this annual revenue requirement by annual kWh sales would result in an average avoided transmission cost of only $0.00025 per kWh.[14] Therefore, at most the avoided cost could only be $0.00025 per kWh, which is essentially zero. The reality is that there are not many costs on KU's transmission system to avoid.

Q. Is the situation the same on LG&E's transmission system?

A. Yes. During the period 2022 through 2031, LG&E's projected total transmission plant additions for retail load growth is only $7,837,000. Calculating the annual carrying costs on this investment results in an annual revenue requirement of $1,087,091. Dividing this annual revenue requirement by annual kWh sales would result in an average avoided transmission cost of only $0.00010 per kWh.[15] Therefore, at a maximum, the avoided transmission cost for LG&E could only be $0.00010 per kWh. Again, the reality is that there is not much cost on LG&E's transmission system to

[14] *See* Supplemental Exhibit WSS-1.
[15] *Id*.

avoid.

VII. AVOIDED DISTRIBUTION CAPACITY COST

Q. Is it likely that net metering will result in any avoided distribution capacity costs?

A. No. As explained in Ms. Wolfe's supplemental testimony, it is unlikely that net metering would result in any avoided distribution costs. Again, because of the penetration of space heating on KU's system, any impact of net metering on KU's distribution system would be less than the impact on LG&E's distribution system. Because solar generators cannot supply energy during the winter peaks, it is extremely unlikely that solar generation could avoid any costs on KU's distribution system.

Q. Should an avoided cost component for distribution capacity be included in the export compensation rate for NMS-2 energy supplied to the grid?

A. No. The Companies have not been able to identify any avoided distribution costs related to the energy that customer-generators supply to grid. The energy supplied to the grid by customer-generators will not likely avoid any future plant investment. As with the transmission system, the Companies are planning to make only small plant additions in certain regions of their distribution systems to serve new loads. During the period 2022 through 2031, KU is projected to add only $69,681,000 million in load related distribution investments. Considering that KU is a winter peaking utility, it is unlikely that any of these costs could be avoided with solar generation. But calculating the annual carrying costs on this investment results in an annual revenue requirement of $8,077,180. Dividing this annual revenue requirement by annual kWh sales would result in an average avoided distribution cost of only \$0.00046 per kWh.[16] Therefore, at most the avoided cost could only be \$0.00046 per kWh.

Q. Is the situation the same on LG&E's distribution system?

A. Yes, except there are fewer costs to avoid. During the period 2022 through 2031, LG&E's projected total distribution plant additions for retail load growth is only \$13,761,000. Calculating the annual carrying costs on this investment results in an annual revenue requirement of \$1,404,930. Dividing this annual revenue requirement by annual kWh sales would result in an average avoided distribution cost of only \$0.00012 per kWh.[17] Therefore, at a maximum, the avoided distribution cost for LG&E would only be \$0.00012 per kWh. Again, there are not many costs on KU and LG&E's distribution systems to avoid.

VIII. AVOIDED CARBON AND ENVIRONMENTAL COMPLIANCE COSTS

Q. Should avoided CO_2 and environmental compliance costs be included as avoided costs for compensating customer-generators that supply energy to the grid?

A. No. As explained in Mr. Sinclair's testimony, currently there are no laws or regulations that put a price on CO_2 emissions. If a price is placed on CO_2 emissions in the future, then an avoided cost could be included in a future filing. Also as explained in Mr. Sinclair's testimony, avoided environmental compliance costs are fully accounted for in the avoided energy and capacity cost components. Therefore,

[16] *See* Supplemental Exhibit WSS-2.
[17] *Id*.

adding a non-zero avoided environmental compliance cost component would double-count those avoided costs and over-compensate NMS-2 customers.

IX. JOB BENEFITS

Q. Should job benefits be provided to NMS-2 credits for the energy customer-generators supply to the grid?

A. No. As explained in Mr. Conroy's supplemental testimony, a jobs-related component should not be provided in the compensation rate for energy that customer-generators supply to the grid because job creation is not within the Commission's jurisdiction. Furthermore, because jobs creation would not affect the Companies' cost of providing service, an avoided cost component for jobs creation should not be included in avoided costs.

Moreover, adding compensation components like jobs creation that lack a direct connection to utility rates is concerning because of the absence of any limiting principle. Once the constraint of a direct, causal link to cost of service is removed, there is no boundary to what could be included in this or any other rate. Therefore, I respectfully suggest that the Commission choose not to include a jobs creation component in NMS-2 export compensation rates.

X. SUMMARY OF AVOIDED COST COMPONENTS FOR NMS-2

Q. Please summarize the avoided costs that you would recommend for the export compensation rate under NMS-2.

A. The following table shows the recommended avoided cost components for NMS-2 and an alternative set of high-case avoided cost components. As explained, based on a review of its costs, it is the Companies' conclusion that many of components that the Commission directed the Companies to address have zero avoided costs.

Avoided Cost Component	Kentucky Utilities Company		Louisville Gas & Electric Company	
	Recommended Avoided Cost ($/kWH)	Maximum Avoided Cost ($/kWH)	Recommended Avoided Cost ($/kWH)	Maximum Avoided Cost ($/kWH)
Avoided Energy Cost				
Avoided Energy Cost	$ 0.02319	$ 0.02319	$ 0.02319	$ 0.02319
Line Losses	None	$ 0.00100	None	$ 0.00053
Hedging Value	None	None	None	None
Total Avoided Energy Cost	$ 0.02319	$ 0.02419	$ 0.02319	$ 0.02372
Avoided Ancillary Service Cost	None	$ 0.00006	None	$ 0.00006
Avoided Generation Capacity Cost	None	$ 0.00181	None	$ 0.00181
Avoided Transmission Capacity Cost	None	$ 0.00025	None	$ 0.00010
Avoided Distribution Capacity Cost	None	$ 0.00046	None	$ 0.00012
Avoided Environmental Cost	None	None	None	None
Jobs Benefit	None	None	None	None
Total	**$ 0.02319**	**$ 0.02677**	**$ 0.02319**	**$ 0.02581**

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF BUNCOMBE)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

W. Seelye
William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13 day of July 2021.

Bryant P. Cooper
Notary Public
Buncombe County, NC
My Commission Expires: 03/07/26

_______________ (SEAL)
Notary Public

Notary Public ID No. 202106900001

My Commission Expires:

3/7/26

Capacity-Related Transmission Investment
2021 Business Plan
($ in Thousands)

Year	**KU**	**LG&E**	**Total**
2022	15,884	434	16,318
2023	6,329		6,329
2024	7,191		7,191
2025	97		97
2026			0
2027			0
2028	384	1,241	1,625
2029	4,081	3,261	7,342
2030		2,901	2,901
2031	234		234
10-Year Total	34,200	7,837	42,037

Carrying Cost Percentage	12.62%	13.87%
Annualized Avoided Costs (in $)	$4,316,573	$1,087,091
Sales to Ultimate Consumers (kWh)	17,402,124,383	11,352,592,560
Avoided Cost per kWh	$0.00025	$0.00010

Assumptions:

Investment	$	1,000.000
Book Life		40
Tax Life		20
Composite Tax Rate		24.83%
Property Tax Rate		0.32%
Levelized Revenue Requirement Years		40

Results:		**Transmission**		**Distribution**
Present Value Revenue Requirement	$	1,194	$	1,194
Levelized Revenue Requirement	$	88	$	88
234		8.78%		8.78%
O&M Cost		3.85%		2.76%
Total Carrying Costs		12.62%		11.53%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		$ 25	$ 975	$ 38	$ 963	$ 3	$ 3
2		25	950	72	890	12	15
3		25	925	67	824	10	25
4		25	900	62	762	9	34
5		25	875	57	705	8	42
6		25	850	53	652	7	49
7		25	825	49	603	6	55
8		25	800	45	558	5	60
9		25	775	45	513	5	65
10		25	750	45	468	5	70
11		25	725	45	424	5	75
12		25	700	45	379	5	80
13		25	675	45	335	5	85
14		25	650	45	290	5	89
15		25	625	45	245	5	94
16		25	600	45	201	5	99
17		25	575	45	156	5	104
18		25	550	45	112	5	109
19		25	525	45	67	5	114
20		25	500	45	22	5	119
21		25	475	22	(0)	(1)	118
22		25	450	-	(0)	(6)	112
23		25	425	-	(0)	(6)	106
24		25	400	-	(0)	(6)	99
25		25	375	-	(0)	(6)	93
26		25	350	-	(0)	(6)	87
27		25	325	-	(0)	(6)	81
28		25	300	-	(0)	(6)	74
29		25	275	-	(0)	(6)	68
30		25	250	-	(0)	(6)	62
31		25	225	-	(0)	(6)	56
32		25	200	-	(0)	(6)	50
33		25	175	-	(0)	(6)	43
34		25	150	-	(0)	(6)	37
35		25	125	-	(0)	(6)	31
36		25	100	-	(0)	(6)	25
37		25	75	-	(0)	(6)	19
38		25	50	-	(0)	(6)	12
39		25	25	-	(0)	(6)	6
40		25	-	-	(0)	(6)	(0)

Assumptions:

Investment	$ 1,000
Book Life	40
Tax Life	20
Composite Tax Rate	24.83%
Property Tax Rate	0.32%
Levelized Revenue Requirement Years	40

Results:	**Transmission**	**Distribution**
Present Value Revenue Requirement	$ 1,194	$ 1,193.95
Levelized Revenue Requirement	$ 88	$ 87.76
Levelized Carrying Charge Rate	8.78%	8.78%
O&M Costs	3.85%	2.76%
Total Carrying Costs	12.62%	11.53%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 972	$ 0	$ 66	$ 3	$ 22	$ 116	0.940074	109
2	935	0	64	3	21	113	0.883739	100
3	900	0	61	3	20	110	0.830780	91
4	866	0	59	3	19	106	0.780995	83
5	833	0	57	3	19	103	0.734193	76
6	801	0	55	3	18	100	0.690195	69
7	770	0	52	3	17	98	0.648835	63
8	740	0	50	3	17	95	0.609952	58
9	710	0	48	2	16	92	0.573400	53
10	680	0	46	2	15	89	0.539039	48
11	650	0	44	2	15	86	0.506736	44
12	620	0	42	2	14	84	0.476370	40
13	590	0	40	2	13	81	0.447823	36
14	561	0	38	2	13	78	0.420986	33
15	531	0	36	2	12	75	0.395758	30
16	501	0	34	2	11	72	0.372042	27
17	471	0	32	2	11	70	0.349747	24
18	441	0	30	2	10	67	0.328788	22
19	411	0	28	2	9	64	0.309085	20
20	381	0	26	2	9	61	0.290563	18
21	357	0	24	2	8	59	0.273151	16
22	338	0	23	1	8	57	0.256782	15
23	319	0	22	1	7	55	0.241394	13
24	301	0	20	1	7	54	0.226928	12
25	282	0	19	1	6	52	0.213329	11
26	263	0	18	1	6	50	0.200545	10
27	244	0	17	1	6	48	0.188527	9
28	226	0	15	1	5	46	0.177229	8
29	207	0	14	1	5	45	0.166609	7
30	188	0	13	1	4	43	0.156625	7
31	225	0	15	1	5	46	0.147239	7
32	200	0	14	1	5	44	0.138415	6
33	175	0	12	1	4	41	0.130121	5
34	150	0	10	0	3	39	0.122323	5
35	125	0	9	0	3	37	0.114993	4
36	100	0	7	0	2	34	0.108102	4
37	75	0	5	0	2	32	0.101623	3
38	50	0	3	0	1	30	0.095534	3
39	25	0	2	0	1	27	0.089809	2
40	-	-	-	-	-	25	0.084427	2

Net Present Value Revenue Requirement $ 1,194

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	2.46%	0.46%	0.01%	24.83%	0.01%
Long Term Debt	44.41%	4.04%	1.79%	24.83%	1.35%
Common Equity	53.14%	9.43%	5.01%		5.01%
			6.81%		6.37%

Tax Depreciation Table (MACRS)

	5		15	20
1	23400.000%		5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Assumptions:

Investment	$	1,000.000
Book Life		40
Tax Life		20
Composite Tax Rate		24.8495%
Property Tax Rate		0.59%
Levelized Revenue Requirement Years		40

Supplemental Exhibit WSS-1
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Results:		**Transmission**		**Distribution**
234	$	1,219.95	$	1,219.95
Levelized Revenue Requirement	$	89.67	$	89.67
Levelized Carrying Charge Rate		8.97%		8.97%
O&M Cost		4.90%		1.18%
Total Carrying Costs		13.87%		10.15%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		$ 25	$ 975	$ 38	$ 963	$ 3	$ 3
2		25	950	72	890	12	15
3		25	925	67	824	10	25
4		25	900	62	762	9	34
5		25	875	57	705	8	42
6		25	850	53	652	7	49
7		25	825	49	603	6	55
8		25	800	45	558	5	60
9		25	775	45	513	5	65
10		25	750	45	468	5	70
11		25	725	45	424	5	75
12		25	700	45	379	5	80
13		25	675	45	335	5	85
14		25	650	45	290	5	89
15		25	625	45	245	5	94
16		25	600	45	201	5	99
17		25	575	45	156	5	104
18		25	550	45	112	5	109
19		25	525	45	67	5	114
20		25	500	45	22	5	119
21		25	475	22	(0)	(1)	118
22		25	450	-	(0)	(6)	112
23		25	425	-	(0)	(6)	106
24		25	400	-	(0)	(6)	99
25		25	375	-	(0)	(6)	93
26		25	350	-	(0)	(6)	87
27		25	325	-	(0)	(6)	81
28		25	300	-	(0)	(6)	75
29		25	275	-	(0)	(6)	68
30		25	250	-	(0)	(6)	62
31		25	225	-	(0)	(6)	56
32		25	200	-	(0)	(6)	50
33		25	175	-	(0)	(6)	43
34		25	150	-	(0)	(6)	37
35		25	125	-	(0)	(6)	31
36		25	100	-	(0)	(6)	25
37		25	75	-	(0)	(6)	19
38		25	50	-	(0)	(6)	12
39		25	25	-	(0)	(6)	6
40		25	-	-	(0)	(6)	0

Assumptions:

Investment	$ 1,000
Book Life	40
Tax Life	20
Composite Tax Rate	24.8495%
Property Tax Rate	0.59%
Levelized Revenue Requirement Years	40

Supplemental Exhibit WSS-1
Page 6 of 7

Results:

Present Value Revenue Requirement	$ 1,219.95	$ 1,219.95
Levelized Revenue Requirement	$ 89.67	$ 89.67
Levelized Carrying Charge Rate	8.97%	8.97%
O&M Costs	4.90%	1.18%
Total Carrying Costs	13.87%	10.15%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 972	$ 0	$ 66	$ 6	$ 22	$ 119	0.940074	112
2	935	0	64	6	21	115	0.883739	102
3	900	0	61	5	20	112	0.830780	93
4	866	0	59	5	20	109	0.780995	85
5	833	0	57	5	19	106	0.734193	78
6	801	0	55	5	18	103	0.690195	71
7	770	0	52	5	17	100	0.648835	65
8	740	0	50	5	17	97	0.609952	59
9	710	0	48	5	16	94	0.573400	54
10	680	0	46	4	15	91	0.539039	49
11	650	0	44	4	15	88	0.506736	45
12	620	0	42	4	14	85	0.476370	41
13	590	0	40	4	13	83	0.447823	37
14	561	0	38	4	13	80	0.420986	34
15	531	0	36	4	12	77	0.395758	30
16	501	0	34	4	11	74	0.372042	28
17	471	0	32	3	11	71	0.349747	25
18	441	0	30	3	10	68	0.328788	22
19	411	0	28	3	9	65	0.309085	20
20	381	0	26	3	9	63	0.290563	18
21	357	0	24	3	8	60	0.273151	16
22	338	0	23	3	8	58	0.256782	15
23	319	0	22	2	7	56	0.241394	14
24	301	0	20	2	7	55	0.226928	12
25	282	0	19	2	6	53	0.213329	11
26	263	0	18	2	6	51	0.200545	10
27	244	0	17	2	6	49	0.188527	9
28	225	0	15	2	5	47	0.177229	8
29	207	0	14	2	5	45	0.166609	8
30	188	0	13	1	4	44	0.156625	7
31	225	0	15	1	5	47	0.147239	7
32	200	0	14	1	5	44	0.138415	6
33	175	0	12	1	4	42	0.130121	5
34	150	0	10	1	3	39	0.122323	5
35	125	0	9	1	3	37	0.114993	4
36	100	0	7	1	2	35	0.108102	4
37	75	0	5	0	2	32	0.101623	3
38	50	0	3	0	1	30	0.095534	3
39	25	0	2	0	1	27	0.089809	2
40	-	-	-	-	-	25	0.084427	2

Net Present Value Revenue Requirement $ 1,220

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	1.53%	0.46%	0.01%	24.85%	0.01%
Long Term Debt	45.34%	4.04%	1.83%	24.85%	1.38%
Common Equity	53.13%	9.43%	5.01%		5.01%
			6.85%		6.39%

Tax Depreciation Table (MACRS)

	5		15	20
1	23400.000%		5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Capacity-Related Distribution Investment
2021 Business Plan
($ in Thousands)

Year	KU	LG&E	Total
2022	7,261		7,261
2023	9,705	3200	12,905
2024	8,357	2700	11,057
2025	2,024		2,024
2026	6,545	1215	7,760
2027	6,741	1252	7,993
2028	6,943	1289	8,232
2029	7,152	1328	8,480
2030	7,366	1368	8,734
2031	7,587	1409	8,996
10-Year Total	**69,681**	**13,761**	**83,442**

	KU	LG&E
Carrying Cost Percentage	11.59%	10.21%
Annualized Avoided Costs (in $)	$8,077,180	$1,404,930
Sales to Ultimate Consumers (kWh)	17,402,124,383	11,352,592,560
Avoided Cost per kWh	$0.00046	$0.00012

Kentucky Utilities
Carrying Charge Calculation

Assumptions:

Investment	$	1,000.000
Book Life		40
Tax Life		20
Composite Tax Rate		24.83%
Property Tax Rate		0.32%
Levelized Revenue Requirement Years		40

Results:	**Transmission**	**Distribution**
Present Value Revenue Requirement	$ 1,194	$ 1,194
Levelized Revenue Requirement	$ 88	$ 88
Levelized Carrying Charge Rate	8.83%	8.83%
O&M Cost	3.85%	2.76%
Total Carrying Costs	12.68%	11.59%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		$ 25	$ 975	$ 38	$ 963	$ 3	$ 3
2		25	950	72	890	12	15
3		25	925	67	824	10	25
4		25	900	62	762	9	34
5		25	875	57	705	8	42
6		25	850	53	652	7	49
7		25	825	49	603	6	55
8		25	800	45	558	5	60
9		25	775	45	513	5	65
10		25	750	45	468	5	70
11		25	725	45	424	5	75
12		25	700	45	379	5	80
13		25	675	45	335	5	85
14		25	650	45	290	5	89
15		25	625	45	245	5	94
16		25	600	45	201	5	99
17		25	575	45	156	5	104
18		25	550	45	112	5	109
19		25	525	45	67	5	114
20		25	500	45	22	5	119
21		25	475	22	(0)	(1)	118
22		25	450	-	(0)	(6)	112
23		25	425	-	(0)	(6)	106
24		25	400	-	(0)	(6)	99
25		25	375	-	(0)	(6)	93
26		25	350	-	(0)	(6)	87
27		25	325	-	(0)	(6)	81
28		25	300	-	(0)	(6)	74
29		25	275	-	(0)	(6)	68
30		25	250	-	(0)	(6)	62
31		25	225	-	(0)	(6)	56
32		25	200	-	(0)	(6)	50
33		25	175	-	(0)	(6)	43
34		25	150	-	(0)	(6)	37
35		25	125	-	(0)	(6)	31
36		25	100	-	(0)	(6)	25
37		25	75	-	(0)	(6)	19
38		25	50	-	(0)	(6)	12
39		25	25	-	(0)	(6)	6
40		25	-	-	(0)	(6)	(0)

Kentucky Utilities
Carrying Charge Calculation

Assumptions:			
Investment	$	1,000	
Book Life		40	
Tax Life		20	
Composite Tax Rate			
Property Tax Rate			
Levelized Revenue Requirement Years		40	

Results:	**Transmission**	**Distribution**
Present Value Revenue Requirement	$ 1,194	$ 1,194.16
Levelized Revenue Requirement	$ 88	$ 88.34
Levelized Carrying Charge Rate	8.83%	8.83%
O&M Costs	3.85%	2.76%
Total Carrying Costs	12.68%	11.59%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 972	$ 1	$ 66	$ 3	$ 22	$ 117	0.939713	110
2	935	1	64	3	21	113	0.883060	100
3	900	1	61	3	20	110	0.829823	91
4	866	1	59	3	19	107	0.779795	83
5	833	1	57	3	19	104	0.732784	76
6	801	1	55	3	18	101	0.688606	69
7	770	0	52	3	17	98	0.647092	63
8	740	0	50	3	17	95	0.608081	58
9	710	0	48	2	16	92	0.571421	53
10	680	0	46	2	15	90	0.536972	48
11	650	0	44	2	15	87	0.504599	44
12	620	0	42	2	14	84	0.474178	40
13	590	0	40	2	13	81	0.445591	36
14	561	0	38	2	13	78	0.418728	33
15	531	0	36	2	12	75	0.393484	30
16	501	0	34	2	11	73	0.369762	27
17	471	0	32	2	11	70	0.347470	24
18	441	0	30	2	10	67	0.326522	22
19	411	0	28	2	9	64	0.306837	20
20	381	0	26	2	9	61	0.288339	18
21	357	0	24	2	8	59	0.270955	16
22	338	0	23	1	8	57	0.254620	15
23	319	0	22	1	7	56	0.239270	13
24	301	0	20	1	7	54	0.224845	12
25	282	0	19	1	6	52	0.211290	11
26	263	0	18	1	6	50	0.198552	10
27	244	0	17	1	6	48	0.186582	9
28	226	0	15	1	5	47	0.175333	8
29	207	0	14	1	5	45	0.164763	7
30	188	0	13	1	4	43	0.154830	7
31	225	0	15	1	5	46	0.145495	7
32	200	0	14	1	5	44	0.136724	6
33	175	0	12	1	4	42	0.128481	5
34	150	0	10	0	3	39	0.120735	5
35	125	0	9	0	3	37	0.113457	4
36	100	0	7	0	2	34	0.106617	4
37	75	0	5	0	2	32	0.100189	3
38	50	0	3	0	1	30	0.094149	3
39	25	0	2	0	1	27	0.088473	2
40	-	-	-	-	-	25	0.083139	2

Net Present Value Revenue Requirement $ 1,194

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	2.46%	0.46%	0.01%	24.83%	0.01%
Long Term Debt	44.41%	4.04%	1.79%	24.83%	1.35%
Common Equity	53.14%	9.43%	5.01%		5.01%
			6.81%		6.37%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Louisville Gas & Electric
Carrying Charge Calculation

Assumptions:

Investment		$	1,000.000
Book Life			40
Tax Life	9.43%		20
Composite Tax Rate			24.8495%
Property Tax Rate			0.59%
Levelized Revenue Requirement Years			40

Results:		**Transmission**		**Distribution**
Present Value Revenue Requirement	$	1,220.06	$	1,220.06
Levelized Revenue Requirement	$	90.25	$	90.25
Levelized Carrying Charge Rate		9.03%		9.03%
O&M Cost		4.90%		1.18%
Total Carrying Costs		13.93%		10.21%

Year	**Investment**	**Book Depreciation**	**Net Plant**	**Tax Depreciation**	**Residual Plant**	**Deferred Income Tax**	**Accumulated Deferred Income Tax**
0	$ 1,000						
1		$ 25	$ 975	$ 38	$ 963	$ 3	$ 3
2		25	950	72	890	12	15
3		25	925	67	824	10	25
4		25	900	62	762	9	34
5		25	875	57	705	8	42
6		25	850	53	652	7	49
7		25	825	49	603	6	55
8		25	800	45	558	5	60
9		25	775	45	513	5	65
10		25	750	45	468	5	70
11		25	725	45	424	5	75
12		25	700	45	379	5	80
13		25	675	45	335	5	85
14		25	650	45	290	5	89
15		25	625	45	245	5	94
16		25	600	45	201	5	99
17		25	575	45	156	5	104
18		25	550	45	112	5	109
19		25	525	45	67	5	114
20		25	500	45	22	5	119
21		25	475	22	(0)	(1)	118
22		25	450	-	(0)	(6)	112
23		25	425	-	(0)	(6)	106
24		25	400	-	(0)	(6)	99
25		25	375	-	(0)	(6)	93
26		25	350	-	(0)	(6)	87
27		25	325	-	(0)	(6)	81
28		25	300	-	(0)	(6)	75
29		25	275	-	(0)	(6)	68
30		25	250	-	(0)	(6)	62
31		25	225	-	(0)	(6)	56
32		25	200	-	(0)	(6)	50
33		25	175	-	(0)	(6)	43
34		25	150	-	(0)	(6)	37
35		25	125	-	(0)	(6)	31
36		25	100	-	(0)	(6)	25
37		25	75	-	(0)	(6)	19
38		25	50	-	(0)	(6)	12
39		25	25	-	(0)	(6)	6
40		25	-	-	(0)	(6)	0

Louisville Gas & Electric
Carrying Charge Calculation

Assumptions:

Investment	$	1,000
Book Life		40
Tax Life		20
Composite Tax Rate		
Property Tax Rate		
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	1,220.06	$	1,220.06
Levelized Revenue Requirement	$	90.25	$	90.25
Levelized Carrying Charge Rate		9.03%		9.03%
O&M Costs		4.90%		1.18%
Total Carrying Costs		13.93%		10.21%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 972	$ 1	$ 66	$ 6	$ 22	$ 119	0.939713	112
2	935	1	64	6	21	116	0.883060	102
3	900	1	61	5	20	113	0.829823	93
4	866	1	59	5	20	109	0.779795	85
5	833	1	57	5	19	106	0.732784	78
6	801	1	55	5	18	103	0.688606	71
7	770	0	52	5	17	100	0.647092	65
8	740	0	50	5	17	97	0.608081	59
9	710	0	48	5	16	94	0.571421	54
10	680	0	46	4	15	92	0.536972	49
11	650	0	44	4	15	89	0.504599	45
12	620	0	42	4	14	86	0.474178	41
13	590	0	40	4	13	83	0.445591	37
14	561	0	38	4	13	80	0.418728	34
15	531	0	36	4	12	77	0.393484	30
16	501	0	34	4	11	74	0.369762	27
17	471	0	32	3	11	71	0.347470	25
18	441	0	30	3	10	69	0.326522	22
19	411	0	28	3	9	66	0.306837	20
20	381	0	26	3	9	63	0.288339	18
21	357	0	24	3	8	60	0.270955	16
22	338	0	23	3	8	59	0.254620	15
23	319	0	22	2	7	57	0.239270	14
24	301	0	20	2	7	55	0.224845	12
25	282	0	19	2	6	53	0.211290	11
26	263	0	18	2	6	51	0.198552	10
27	244	0	17	2	6	49	0.186582	9
28	225	0	15	2	5	47	0.175333	8
29	207	0	14	2	5	45	0.164763	7
30	188	0	13	1	4	44	0.154830	7
31	225	0	15	1	5	47	0.145495	7
32	200	0	14	1	5	44	0.136724	6
33	175	0	12	1	4	42	0.128481	5
34	150	0	10	1	3	40	0.120735	5
35	125	0	9	1	3	37	0.113457	4
36	100	0	7	1	2	35	0.106617	4
37	75	0	5	0	2	32	0.100189	3
38	50	0	3	0	1	30	0.094149	3
39	25	0	2	0	1	27	0.088473	2
40	-	-	-	-	-	25	0.083139	2

Net Present Value Revenue Requirement $ 1,220

Louisville Gas & Electric
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	1.53%	9.43%	0.14%	24.85%	0.11%
Long Term Debt	45.34%	4.04%	1.83%	24.85%	1.38%
Common Equity	53.13%	9.43%	5.01%		5.01%
			6.98%		6.49%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, 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**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS 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. 2020-00350**

SUPPLEMENTAL DIRECT TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: July 13, 2021

Table of Contents

Section 1 – Introduction and Overview

Q. Please state your name, position, and business address.

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe a common methodology and process for calculating avoided energy and generating capacity costs for the Companies' Riders LQF, SQF, and NMS-2. Based on this common methodology and process, I recommend changes to these tariff provisions so customers would pay appropriate avoided costs and to create a reasonable, principle-based incentive to develop renewable generating assets in the Companies' service area. For example, I am recommending that the Companies provide the option for LQF and SQF customers to lock in long-term avoided energy and capacity costs by entering into a 20-year PPA with the Companies while at the same time providing price certainty for two years to customers who wish to avoid long-term commitments and float with short-term avoided costs (similar to today's riders). The 20-year PPA option will create price certainty for generators of all sizes that should promote development while at the same time locking in long-term avoided costs for customers. I also recommend that the Companies file updated 24-year avoided energy and capacity costs and capacity needs with the Commission every two years so that potential LQF and SQF customers have access to the latest avoided cost information and future capacity needs. In total, my recommended changes provide equitable treatment of energy and capacity from renewable generation, regardless of its size and technology (e.g., solar, wind, greenfield), because from the perspective of the customer that is paying these costs, the avoided cost of a MWh of generation (excluding transmission and distribution costs) should be the same.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my direct testimony:

Supplemental Exhibit DSS-1	Avoided Energy Cost
Supplemental Exhibit DSS-2	Avoided Capacity Cost
Supplemental Exhibit DSS-3	Recommended LQF and SQF rates

Section 2 – Qualifying Facilities

Q. What is your understanding of the Companies' LQF and SQF riders?

A. According to the Public Utility Regulatory Policies Act of 1978 ("PURPA") as implemented in Kentucky by Commission regulations, 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.

[1] *See* 807 KAR 5:054.
[2] *See, e.g.,* 807 KAR 5:054 Section 1(10).

Q. What is the primary basis for determining QF compensation?

A. 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]

Q. In layman's terms, what is "avoided cost?"

A. The basic idea underlying the concept of avoided cost is that customers should pay no more for energy or capacity from a QF than they would pay for energy or capacity from a non-QF resource. The avoided cost concept is very important because, generally speaking, the Companies must purchase output and capacity from QFs for which the Companies' customers are going to pay. Logically, customers would not want the Companies to pay more for QF energy and capacity than they otherwise would pay for another resource. The purpose of PURPA's QF provisions as implemented in Kentucky is to allow non-utility renewable generation and co-generation to compete in the same terms as other utility resources while protecting customers (who ultimately have to pay the bill) from paying more than they otherwise would for power generation.

Q. What do you recommend using as the basis for calculating avoided energy cost in this case?

A. I recommend using the Companies' 2021 Business Plan ("2021 BP") which was the basis for the load and generation forecasts in this case for purposes of developing the forecasted test periods but with two minor modifications. When the 2021 BP was

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[3] *See* 807 KAR 5:054 Section 7(2) and (4).
[4] 807 KAR 5:054 Section 1(1).

finalized in the summer of 2020, the status of the 100 MW solar PPA with Rhudes Creek Solar, LLC was uncertain, so it was not included as part of the Companies' future generation fleet. Based on current information regarding the project, it is my opinion that it should be included in the Companies' generation fleet beginning in January 2023. Also, because this analysis is trying to identify avoided energy costs for the Companies' customers, I removed off-system sales from the 2021 BP. I described the load and generation forecast and the models used to calculate them in detail in my direct testimony and will not repeat that description here.[5]

Q. How did you use the 2021 BP to calculate avoided energy cost?

A. Supplemental Exhibit DSS-1 describes in detail the methodology used to calculate the avoided energy cost for four generation technologies based on their unique generation capabilities:

1. single axis tracking solar (26 percent annual capacity factor),
2. fixed tilt solar (16.7 percent annual capacity factor),
3. wind (25.3 percent annual capacity factor), and
4. other technologies (e.g., cogeneration facility with a steam host, hydro, biomass).

Basically, this methodology takes the hourly output from the Companies' PROSYM generation model for 2022 through 2045 (24 years) and computes the annual avoided energy cost by backing down generation using an hourly generation profile for each of the generation technologies assuming an 80 MW nameplate rated unit.

Q. Why did you back down generation by 80 MW to calculate avoided energy cost?

[5] *See* Direct Testimony of David S. Sinclair at 4-27.

A. The largest nameplate sized renewable QF allowed by 807 KAR 5:054 is 80 MW, so by comparing the cost of generation with and without this capacity, one can determine the incremental energy cost that would be avoided with this type of generation technology. Also, the one percent cap on net metering generating capacity would equate to approximately 60 MW in total for the combined Companies (about 35 MW for KU and about 25 MW for LG&E), so it is reasonable to use one set of 80 MW avoided energy cost data for LQF, SQF, and NMS-2. Given the general uncertainty in performing this calculation and the Companies' generation fleet, I do not believe that this 20 MW difference between the largest renewable QF and the cap on net metering capacity will produce a material difference in avoided energy costs.

Q. What types of costs are included in avoided energy costs?

A. Avoided energy costs can also be thought of as variable energy costs. These are costs that are associated with the generation of a MWh of energy. The largest category of avoided energy cost is fuel. Other avoided energy costs include SO_2 and NO_x emission allowances and emission system reagents (e.g., limestone, ammonia). See Supplemental Exhibit DSS-1 for a listing of the components of avoided energy costs in PROSYM. Note that, except for fuel, virtually every other category of variable energy costs is related to environmental compliance (e.g., emission allowances and operation of emission control equipment).

Q. Why are there no CO_2 costs included in avoided energy costs?

A. As of now, there are no laws or regulations that put a price on CO_2 like there are for SO_2 and NO_x, which is why the latter were included. If there is a price on CO_2 in the future, then it will be included in the Companies' next biennial avoided cost filing.[6]

Q. Since many QFs are likely to be renewable generation facilities, does the Companies' avoided energy cost include the value of Renewable Energy Certificates ("RECs")?

A. Not at this time because there is neither a federal nor a Kentucky renewable portfolio or clean energy standard that would require the Companies' to procure such attributes for customers. Just as in the case of CO_2 pricing, should there be a federal or Kentucky requirement to procure renewable energy in the future, the avoided energy cost would reflect that fact in a future biennial avoided cost filing.

Q. Does a QF have an obligation to provide RECs to the Companies as part of their PPA?

A. No. Because the Companies would not be paying for renewable attributes it would be unreasonable to expect a QF to voluntarily turn them over to the Companies at no charge.[7] Of course, QFs would be free to do whatever they please with any RECs that they create with their project.

Q. What avoided energy cost do you recommended should be used for the SQF and LQF rates?

A. Table 2 in Supplemental Exhibit DSS-1 shows the annual values for 2022 through 2045 of the Companies' avoided energy cost for each of the generation technologies. To

[6] Throughout this testimony, I am assuming that this initial 2-year period covers the balance of 2021 and all of 2022 and 2023. Thus, if this process is approved, the first biennial filing would be made in time for new rates to be effective January 1, 2024.

[7] American Ref-Fuel et al., FERC Docket No. EL03-133-000, 105 FERC ¶ 61,004 (FERC Oct. 3, 2003).

simplify tariff administration, I am recommending that these annual values be converted to levelized values based on the choice of 2-year or 20-year PPA and the starting year of the 20-year PPA. The levelization process is described in Supplemental Exhibit DSS-1. My recommended avoided energy prices by technology, contract term, and contract starting year are shown in Table 3 in Supplemental Exhibit DSS-1, which is replicated as Table 1 in Supplemental Exhibit DSS-3.

Q. Why are you recommending calculating avoided energy costs for 24 years when the existing SQF rate changes every two years and the existing LQF rate is based on monthly historical energy costs?

A. A long-term, fixed price can help in financing a QF or provide the price certainty necessary to support such an investment. One of my key recommendations is that both the SQF and LQF riders be modified to create the option for a 20-year fixed price PPA while retaining the 2-year PPA pricing option for SQF customers and replacing the historical monthly energy price in the current LQF rider with the same 2-year PPA pricing option as SQF customers.

Q. Another important concept for setting QF rates involves avoided generation capacity cost. What methods could the Companies use to determine their avoided generation capacity cost?

A. There are two logical methods to determine the Companies' future avoided generation capacity costs: current market prices and the levelized cost of a simple cycle combustion turbine ("CT"). Supplemental Exhibit DSS-2 describes both methodologies in detail.

Q. Please summarize the "current market price" methodology for calculating avoided capacity costs.

A. The justification for the Current Market Price method is that it mirrors the Companies' longstanding process for procuring capacity, namely going to the market for new capacity options and comparing the market to the cost of self-building new capacity. This process ensures that the Companies procure the least-cost capacity for their customers to meet their future needs. Thus, the Current Market Price method for determining avoided capacity cost depends on either a market index or the Companies' most recent PPA for a particular generation technology. The difference between the market index or PPA price and the avoided energy cost described in Supplemental Exhibit DSS-1 is presumed to represent that particular technology's potential capacity value to customers because a primary reason customers would be willing to pay more than just avoided energy costs is because they need capacity.

Q. What are you recommending as sources for market prices?

A. The best way to determine current market prices is to look at recent transactions. Sometimes, if the market is thinly traded or very volatile, it may be necessary to average a number of transactions over a period of time to get a better indication of market prices. For example, the Companies' only recent market price PPA is the Rhudes Creek 20-year solar PPA for a fixed price of $27.82 per MWh. Since the Companies issued a capacity RFP in January and are currently evaluating potential PPAs with other developers, it could be appropriate in future biennial avoided cost filings to average the Rhudes Creek PPA price with newer solar PPAs should they be executed.

Also, since the Companies do not have an abundance of PPA prices and have no wind PPAs, I have found a firm named LevelTen Energy that gathers renewable PPA data regionally and nationally and publishes renewable price indices for wind and solar by RTO called the LevelTen Energy PPA Price Index.[8] From 2019 quarter 4 (which corresponds to the execution of the Rhudes Creek PPA) through 2021 quarter 1 (the most recent data) in MISO and PJM, solar PPAs averaged $32.96 per MWh and wind PPAs averaged $29.90 per MWh (see Table 3 in Supplemental Exhibit DSS-2).

Both the Rhudes Creek PPA price and the LevelTen price indexes are used in Supplemental Exhibit DSS-2 to calculate potential avoided capacity costs for solar.

Q. Please summarize the "levelized cost of a CT" methodology from calculating avoided capacity costs.

A. A CT is often thought of as a proxy for capacity cost because it can be quickly started to meet a reliability need any hour of the day throughout the year. Because a CT is available to be dispatched to meet load any hour during the year while intermittent renewable generation technologies are not, the Levelized Cost of a CT methodology requires the avoided capacity price to be adjusted for each generation technology to reflect its ability to meet each month's peak. The adjustment process is described in Supplemental Exhibit DSS-2. Basically, this adjustment process uses each generation technology's projected hourly output as a percentage of nameplate output at the time

[8] LevelTen's quarterly reports are available at the following links:
Q4-2019: https://www.leveltenenergy.com/post/q4-2019
Q1-2020: https://www.leveltenenergy.com/post/q1-2020
Q2-2020: https://www.leveltenenergy.com/post/q2-2020
Q3-2020: https://www.leveltenenergy.com/post/q3-2020
Q4-2020: https://www.leveltenenergy.com/post/q4-2020
Q1-2021: https://www.leveltenenergy.com/post/q1-2021

of the Companies' monthly peak. For example, using this methodology, if a fixed tilt solar facility is expected to be at 59.3 percent of rated output on the day of the August peak, then it would receive 59.3 percent of the CT capacity cost that month. On the other hand, if the same solar plant was at 0.2 percent of rated output at the time of the March peak, then it would receive only 0.2 percent of the CT capacity costs for that month. The sum of the annual capacity revenues is then divided by annual energy (based on the same hourly energy profile used to calculate a technology's avoided energy cost) to produce an annual capacity price per MWh (see Table 10 in Supplemental Exhibit DSS-2).

Q. What is your recommended methodology for calculating avoided capacity costs for the LQF and SQF riders?

A. As described in Supplemental Exhibit DSS-2, I recommend using the lowest cost method for each generation technology. Therefore, I recommend using the Current Market Price methodology based on the Companies' PPA data for solar and the LevelTen Energy index for wind. While both the Current Market Price and the Levelized Cost of a CT methodologies are fundamentally sound, it is important to keep in mind that the customers that are paying for this capacity would prefer the least-cost option. In other words, the only difference between these two methodologies is the underlying technology that is used as the basis for determining the avoided cost of capacity. The Current Market Price methodology indicates that directly using the actual PPA prices for solar and wind technologies would be a lower avoided capacity cost for those technologies than trying to distill this value from a CT. I also recommend using the Companies' own PPA data when available because it is a better indicator of the Companies' own avoided costs than a regional market price index. Thus, I recommend the Current Market Price method using the Companies' PPA data for solar and the LevelTen Energy index for wind, when available, for the purpose of calculating the avoided capacity cost component of the LQF and SQF riders. Only the "other technology" category of LQF and SQF would receive an avoided capacity payment based on the Levelized Cost of a CT methodology because we have no market price data for the technologies in that category.

Q. How are you recommending the Companies determine the volume and timing of avoided capacity?

A. Both the amount of summer capacity needed in the future as well as the potential timing of future capacity needs is the most challenging aspect of determining avoided capacity costs. At this point in time, there are three factors that will impact the Companies' timing and quantity of future summer capacity needs:

1. updated NAAQS NO_x limits for Jefferson County,
2. the end of a generator's economic life, and
3. new environmental laws and/or regulations that would require retirement and replacement of fossil fuel generation.

Given the large uncertainty and wide range of possible new laws and regulations associated with item #3, I am recommending that it be ignored in developing a forecast of future capacity needs. If the Commission accepts the process that I am recommending, changes in laws and regulations that become more concrete (e.g., a federal clean energy standard) can be reflected in future biennial avoided cost filings.

This will help reduce the risk that customers overpay for avoided capacity volumes that turn out not to be avoided because units end up not retiring per the forecast.

Q. Do you have any concerns about using the current market price of wind and solar technologies or the cost of a CT in conjunction with summer reserve margin for determining cost and quantity of avoided capacity?

A. Yes. If, as some predict, the generation fleet over time becomes more dependent on intermittent renewable generation, then the models and parameters for assessing generation resource adequacy will need to change. As was stated in a recent report on the summer 2020 California blackouts by the National Regulatory Research Institute (the research arm of the National Association of Regulatory Utility Commissioners):

> Increasingly, the LOLE and deterministic reserve margin approaches do not fully capture the level of resource adequacy for systems with large amounts of intermittent wind and solar. This is because the LOLE methodology was initially developed to measure the resource adequacy of systems with mostly controllable resources (e.g., large hydro, fossil-fired, and steam powered generators) serving relatively predictable load patterns.[9]

I agree with the statement above, and we have been working on models and analysis that will enable the Companies to better plan for a future with an increasing volume of intermittent generation. However, given our generation fleet at this point in time, I am comfortable that my recommended approach for calculating the cost and quantity of avoided capacity is reasonable.

Q. What is the Companies' future need for capacity?

[9] The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study, Elliot J. Nethercutt and Chris Devon, NRRI Insights, March 2021, page 13.

A. Table 1 in Supplemental Exhibit DSS-2 shows the annual potential summer capacity needs for two scenarios (both assume Mill Creek Unit 1 is retired in 2024):

1. In 2028, NAAQS NO_x regulations in Jefferson County result in the retirement of Mill Creek Unit 2 and Brown Unit 3 reaches the end of its economic life. All other units are assumed to be retired in the year according to the book depreciation life agreed to in this case.
2. All units are retired according to the book depreciation life agreed to in this case in this case.

Since the future is not knowable, I recommend that the annual summer capacity needs in these cases are equally weighted. The resulting average capacity needs are also shown in Table 1 in Supplemental Exhibit DSS-2. For example, Table 1 shows that that Companies' average forecasted summer capacity need is 100 MW in 2028, stepping up to 1,024 MW in 2034 and eventually growing to 5,650 MW by 2045. Note that even though the average capacity need declines slightly from 2028 through 2033, I recommend using the highest need during this period, which is 100 MW, because the need is based on the lowest end of the target summer reserve margin range.

Q. Are you recommending that the Companies procure all of that capacity now and only procure renewable generation?

A. No. As I just mentioned, increasing volumes of intermittent generation capacity in a power system creates a number of issues that grid operators must address in order to ensure grid reliability. The Companies have been studying these renewable integration issues in order to be better prepared for a future with more intermittent generation. It is our strong desire to avoid the recent reliability issues that have faced CAISO, ERCOT, and MISO. The need to ensure grid reliability is why there are various intermittent generation "circuit breakers" in Kentucky such as the legislative caps on net metering capacity and the capacity limits in the Companies' Green Tariff Option #3. Based on the work that we have been doing on renewable integration, it is my recommendation that for now, for LQF and SQF rider purposes, the Companies' future capacity need is limited to the lower of the actual need or 1,000 MW of nameplate QF capacity. For example, even though Table 1 in Supplemental Exhibit DSS-2 shows a 1,024 MW need in 2034, I recommend that it be capped for now at 1,000 MW of nameplate capacity for purposes of paying an avoided capacity payment. If this cap is not in place, then potentially much more renewable generation than 1,024 MW could be added to the system because intermittent renewable generation does not produce at nameplate output at the time of summer peak (see discussion regarding Table 8 in Supplemental Exhibit DSS-2).

Q. How would the Companies' limit on the amount of capacity need impact a QF facility's ability to receive an avoided capacity payment?

A. The system only needs a certain quantity of resources to be reliable, so customers should not pay for more resources than are necessary. The Commission's QF regulation requires QF energy and capacity rates to be based on avoided costs, i.e., customers should only pay for what is being avoided.[10] Because it is unlikely that the Commission would allow the Companies to collect costs of intentionally overbuilding generation, I am assuming the Commission would not want to set QF rates that would result in intentionally over-contracting for generation or paying for capacity that was

[10] *See* 807 KAR 5:054 Section 7(2) and (4).

not needed or that would cause significant integration costs for customers. Therefore, once the capacity need has been met, the avoided generation capacity component of LQF and SQF would become zero for new QFs until capacity needs arise again. This would not limit the ability of any LQF or SQF customer to connect to the system and receive compensation for avoided energy costs. Also, unless a customer enters into a 20-year PPA with a zero avoided capacity component, it would not limit the customer's ability to receive an avoided capacity payment in the future if capacity needs subsequently change.

Q. You said that each generation technology's capacity payment was based on its ability to contribute to monthly peak. Does that concept factor into determining a particular generating technology's contribution to meeting the overall capacity need in a given year?

A. Yes. Table 8 in Supplemental Exhibit DSS-2 shows the contribution to summer peak that is applied to each technology. For example, single axis tracking solar is expected to produce at 78.6 percent of its nameplate rating at the time of summer peak which means that the Companies would be willing to pay an avoided capacity payment for up to 127 MW of nameplate capacity (100 MW summer capacity need in 2028 divided by 0.786) if this was the only technology. However, the overall 1,000 MW limit is based on nameplate capacity rating, not the contribution to summer peak adjusted capacity.

Q. You seem to be recommending that the Companies modify their SQF and LQF riders to use a common set of avoided energy and capacity rates depending on generation technology. Is that correct?

A. Yes. Avoided costs are avoided costs from customers' perspective, so I see no reason why LQF and SQF rates should not be the same when based on a similar technology. Furthermore, this would also simplify administration. To accomplish this, I'm recommending modifying the SQF and LQF riders to incorporate the following concepts regarding avoided energy and capacity rates:

i) The Companies will file new 24-year avoided energy and capacity prices every two years (see Supplemental Exhibit DSS-1 and Supplemental Exhibit DSS-2);

ii) The Companies will file their 24-year need for capacity every two years (see Supplemental Exhibit DSS-2);

iii) Any customer seeking to sell energy and capacity under the SQF or LQF rider during the two-year window between filings that has not already executed a 20-year PPA may (a) choose to execute a 20-year PPA at the prices stated in the Companies' most recent 24-year avoided energy and capacity cost filing or (b) execute a 2-year PPA that resets the capacity and energy prices every two years based on the most recent Companies' filing; and

iv) If the total capacity volume of QF PPAs exceeds the Companies' capacity need, then the avoided capacity price shall be $0 for any volume above the need. This will protect customers from paying for more capacity than they need.

Q. Why are you calculating 24-year avoided energy and capacity costs yet only committing to a 20-year PPA?

A. The 24-year pricing period begins with the soonest year that pricing could be effective after filing with the Commission (e.g., January 2022), while the term of the PPA starts when the QF is commercial and delivers energy to the Companies (e.g., January 2025). Because it may take several years for the QF to get permitted, financed, and constructed, I recommend the Companies provide five years of 20-year levelized pricing to allow the QF up to five years to complete development and enter commercial operations after signing the PPA.

Q. How would your proposal impact existing QFs?

A. I propose that existing QFs be treated as new QFs and be given the same 20-year and 2-year PPA alternatives that I describe above.

Q. Why are you recommending that the Companies' give QFs the opportunity to execute a 20-year PPA?

A. A long-term PPA with a creditworthy utility like LG&E and KU is the basis by which a QF can obtain long-term debt financing. The Companies' experience with its last two generation RFPs shows that a longer term results in lower prices for customers because developers have lower costs and risks. Hence, the ability to execute a long-term PPA at a known energy price will encourage QF development in the Companies' service area by reducing overall project costs and risks.

Q. Are you recommending the same SQF and LQF avoided costs for both Companies?

A. Yes. The Companies jointly plan and dispatch their system and it is my expectation that over time avoided energy and capacity costs would not be materially different between the Companies. This would also simplify administration.

Q. Can you describe an example of how your proposed changes to LQF and SQF would work?

A. Yes. For clarity purposes, I have shown my final recommended LQF and SQF avoided energy and capacity prices in Supplemental Exhibit DSS-3. I will describe two hypotheticals: the choices and prices facing an existing SQF customer with fixed tilt solar technology and the choices and prices facing a potential new LQF customer using single axis tracking solar technology.

The hypothetical existing SQF customer could choose a 2-year or 20-year PPA beginning in 2022 (their 20-year contract can begin in the current year because they are already on the system). Looking at Table 1 and Table 2 in Supplemental Exhibit DSS-3 one sees that a 2-year PPA would mean an energy price of $23.19 per MWh and a capacity price of $0 per MWh. On the other hand, if the SQF was willing to execute a 20-year PPA, Table 1 and Table 2 in Supplemental Exhibit DSS-3 indicate that it would receive $24.07 per MWh for energy and $1.70 per MWh for capacity fixed for the next 20 years.

The hypothetical potential LQF customer would use the same Table 1 and Table 2 in Supplemental Exhibit DSS-3 but would look at the single axis tracking solar technology rows. Also, should this hypothetical customer not be able to get its plant on-line before the end of 2023, it would not know a 2-year PPA price until the Companies made their next biennial avoided cost filing in 2023 for rates effective in 2024 and beyond. Thus, if this potential LQF customer wanted to proceed with their project with known pricing, their only option would be to execute a 20-year PPA and select the pricing based on the year their project would come on-line. For illustrative purposes, I will assume that the project can begin commercial operations in 2024. In that case, the 20-year PPA pricing would be $24.03 per MWh for energy and $2.27 per MWh for capacity – both fixed for 20 years. However, note that if other LQF and SQF customers signed PPAs ahead of this particular LQF such that the 2028 capacity need had been met, then the capacity payment would only be $0.96 per MWh for this new LQF because it would be contributing to only meeting the 2034 need. However, it would receive the $0.96 per MWh beginning in 2024 when the project came on-line.

Q. Does the biennial LQF and SQF avoided cost and capacity need filing with the Commission preclude other generation resource procurement?

A. No. The Companies would continue to plan and procure future generation as we always have, and should there be a potential need for future generation resources, we would issue a capacity RFP (just as we do today). If the RFP process identifies a potential least-cost resource to meet the future need for capacity and energy, then the Companies would seek the appropriate approvals from the Commission (e.g., CPCN). If the new generation resource was approved by the Commission, the Companies would update their future capacity needs for the LQF and SQF riders accordingly.

Section 3 – Net Metering Service

Q. Does your recommended approach to avoided capacity and energy cost differ for NMS-2 customers who supply excess energy to the grid compared to SQF and LQF customers?

A. Because the vast majority of net metered customers employ fixed tilt solar technology, I recommend using the 2-year PPA LQF and SQF avoided energy price for that technology as the avoided energy component of NMS-2 compensation for customers that supply excess energy to the grid. I further recommend that the avoided capacity price for fixed tilt solar technology act as a ceiling to the avoided generation capacity component of NMS-2 compensation; as Mr. Seelye argues in his testimony, the appropriate value for the avoided generation capacity component of NMS-2 compensation is zero.

Q. You said that the avoided energy cost for LQF and SQF does not currently include a value for potential CO_2 and REC costs. Is your recommendation the same for NMS-2 customers?

A. Yes, and for the same reasons as for LQF and SQF. As of now there is no CO_2 price or REC obligation for Kentucky customers so, by definition, there are no costs that customers would avoid if the Companies had to pay NMS-2 customers a value for CO_2 or RECs. As I said, should this change in the future, then the avoided energy cost methodology that I have proposed would reflect such costs. Also, it is my understanding that households can participate in REC markets directly if they are interested in selling their renewable energy attributes to others.

Q. What is your recommendation regarding the avoided environmental compliance cost component of NMS-2 compensation?

A. Based on how I am recommending calculating avoided energy and capacity costs, there is no need for a separate avoided environmental compliance cost component of NMS-2 compensation. There are several reasons for this conclusion. First, as I have already stated, variable environmental compliance costs, i.e., those that vary with energy production, are already accounted for in the avoided energy cost calculations. Second, as I have stated, just as past changes in environmental laws and regulations have caused the Companies to retire generating units and are likely to do so in the future (e.g., Mill

Creek Unit 1 in 2024 and Mill Creek Unit 2 in 2028), these retirements would result in a future capacity need and thus are reflected in the avoided capacity price. Third, certain environmental compliance costs are reflected in capital improvements at a unit (e.g., installation of a new FGD or baghouse) which would be totally unaffected by energy put on the grid by a customer-generator. Thus, adding a separate avoided environmental compliance cost component of NMS-2 compensation is unnecessary and any attempt to manufacture such a cost would add unnecessarily to avoided energy and capacity costs that all customers would have to pay. The proper way to reflect environmental compliance costs is to do it directly in the avoided energy and capacity costs as I have already done.

Section 4 –Recommendation

Q. Please summarize your recommended approach to setting avoided energy and capacity prices for LQF, SQF, and NMS-2 riders.

A. I am recommending that the Companies adopt a consistent method for determining avoided energy and capacity prices for LQF, SQF, and NMS-2 customers that provide them fair compensation for their supply to the grid and ensures that avoided costs are still least-cost for all other customers that are paying for the capacity and energy. This method is easily replicated and should be updated every two years in a filing with Commission to ensure that the SQF and LQF riders are kept up to date with current market information. To determine avoided energy costs, I recommend the Commission approve the use of the output of the Companies' annual long-term business planning process. To determine avoided capacity costs, I recommend the Commission approve the Current Market Price method that is detailed in Supplemental Exhibit DSS-2 because it results in lower costs for all customers while providing the same level of summer capacity. Finally, I recommend that capacity need be determined as described in Supplemental Exhibit DSS-2 but limited to no more than 1,000 MW of nameplate renewable generation at this time. This limit should be reviewed in future biennial avoided cost filings but should always reflect the need to ensure grid reliability at the lowest reasonable cost.

Q. What are the benefits of your recommended changes to NMS-2, SQF, and LQF?

A. My recommended methodology and process for calculating and administering avoided energy and capacity prices for SQF, LQF, and NMS-2 customers has a number of advantages compared to existing rates:

- It treats all generation technologies equitably regardless of size;
- It creates a clear, consistent, repeatable method for calculating avoided energy and capacity prices;
- It is forward looking with long-term certainty which will help promote renewable generation of all types;
- It provides potential and existing SQF and LQF customers with contract term options (2-year or 20-years) that they can choose based on their view of the future and risk profile;
- It calculates avoided energy and capacity prices and determines future capacity needs in a manner that protects the interest of all other customers that must pay the costs associated with the SQF, LQF, and NMS-2 riders;

- By helping to promote renewable energy, the Companies will be able to reduce the use of fossil fuels (e.g., each 80 MW of LQF solar in 2026 would reduce coal burn by approximately 85,000 to 90,000 tons); and
- To the extent customers sign 20-year PPAs, it would reduce customers' future bill volatility by locking in a portion of the future cost of capacity and energy.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of July 2021.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

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. In addition, the 100 MW Rhudes Creek solar project was included as a generation resource beginning January 2023.[1] With these exceptions, all assumptions for computing hourly energy costs were taken from the Companies' 2021 Business Plan ("BP").

In the 2021 BP, Mill Creek Unit 1 was assumed to be retired without replacement in 2024, and Mill Creek Unit 2 and Brown Unit 3 were assumed to be replaced in 2028 with a natural gas combined cycle ("NGCC") unit. All other generating units were assumed to be retired at the end of their depreciable lives and replaced as needed to maintain a minimum 17% summer reserve margin. Coal units were assumed to be replaced with NGCC units and existing simple-cycle combustion turbine ("CT") units were assumed to be replaced with new CT units.

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.[2] Table 1 lists the QF technologies for which avoided energy costs were computed as well as their assumed capacity factors. 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 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 (2022-2045). 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

[1] The status of this project was uncertain when the 2021 BP was completed.
[2] The cost of fuel accounts for approximately 90% of total avoided energy costs.

generation. Not surprisingly, the average avoided cost of energy for wind generation is lower than the solar technologies because wind has more nighttime generation.

Table 2: Avoided Energy Cost ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	23.04	23.33	22.55	22.06
2023	22.83	23.05	22.47	22.02
2024	23.12	23.38	22.81	22.31
2025	23.24	23.49	23.10	22.54
2026	22.64	22.82	22.34	21.90
2027	23.03	23.24	22.80	22.36
2028	22.81	22.95	22.70	22.00
2029	23.24	23.40	23.09	22.42
2030	23.82	23.94	23.72	23.08
2031	24.34	24.48	24.33	23.61
2032	24.89	25.05	24.80	24.11
2033	25.49	25.65	25.46	24.69
2034	25.25	25.49	25.26	24.07
2035	25.76	26.05	25.69	24.52
2036	26.24	26.47	26.15	25.07
2037	26.01	26.29	25.95	24.73
2038	26.07	26.47	25.87	24.65
2039	24.03	24.39	25.19	23.42
2040	23.65	24.05	23.68	22.82
2041	23.45	23.75	23.76	22.82
2042	23.76	24.06	24.15	23.18
2043	24.38	24.67	24.49	23.58
2044	24.81	25.13	25.19	24.10
2045	25.65	26.05	25.56	24.72

To simplify administration, the avoided energy costs in Table 2 were levelized to produce the avoided energy prices shown in Table 3.[3] Table 3 shows the avoided energy prices for a 2-year PPA effective in 2022 through 2024 and for 20-year contracts beginning 2022 through 2026.[4] 2026 is the last year that a customer could enter into a long-term agreement based on these avoided prices.

[3] The levelized cost of energy was computed with the discount rate used to compute the present value of revenue requirements (6.75%).
[4] Avoided energy prices for the 2-year PPA are computed as the average of avoided energy costs in 2022 and 2023.

Table 3: Avoided Energy Costs ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Price for Contracts Beginning:				
		2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Avoided Capacity Cost

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

1 Future Need for Generation Capacity

The Companies' need for future generation capacity depends on load growth and the timing of generating unit retirements. As discussed in Supplemental Exhibit DSS-1, the 2021 BP assumed that Mill Creek Unit 1 would be retired without replacement in 2024, and Mill Creek Unit 2 ("MC2") and Brown Unit 3 ("BR3") would be retired in 2028. Given the uncertainty associated with future environmental regulations, the timing of the MC2 and BR3 retirements is uncertain. Therefore, the Companies computed the future need for generating capacity as the average of two retirement scenarios. In the first scenario, MC2 and BR3 are assumed to be retired in 2028, consistent with the Companies' 2021 BP. In the second scenario, MC2 and BR3 are assumed to be retired in 2034 and 2035, respectively, at the end of their depreciable lives. In both scenarios, all other generating units were assumed to be retired at the end of their depreciable lives.

Table 1 summarizes the Companies' summer capacity need in each scenario as well as the average summer capacity need. Table 15 and Table 16 in Appendix A provide a detailed summary of the Companies' summer peak demand forecast, unit retirement assumptions, and summer capacity need for each scenario.

Table 1: Summer Capacity Need (MW)

Year	Scenario 1: 2021 BP	Scenario 2: End of Depreciable Life	Average of Scenarios 1 and 2
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	199	0	100
2029	188	0	94
2030	173	0	87
2031	160	0	80
2032	152	0	76
2033	154	0	77
2034	1,230	818	1,024
2035	1,473	1,473	1,473
2036	1,595	1,595	1,595
2037	2,556	2,556	2,556
2038	2,561	2,561	2,561
2039	3,723	3,723	3,723
2040	3,876	3,876	3,876
2041	4,184	4,184	4,184
2042	4,658	4,658	4,658
2043	4,739	4,739	4,739
2044	5,214	5,214	5,214
2045	5,650	5,650	5,650

2 Avoided Capacity Cost

The Companies used two methods to compute avoided capacity costs:

1. Current Market Price
2. Levelized Cost of a Simple Cycle Combustion Turbine (“CT”)

Because generating technologies have different energy performance capabilities, the Companies used both of these methods to develop avoided capacity costs for the following technologies:

1. single axis tracking solar,
2. fixed tilt solar,
3. wind,
4. other technologies (e.g., cogeneration facility with a steam host, hydro, biomass).

Due to a lack of market data, only the Levelized Cost of a CT method was used for the “other technology” category.

The Current Market Price method uses technology specific PPA prices to directly calculate annual avoided capacity prices. This is done by subtracting each technology's avoided energy cost from the PPA price.[1] While this difference is not really the value of capacity, the only reason that customers should be willing to pay more than avoided energy cost is because they see some additional value from the PPA. For the purposes of this method, that value is assumed to be capacity.

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.

After avoided capacity costs are determined for each method, the least-cost method was selected to calculate the avoided capacity payment for each technology by zeroing out any values in a year when there is no capacity need. These annual values are then levelized in order to determine the final 2-year and 20-year avoided capacity payments.

2.1 Current Market Price

Ideally, market prices should be based on current transactions. However, when markets are thinly traded or volatile, it can be necessary to average transactions to get a better sense of market prices. The Companies have one recent solar PPA (with Rhudes Creek executed in the fourth quarter of 2019) and no wind PPAs. Thus, the Companies sought a third-party source for renewable PPAs and came across the LevelTen Energy PPA Price Index. LevelTen Energy collects PPA price information quarterly for RTOs across the nation. However, given the volatility of the quarterly data and to be consistent with the date the Rhudes Creek PPA was executed, the Companies averaged the prices in PJM and MISO since the fourth quarter of 2019 to develop a unique market price for wind and solar. The Companies also used the Rhudes Creek PPA price for solar technologies. Thus, the Companies were able to develop two avoided capacity costs for solar – one based on the Rhudes Creek PPA and the other based on the LevelTen Energy data.

2.1.1 Rhudes Creek Solar Project

The cost of energy for the Rhudes Creek solar project is $27.82/MWh over a 20-year term with no escalation. The Rhudes Creek project utilizes bifacial solar panels with single-axis tracking technology. This technology provides the most cost-effective means of procuring solar power for customers and is, therefore, used to compute avoided capacity costs for all solar technologies. In Table 2, the avoided capacity value for each solar technology is computed as the difference between the Rhudes Creek energy cost and the avoided cost of energy in Table 2 of Supplemental Exhibit DSS-1.

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[1] Table 2 in Supplemental Exhibit DSS-1 contains each technology's avoided energy cost.

Table 2: Rhudes Creek Solar Cost less Avoided Energy Costs ($/MWh)

Year	Rhudes Creek Solar	Avoided Energy Cost		Avoided Capacity Value: Rhudes Creek Solar less Avoided Energy Cost	
		Solar: Single-Axis Tracking	Solar: Fixed Tilt	Solar: Single-Axis Tracking	Solar: Fixed Tilt
2022	27.82	23.04	23.33	4.78	4.49
2023	27.82	22.83	23.05	4.99	4.77
2024	27.82	23.12	23.38	4.70	4.44
2025	27.82	23.24	23.49	4.58	4.33
2026	27.82	22.64	22.82	5.18	5.00
2027	27.82	23.03	23.24	4.79	4.58
2028	27.82	22.81	22.95	5.01	4.87
2029	27.82	23.24	23.40	4.58	4.42
2030	27.82	23.82	23.94	4.00	3.88
2031	27.82	24.34	24.48	3.48	3.34
2032	27.82	24.89	25.05	2.93	2.77
2033	27.82	25.49	25.65	2.33	2.17
2034	27.82	25.25	25.49	2.57	2.33
2035	27.82	25.76	26.05	2.06	1.77
2036	27.82	26.24	26.47	1.58	1.35
2037	27.82	26.01	26.29	1.81	1.53
2038	27.82	26.07	26.47	1.75	1.35
2039	27.82	24.03	24.39	3.79	3.43
2040	27.82	23.65	24.05	4.17	3.77
2041	27.82	23.45	23.75	4.37	4.07
2042	27.82	23.76	24.06	4.06	3.76
2043	27.82	24.38	24.67	3.44	3.15
2044	27.82	24.81	25.13	3.01	2.69
2045	27.82	25.65	26.05	2.17	1.77

2.1.2 LevelTen Energy PPA Price Index

Each quarter, the LevelTen Energy PPA Price Index reports the prices that wind and solar project developers have offered for PPAs in various RTOs across the nation. Table 3 contains solar and wind PPA prices from the LevelTen report from Q4-2019 through Q1-2021.[2] The average of solar PPA prices

[2] LevelTen's quarterly reports are available at the following links:
Q4-2019: https://www.leveltenenergy.com/post/q4-2019
Q1-2020: https://www.leveltenenergy.com/post/q1-2020
Q2-2020: https://www.leveltenenergy.com/post/q2-2020
Q3-2020: https://www.leveltenenergy.com/post/q3-2020
Q4-2020: https://www.leveltenenergy.com/post/q4-2020
Q1-2021: https://www.leveltenenergy.com/post/q1-2021

in MISO and PJM over this period was $32.96/MWh. For wind, the average was $29.90/MWh. All PPA pricing is flat with no escalation over a 10-15 year term.

Table 3: LevelTen Energy PPA Price Index ($/MWh)[3]

	Solar				Wind		
	MISO	**PJM**	**Average**		**MISO**	**PJM**	**Average**
Q4-2019	28.50	32.70	30.60		24.90	26.00	25.45
Q1-2020	29.60	32.90	31.25		25.50	27.60	26.55
Q2-2020	29.00	33.00	31.00		23.30	33.50	28.40
Q3-2020	31.20	36.80	34.00		30.00	35.60	32.80
Q4-2020	33.70	37.50	35.60		33.00	35.50	34.25
Q1-2021	34.60	36.00	35.30		28.40	35.50	31.95
Average	**31.10**	**34.82**	**32.96**		**27.52**	**32.28**	**29.90**

In Table 4, the avoided capacity value for each solar technology is computed as the difference between the average LevelTen solar PPA price and the avoided cost of energy in Table 2 of Supplemental Exhibit DSS-1.

[3] LevelTen provided 10th percentile PPA pricing for each RTO for Q4-2019 through Q2-2020 and 25th percentile pricing for each RTO for Q3-2020 through Q1-2021.

Table 4: LevelTen Solar PPA Index less Avoided Energy Costs ($/MWh)

Year	LevelTen Solar PPA Index[4]	Avoided Energy Cost		Avoided Capacity Value: LevelTen Solar PPA Index less Avoided Energy Cost	
		Solar: Single-Axis Tracking	Solar: Fixed Tilt	Solar: Single-Axis Tracking	Solar: Fixed Tilt
2022	32.96	23.04	23.33	9.92	9.63
2023	32.96	22.83	23.05	10.13	9.91
2024	32.96	23.12	23.38	9.84	9.58
2025	32.96	23.24	23.49	9.72	9.47
2026	32.96	22.64	22.82	10.32	10.14
2027	32.96	23.03	23.24	9.93	9.72
2028	32.96	22.81	22.95	10.15	10.01
2029	32.96	23.24	23.40	9.72	9.56
2030	32.96	23.82	23.94	9.14	9.02
2031	32.96	24.34	24.48	8.62	8.48
2032	32.96	24.89	25.05	8.07	7.91
2033	32.96	25.49	25.65	7.47	7.31
2034	32.96	25.25	25.49	7.71	7.47
2035	32.96	25.76	26.05	7.20	6.91
2036	32.96	26.24	26.47	6.72	6.49
2037	32.96	26.01	26.29	6.95	6.67
2038	32.96	26.07	26.47	6.89	6.49
2039	32.96	24.03	24.39	8.93	8.57
2040	32.96	23.65	24.05	9.31	8.91
2041	32.96	23.45	23.75	9.51	9.21
2042	32.96	23.76	24.06	9.20	8.90
2043	32.96	24.38	24.67	8.58	8.29
2044	32.96	24.81	25.13	8.15	7.83
2045	32.96	25.65	26.05	7.31	6.91

In Table 5, the avoided capacity value for the wind technology is computed as the difference between the average LevelTen wind PPA price and the avoided cost of energy in Table 2 of Supplemental Exhibit DSS-1.

[4] $32.96/MWh is the average of solar PPA prices in MISO and PJM from Q4-2019 through Q1-2021.

Table 5: LevelTen Wind PPA Index less Avoided Energy Costs ($/MWh)

Year	LevelTen Wind PPA Index[5]	Avoided Energy Cost: Wind	Avoided Capacity Value: LevelTen Wind PPA Index less Avoided Energy Cost
2022	29.90	22.55	7.35
2023	29.90	22.47	7.43
2024	29.90	22.81	7.09
2025	29.90	23.10	6.80
2026	29.90	22.34	7.56
2027	29.90	22.80	7.10
2028	29.90	22.70	7.20
2029	29.90	23.09	6.81
2030	29.90	23.72	6.18
2031	29.90	24.33	5.57
2032	29.90	24.80	5.10
2033	29.90	25.46	4.44
2034	29.90	25.26	4.64
2035	29.90	25.69	4.21
2036	29.90	26.15	3.75
2037	29.90	25.95	3.95
2038	29.90	25.87	4.03
2039	29.90	25.19	4.71
2040	29.90	23.68	6.22
2041	29.90	23.76	6.14
2042	29.90	24.15	5.75
2043	29.90	24.49	5.41
2044	29.90	25.19	4.71
2045	29.90	25.56	4.34

2.2 Levelized Cost of a CT

CT units are available around-the-clock and designed for fast starts and load following. As a result, CT capacity is oftentimes viewed as the purest form of capacity. Table 6 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 2020 Annual Technology Baseline.[6] Firm gas transportation costs are based on the Companies' cost of firm gas transportation for the Trimble County CTs.

[5] $29.90/MWh is the average of wind PPA prices in MISO and PJM from Q4-2019 through Q1-2021.

[6] Source: https://data.nrel.gov/submissions/145.

Table 6: CT Capital and Fixed Operating Costs

Cost	2028 Installation (Real 2018 $)	2028 Installation (Nominal $)	Escalation
Overnight Capital ($/kW)	869	1,059	1.66%
Fixed O&M ($/kW-Year)	11.39	13.89	2.0%
Firm Gas Transportation ($/kW-Year)	N/A	25.47	2.0%

Table 7 contains the economic carrying charge for a CT, based on the cost and escalation assumptions in Table 6. 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 8 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. Note that "other technologies" are assumed to be 100 percent available to meet monthly peak load.

Table 7: CT Economic Carrying Charge ($/MW-Year)

Year	CT Economic Carrying Charge
2022	106,487
2023	108,372
2024	110,291
2025	112,244
2026	114,231
2027	116,255
2028	118,314
2029	120,410
2030	122,544
2031	124,715
2032	126,926
2033	129,176
2034	131,466
2035	133,797
2036	136,170
2037	138,585
2038	141,043
2039	143,546
2040	146,093
2041	148,686
2042	151,325
2043	154,011
2044	156,746
2045	159,529

Table 8: 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 9, annual avoided costs are computed for each generation technology by multiplying the CT costs in Table 7 by the average annual availability factors in Table 8 (i.e., 37.2% for single-axis tracking solar, 28.8% for fixed tilt solar, and so on).

Table 9: Annual Avoided Capacity Costs Based on CT Cost ($/MW-Year)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	39,633	30,669	30,516	106,487
2023	40,335	31,212	31,056	108,372
2024	41,049	31,764	31,606	110,291
2025	41,776	32,327	32,166	112,244
2026	42,516	32,899	32,735	114,231
2027	43,269	33,482	33,315	116,255
2028	44,035	34,075	33,905	118,314
2029	44,815	34,679	34,506	120,410
2030	45,609	35,293	35,117	122,544
2031	46,418	35,919	35,740	124,715
2032	47,240	36,555	36,373	126,926
2033	48,078	37,203	37,018	129,176
2034	48,930	37,863	37,674	131,466
2035	49,798	38,534	38,342	133,797
2036	50,681	39,218	39,022	136,170
2037	51,580	39,913	39,714	138,585
2038	52,495	40,621	40,419	141,043
2039	53,426	41,342	41,136	143,546
2040	54,374	42,076	41,866	146,093
2041	55,339	42,823	42,609	148,686
2042	56,322	43,583	43,365	151,325
2043	57,321	44,356	44,135	154,011
2044	58,339	45,144	44,919	156,746
2045	59,375	45,946	45,717	159,529

To compute avoided capacity costs on a $/MWh basis, the annual values in Table 9 were divided by each technology's expected generation (see Table 10). The assumed capacity factors for each technology are listed in Table 1 of Supplemental Exhibit DSS-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 10: Avoided Capacity Costs Based on CT Cost ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	17.43	20.99	13.75	12.16
2023	17.74	21.36	13.99	12.37
2024	18.05	21.74	14.24	12.59
2025	18.37	22.13	14.49	12.81
2026	18.70	22.52	14.75	13.04
2027	19.03	22.92	15.01	13.27
2028	19.37	23.32	15.27	13.51
2029	19.71	23.74	15.54	13.75
2030	20.06	24.16	15.82	13.99
2031	20.42	24.58	16.10	14.24
2032	20.78	25.02	16.39	14.49
2033	21.15	25.46	16.68	14.75
2034	21.52	25.92	16.97	15.01
2035	21.90	26.37	17.27	15.27
2036	22.29	26.84	17.58	15.54
2037	22.69	27.32	17.89	15.82
2038	23.09	27.80	18.21	16.10
2039	23.50	28.30	18.53	16.39
2040	23.91	28.80	18.86	16.68
2041	24.34	29.31	19.19	16.97
2042	24.77	29.83	19.54	17.27
2043	25.21	30.36	19.88	17.58
2044	25.66	30.90	20.24	17.89
2045	26.11	31.45	20.59	18.21

2.3 Recommended Avoided Capacity Costs

Consistent with least-cost principles, the recommended avoided capacity costs for each technology are contained in Table 11. Because the LevelTen Energy avoided capacity values for solar are higher than the Rhudes Creek avoided capacity values, the Companies recommend using the Rhudes Creek values for the solar technologies. In the absence of Company-specific wind PPA data, the Companies recommend using the LevelTen Energy avoided capacity values for wind because they are lower cost than the capacity values computed based on the cost of a CT. Finally, the recommended avoided cost values for other technologies are computed based on the avoided cost of a CT. The Companies do not have PPA or index prices for the other technologies.

Table 11: Recommended Avoided Capacity Costs ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	4.78	4.49	7.35	12.16
2023	4.99	4.77	7.43	12.37
2024	4.70	4.44	7.09	12.59
2025	4.58	4.33	6.80	12.81
2026	5.18	5.00	7.56	13.04
2027	4.79	4.58	7.10	13.27
2028	5.01	4.87	7.20	13.51
2029	4.58	4.42	6.81	13.75
2030	4.00	3.88	6.18	13.99
2031	3.48	3.34	5.57	14.24
2032	2.93	2.77	5.10	14.49
2033	2.33	2.17	4.44	14.75
2034	2.57	2.33	4.64	15.01
2035	2.06	1.77	4.21	15.27
2036	1.58	1.35	3.75	15.54
2037	1.81	1.53	3.95	15.82
2038	1.75	1.35	4.03	16.10
2039	3.79	3.43	4.71	16.39
2040	4.17	3.77	6.22	16.68
2041	4.37	4.07	6.14	16.97
2042	4.06	3.76	5.75	17.27
2043	3.44	3.15	5.41	17.58
2044	3.01	2.69	4.71	17.89
2045	2.17	1.77	4.34	18.21

3 Calculation of Avoided Capacity Prices

As noted previously, the avoided capacity price for a given technology is computed as a function of the Companies' future need for generation capacity and the cost of avoided capacity. A 20-year QF contract beginning 2024 would defer the need for capacity in 2028 by 16 years to 2044. Similarly, the same contract would defer a 2034 capacity need by only 10 years. The sooner the capacity need, the higher the avoided capacity value. Table 12 lists the avoided capacity costs for each technology associated with a 20-year contract beginning in 2024. The first section in Table 12 contains avoided capacity costs associated with a 2028 capacity need; the second section contains avoided capacity costs associated with a 2034 capacity need.

Table 12: Avoided Capacity Costs for 20-Year Contract Beginning 2024 ($/MWh)

	Avoided Capacity Costs for 2028 Capacity Need				Avoided Capacity Costs for 2034 Capacity Need			
Year	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	5.01	4.87	7.20	13.51	-	-	-	-
2029	4.58	4.42	6.81	13.75	-	-	-	-
2030	4.00	3.88	6.18	13.99	-	-	-	-
2031	3.48	3.34	5.57	14.24	-	-	-	-
2032	2.93	2.77	5.10	14.49	-	-	-	-
2033	2.33	2.17	4.44	14.75	-	-	-	-
2034	2.57	2.33	4.64	15.01	2.57	2.33	4.64	15.01
2035	2.06	1.77	4.21	15.27	2.06	1.77	4.21	15.27
2036	1.58	1.35	3.75	15.54	1.58	1.35	3.75	15.54
2037	1.81	1.53	3.95	15.82	1.81	1.53	3.95	15.82
2038	1.75	1.35	4.03	16.10	1.75	1.35	4.03	16.10
2039	3.79	3.43	4.71	16.39	3.79	3.43	4.71	16.39
2040	4.17	3.77	6.22	16.68	4.17	3.77	6.22	16.68
2041	4.37	4.07	6.14	16.97	4.37	4.07	6.14	16.97
2042	4.06	3.76	5.75	17.27	4.06	3.76	5.75	17.27
2043	3.44	3.15	5.41	17.58	3.44	3.15	5.41	17.58

To compute the avoided cost price for a 20-year contract beginning in 2024, the Companies levelized the values in Table 12 over the period 2024 to 2043. Table 13 contains the results of this calculation.

Table 13: Levelized Avoided Capacity Price for 20-Year Contract beginning in 2024 ($/MWh)

	Avoided Capacity Costs for 2028 Capacity Need				Avoided Capacity Costs for 2034 Capacity Need			
Year	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other
2024-2043	2.27	2.12	3.68	10.33	0.96	0.86	1.63	5.51

This calculation was completed for each technology and each year a 20-year contract can begin (2022 through 2026). The final results are summarized in Table 14.

Table 14: Recommended Avoided Capacity Prices ($/MWh)

Avoided Capacity Price for 2028 Capacity Need						
	2-Year PPA (2021-2023)	**20-Year Level Price for Contracts Beginning:**				
Technology		**2022**	**2023**	**2024**	**2025**	**2026**
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71
Avoided Capacity Price for 2034 Capacity Need						
	2-Year PPA (2021-2023)	**20-Year Level Price for Contracts Beginning:**				
Technology		**2022**	**2023**	**2024**	**2025**	**2026**
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

The Companies' summer peak demand typically occurs in June, July, or August. Because solar and wind resources are not fully available during the peak hour in these months, the maximum amount of nameplate capacity eligible for an avoided capacity payment is computed by dividing the average capacity need in Table 1 by the QF resource's average summer availability in Table 8. For example, if 400 MW of single-axis tracking solar was added to the Companies' system in 2023, only the first 127 MW added would be eligible for an avoided capacity payment associated with deferring the summer capacity need in 2028.[7] The balance of the 400 MW would be eligible for an avoided capacity payment associated with deferring the summer capacity need in 2034.

[7] 127 MW is computed by dividing the average 2028 summer capacity need (100 MW in Table 1) by the summer average availability for single-axis tracking solar (78.6% in Table 2).

4 Appendix A

Table 15: Reserve Margin Need Assuming MC2, BR3 Retirements in 2028 (Scenario 1)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	6,139	6,130	6,123	6,109	6,095	6,080	6,058	6,047	6,033	6,021	6,013	6,014	6,009	6,009	6,009	6,010	6,013	6,014	6,014	6,014	6,010	6,011	6,009	6,010
Resources	7,686	7,686	7,686	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DLC	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43	42	41	40	39	39	38	37	37	36
MC NO_x Reduction	(297)	(297)	(297)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PPA	-	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	-	-	-
Resources Before Ret.	7,577	7,655	7,653	7,949	7,948	7,946	7,945	7,943	7,942	7,941	7,940	7,939	7,938	7,937	7,936	7,935	7,934	7,933	7,932	7,932	7,931	7,851	7,851	7,850
Retirements																								
Small CTs [8]	-	-	-	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)
MC1	-	-	-	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
MC2	-	-	-	-	-	-	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
BR3	-	-	-	-	-	-	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
GH1-2	-	-	-	-	-	-	-	-	-	-	-	-	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)
BR9	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
BR8, 10	-	-	-	-	-	-	-	-	-	-	-	-	-	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)
BR11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
GH3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)
MC3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(868)	(868)	(868)	(868)	(868)	(868)	(868)
BR6-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(292)	(292)	(292)	(292)	(292)	(292)	(292)
OVEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(152)	(152)	(152)	(152)	(152)	(152)
BR5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(130)	(130)	(130)	(130)	(130)
PR13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(147)	(147)	(147)	(147)	(147)
Dix 1-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	(32)	(32)	(32)	(32)
TC5-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)	(477)	(477)
TC8-10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)
TC1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(370)
Ohio Falls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(64)
Total Ret.	-	-	-	(347)	(347)	(347)	(1,056)	(1,056)	(1,056)	(1,056)	(1,056)	(1,056)	(2,137)	(2,379)	(2,500)	(3,459)	(3,459)	(4,619)	(4,771)	(5,080)	(5,557)	(5,557)	(6,034)	(6,468)
Resources Net of Ret.	7,577	7,655	7,653	7,602	7,601	7,599	6,889	6,887	6,886	6,885	6,884	6,883	5,801	5,558	5,436	4,476	4,475	3,314	3,161	2,852	2,374	2,294	1,817	1,382
17% Reserve Margin Need	**-**	**-**	**-**	**-**	**-**	**-**	**199**	**188**	**173**	**160**	**152**	**154**	**1,230**	**1,473**	**1,595**	**2,556**	**2,561**	**3,723**	**3,876**	**4,184**	**4,658**	**4,739**	**5,214**	**5,650**

[8] Haefling 1-2 and Paddy's Run 12

Table 16: Reserve Margin Need Assuming MC2, BR3 Retire at End of Depreciable Life (Scenario 2)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	6,139	6,130	6,123	6,109	6,095	6,080	6,058	6,047	6,033	6,021	6,013	6,014	6,009	6,009	6,009	6,010	6,013	6,014	6,014	6,014	6,010	6,011	6,009	6,010
Resources	7,686	7,686	7,686	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DLC	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43	42	41	40	39	39	38	37	37	36
MC NO_x Reduction	(297)	(297)	(297)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PPA	-	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	-	-	-
Resources Before Ret.	7,577	7,655	7,653	7,949	7,948	7,946	7,945	7,943	7,942	7,941	7,940	7,939	7,938	7,937	7,936	7,935	7,934	7,933	7,932	7,932	7,931	7,851	7,851	7,850
Retirements																								
Small CTs [9]	-	-	-	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)
MC1	-	-	-	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
MC2	-	-	-	-	-	-	-	-	-	-	-	-	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
BR3	-	-	-	-	-	-	-	-	-	-	-	-	-	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
GH1-2	-	-	-	-	-	-	-	-	-	-	-	-	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)
BR9	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
BR8, 10	-	-	-	-	-	-	-	-	-	-	-	-	-	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)
BR11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
GH3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)
MC3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(868)	(868)	(868)	(868)	(868)	(868)	(868)
BR6-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(292)	(292)	(292)	(292)	(292)	(292)	(292)
OVEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(152)	(152)	(152)	(152)	(152)	(152)
BR5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(130)	(130)	(130)	(130)	(130)
PR13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(147)	(147)	(147)	(147)	(147)
Dix 1-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	(32)	(32)	(32)	(32)
TC5-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)	(477)	(477)
TC8-10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)
TC1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(370)
Ohio Falls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(64)
Total Ret.	-	-	-	(347)	(347)	(347)	(347)	(347)	(347)	(347)	(347)	(347)	(1,725)	(2,379)	(2,500)	(3,459)	(3,459)	(4,619)	(4,771)	(5,080)	(5,557)	(5,557)	(6,034)	(6,468)
Resources Net of Ret.	7,577	7,655	7,653	7,602	7,601	7,599	7,598	7,596	7,595	7,594	7,593	7,592	6,213	5,558	5,436	4,476	4,475	3,314	3,161	2,852	2,374	2,294	1,817	1,382
17% Reserve Margin Need	-	-	-	-	-	-	-	-	-	-	-	-	**818**	**1,473**	**1,595**	**2,556**	**2,561**	**3,723**	**3,876**	**4,184**	**4,658**	**4,739**	**5,214**	**5,650**

[9] Haefling 1-2 and Paddy's Run 12

Recommended LQF and SQF Rates

Table 1: Avoided Energy Price ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Price for Contracts Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Table 2: Avoided Capacity Price ($/MWh)

Avoided Capacity Price for 2028 Capacity Need						
Technology	**2-Year PPA (2021-2023)**	**20-Year Level Price for Contracts Beginning: 2022**	**2023**	**2024**	**2025**	**2026**
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71
Avoided Capacity Price for 2034 Capacity Need						
Technology	**2-Year PPA (2021-2023)**	**20-Year Level Price for Contracts Beginning: 2022**	**2023**	**2024**	**2025**	**2026**
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, 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**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS 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. 2020-00350**

SUPPLEMENTAL DIRECT TESTIMONY OF
JOHN K. WOLFE
VICE PRESIDENT, ELECTRIC DISTRIBUTION
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: July 13, 2021

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I. INTRODUCTION AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is John K. Wolfe. I am Vice President of Electric Distribution for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. I discuss the appropriate approach to calculating avoided distribution cost for net metering. Also, I respond to certain statements made in the Commission's June 30, 2021 orders in these proceedings concerning the Companies' actual and potential distribution investments and how they relate to net metering.

II. CALCULATING AVOIDED DISTRIBUTION CAPACITY COST

Q. What is an appropriate conceptual framework for determining avoided distribution capacity cost arising from net metering?

A. An appropriate conceptual framework for determining avoided distribution capacity cost arising from net metering must include the following:

1. It must consider future investments, not embedded costs. There is no amount of net metering that can change investments already made. Therefore, an accurate framework will consider only future investments.
2. It must recognize that distribution components are sized to serve anticipated peak loads and power flows, which can occur at different seasons and times of day for different distribution system components. Therefore, *when* net metering

customers' generation can produce net energy onto the Companies' systems is highly relevant, and particularly whether that net production regularly coincides with distribution system components' peak loads.

3. It must recognize that the location of energy exports that affect distribution system components affects either the cost or benefit of those exports. Because the Companies do not plan or choose where net metering customers will locate, what kinds and sizes of facilities they will choose, or when the conditions will be right for actual energy production to occur, this adds considerable uncertainty regarding the impact net metering can have on future distribution capacity investments.

4. It must consider distribution system reliability. Distribution components must perform reliably across a wide range of operating conditions every hour of the year, not just when the sun is shining on a hot day. This includes a broad array of environmental conditions and system conditions and contingencies—including the contingency that net metered generating sources might not perform as expected. Therefore, the dispatchability, intermittency, and reliability of net metering customers' generators must be taken into account.

5. It must account for the limited and necessarily distributed nature of net metering. KRS 278.466(1) limits each utility's obligation to offer net metering service when the utility's aggregate net metering capacity reaches 1% of the utility's annual peak load. Also, net metering generating facilities are necessarily distributed rather than concentrated due to customer choice and the requirements of the Commission's Net Metering Interconnection Guidelines.[1] For example, the Guidelines state, "For

[1] *See, e.g.*, *Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity up to Thirty Kilowatts*, Case No. 2008-00169, Order Appx. A at 3 (Ky. PSC Jan. 8, 2009).

interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load."[2] It is my understanding that the Guidelines were drafted to ensure net metering would have no appreciable impact on the distribution system. This approach limits (or ideally eliminates) cost incurrence related to net metering, but it also limits (and likely eliminates) savings creation.

6. It must account for the portion of the distribution system that does not vary with demand or does not vary with small changes in demand associated with net exports from net metering customers. And it is important to note that the portion of net metering output that is relevant here is *net exports*, not the gross output or capacity of net metering systems. The only question to address here is how much distribution capacity cost, if any, can net exports from net metering customers avoid.

Although this framework may not be entirely exhaustive, including these items will help ensure a reasonable and accurate assessment of avoided distribution capacity costs resulting from net metering.

I would also observe that new load-based investments for new substations, expansion of distribution lines, and installation of service lines are not impacted by net metering customers because the referenced new infrastructure is required to deliver energy to associated new customers irrespective of net metering resources being exported to the grid.

[2] *Id*.

Q. Using this conceptual framework, have the Companies identified any avoided distribution capacity cost that net metering has created to date?

A. No. The Companies have reviewed past and currently planned capacity-based investments for its distribution system and have not identified any that have been or can be avoided due to net metering resources currently or forecasted to be interconnected to the distribution system during the current planning horizon. That result is unsurprising: none of the Companies' substation transformers has connected net metering capacity exceeding 3% of the transformer's peak loading.

For additional context, KU net metering customers' aggregate capacity is only about 0.2% of KU's system peak load and is spread across nearly 40% of KU's substation transformers, and only 1.4% of KU substation transformers (i.e., seven transformers out of 491 total) have connected net metering capacity of greater than 1% of substation transformer capacity.[3] Moreover, of KU's 40 transformer replacements from 2016-2021, only one transformer had greater than 1% net metering capacity connected to it. It failed in service and was replaced in kind.

Similarly, LG&E net metering customers' aggregate capacity is about 0.25% of LG&E's system peak load and is spread across nearly 60% of LG&E's substation transformers, and only 2.8% of LG&E substation transformers (i.e., four transformers out of 143 total) have connected net metering capacity of greater than 1% of substation transformer capacity.[4] Of LG&E's three transformer replacements in the last 5 years, none of the transformers had greater than 0.25% net metering capacity connected to it; all replacements were due to in-service failure.

[3] KU Response to PSC 6-9.
[4] LG&E Response to PSC 6-9.

In addition to the truly distributed nature of net metering so far in the Companies' service territories, the timing of system peaks leads me to conclude it is likely that net metering will lead to only negligible avoided distribution capacity cost in the foreseeable future, particularly on KU's system. KU is a dual-peaking system because so many of KU's customers use electricity for heat. For example, in calendar year 2020, KU's 2020 Kentucky-only peak of 3,500 MW occurred in the 2:00 – 3:00 p.m. hour on July 21, 2020; the KU total system load in that hour was 3,571 MW. But KU's 2020 total system peak of 3,642 MW occurred in the 7:00 – 8:00 a.m. hour on January 22, 2020, when KU's Kentucky-only load was 3,483 MW. Notably, sunrise did not occur until 7:50 a.m. in Lexington, Kentucky that day, making it unlikely that distributed generation provided any material amount of energy at the time of KU's 2020 system peak.[5] Indeed, the Companies' Brown Solar facility was a net consumer of electricity in that hour.[6]

For the LG&E system, the 2020 system annual peak of 2,505 MW occurred in the 3:00 – 4:00 p.m. hour on July 21. In that hour, the output of the Companies' Brown Solar facility ranged from 6,025 kW to 8,344 kW and averaged 7,697 kW—less than 80% of its peak output. The next hour was LG&E's second-highest demand of 2020: 2,504 MW. During that hour, the output of the Companies' Brown Solar facility ranged from 858 kW to 7,183 kW and averaged 5,063 kW—about half of its peak output. Finally, the next hour was LG&E's fourth-highest demand of 2020: 2,482 MW. During that hour, the output of the Companies' Brown Solar facility ranged from 871 kW to

[5] Sunrise data obtained from https://sunrise-sunset.org/us/lexington-ky/2020/1 (accessed July 7, 2021).
[6] Minute-by-minute historical production data for the Brown Solar Facility is available at: https://lge-ku.com/live-solar-generation/historical-data.

4,660 kW and averaged 3,019 kW—about 30% of its peak output. This data shows that even for LG&E, which is an unambiguously summer-peaking utility, peak demands and peak solar production do not necessarily coincide, and solar production can be highly variable even during peak hours.

I raise these points to illustrate the operational realities the Companies must account for when planning their systems, including their distribution systems. In light of data like this, as well as data the Companies analyze on a circuit-by-circuit and nearly second-by-second basis, it is my professional opinion that it is unlikely the Companies will actually avoid any distribution cost associated with net metering, and more specifically *net metering energy exports*, the latter of which is the only relevant quantity for each utility to consider in formulating an avoided distribution capacity component for NMS-2 export rates.

Q. Notwithstanding that net metering has not yet created any avoided distribution capacity cost for the Companies and their customers, what is an appropriate methodology for calculating potential avoided distribution capacity cost that might arise from net metering?

A. Mr. Seelye presents in his supplemental testimony an approach to calculating avoided distribution capacity cost resulting from net metering that is consistent with the six-point framework I articulated above. It considers only planned and projected future capacity-based distribution investments. It further accounts for the degree to which net metering customers' generating facilities, which are almost exclusively solar photovoltaic systems, are intermittent and the degree to which they tend to produce net energy during the Companies' respective peaks.

What Mr. Seelye's methodology does not do is account for the step-wise nature of distribution investments (which are instead modeled as straight-line cost curves) and the locational impacts of net metering and timing of its production relative to loading on the system, either positive or negative. Instead, for the sake of simplicity, Mr. Seelye's model assumes all net metering exports contribute to avoided distribution capacity costs, regardless of the size or location of the exports. These simplifications are necessary due to time and complexity constraints, and they result in more favorable avoided distribution capacity cost values for net metering customers. These observations aside, Mr. Seelye's calculation methodology is reasonable.

Q. Applying the Companies' proposed calculation methodology, what is the maximum reasonable avoided distribution capacity cost for which the Companies' net metering customers could be compensated?

A. As Mr. Seelye explains in his testimony, the maximum reasonable avoided distribution capacity cost component of NMS-2 for KU is $0.00046/kWh and $0.00012/kWh for LG&E. I say these are the maximum reasonable amounts because it remains my professional opinion that there have been and likely will be no avoided distribution capacity costs resulting from net metering during the current planning horizon. That aside, I believe Mr. Seelye's methodology and calculations are reasonable, and the values he has calculated for avoided distribution capacity cost can serve as reasonable maximum values under current conditions and projections.

III. PURPOSES OF THE COMPANIES' DISTRIBUTION INVESTMENTS

Q. The Commission's June 30, 2021 orders in these proceedings giving rise to this testimony state regarding a variety of the Companies' current or anticipated distribution investments, "[A] primary purpose of much of this investment is to

accommodate a dynamic distribution system, particularly one with increasing penetrations of distributed resources."[7] The orders further state, "Additionally, the basis for some of these investments, such as voltage regulation, can be accomplished by other means like distributed resources."[8] Would you like to comment on this statement?

A. Yes. The Companies' current, planned, or contemplated technology investments all have the primary purpose of allowing the Companies to continue to provide safe and reliable service at the lowest reasonable cost in the context of an increasingly dynamic distribution system. They do so by providing more visibility into and control and optimization of the electric distribution system, thereby enhancing system performance and reliability for our customers. That includes improving the Companies' ability to adapt to the operating challenges and potential opportunities created by distributed generation, of which net metering generators are only a part.

Of the Companies' current, planned, or contemplated distribution investments addressed in the cited part of the orders, most are only tangentially related to distributed generation:

- The Companies' Distribution Automation ("DA") program was started during 2017 and is expected to continue through 2022. Associated technologies and line equipment include an advanced distribution management system ("ADMS"), distribution supervisory control and data acquisition ("D-SCADA") system, and electronic reclosers placed on the distribution grid. These technologies enable remote and automatic sectionalization of the grid to

[7] KU Order at 33; LG&E Order at 36.
[8] KU Order at 33-34; LG&E Order at 36.

isolate faults when they occur on the grid due to storms or other disturbances. DA also positively affects distributed generation, including net metering systems, in that it can limit service disruptions that can trip distributed generators offline.

- ADMS provides multiple benefits and serves primarily as the centralized platform for monitoring and operating the electric distribution system. The ADMS utilizes information from D-SCADA and numerous grid assets to optimize network configuration and performance, including outage restoration. Significantly, the ADMS enables manual and automated fault location, isolation, and service restoration ("FLISR"). Associated functionality was deployed early in 2021.
- D-SCADA was deployed early during 2019. The system essentially supervises the distribution system through monitoring, protecting, and controlling various substation and line equipment. It also serves to provide the Companies' ADMS and outage management system ("OMS") with necessary operating data from field devices.
- Advanced Metering Infrastructure ("AMI") is planned to be deployed over the next six years, and has numerous operational and customer-facing benefits, including reduced meter reading and field services costs, increased rate design options (including prepaid service), enhancing usage data available to customers and customer service representatives, and providing vastly enhanced data to the Companies to aid in voltage regulation, system operations, work

planning, and system restoration. It will also give the Companies much better data about distributed generation, including net metering.

- Volt-Var Optimization ("VVO") is being driven by advancing electrification of end use devices and distributed generation. The planned software will be a module of the ADMS and is being enabled by DSCADA and AMI investments. VVO will provide a critical function to minimize distribution system losses by optimizing reactive power flows and voltage loss on the distribution system. AMI will provide critical feedback to the VVO engine and allow the Companies to monitor local power flows and voltages at the point of service delivery to ensure that VVO operation is optimal. VVO implementation will increase distributed generation hosting capacity by better managing system voltage that is often a limiting factor when interconnecting distributed generation.
- Finally, the Companies are investigating and tentatively planning a Distributed Energy Resource Management System ("DERMS"), which will be another module of the ADMS. The DERMS will enable communications with distributed energy resources interconnected to the distribution grid to improve the accuracy of planning and interconnection impact studies, hosting capacity, and masked or hidden load. A DERMS can reduce disruption and safety issues due to renewable generation variability and intermittency, improve load flow calculations with updated weather forecasting, and improve resource planning to support distributed generation growth. Of all the distribution systems addressed in the cited portion of the orders, this is the only one with a primary purpose that is directly related to distributed generation.

These current, planned, or contemplated distribution investments positively benefit distributed generation. Without these investments, the oversight required to optimize the grid for distributed generation would be cumbersome, resulting in potential negative power quality and reliability impacts for our customers.

But perhaps most importantly, net metering—and particularly net exports from net metering customers—would not avoid *any part* of these current, planned, or contemplated distribution investments. Indeed, it is only because of distributed generation that the Companies are considering an investment in DERMS, which is a net *additional* distribution capacity cost, not an *avoided* distribution capacity cost. The benefits of DERMS might justify the cost, but those benefits are not likely to be distribution capacity benefits; rather, they are likely to be energy-related benefits, such as improved power quality and voltage regulation.

Q. The Commission's June 30, 2021 orders further state, "Additionally, the basis for some of these investments, such as voltage regulation, can be accomplished by other means like distributed resources."[9] Would you like to comment on this statement?

A. Yes. Distributed generation alone cannot provide services to the grid such as voltage regulation unless centralized monitoring and control are put in place through systems such as ADMS, DERMS, SCADA, and AMI. As I mentioned above, voltage regulation is an energy-related benefit, not a distribution capacity benefit. And even with those distribution systems in place, net metering customers' net exports alone will

[9] KU Order at 33-34; LG&E Order at 36.

not be enough to permit voltage reductions sufficient to create appreciable energy savings.

Q. The orders cited above further state, "To ignore the impact or benefit of these investments, or alternatives to these investments, in determining the NMS-2 export compensation rate is unreasonable."[10] Would you like to comment on this statement?

A. Yes. The Companies are not ignoring the impact of these investments when determining the export compensation rate for NMS-2; rather, as I discussed above, net metering will likely help the Companies avoid *none* of the Companies' current, planned, or contemplated distribution investments listed in the cited text of the orders. It is the Companies' view that the NMS-2 compensation rates, and particularly the avoided energy cost component discussed in the testimony of Mr. Seelye and David S. Sinclair, will fully compensate new net metering customers for the value their net exports provide, including the value made possible by the Companies' distribution system investments.

Q. Are any of the Companies' actual or potential distribution investments intended or designed to frustrate or supplant the deployment of additional distributed generation?

A. Absolutely not. The Companies' actual or potential distribution investments would increase distributed generation hosting capacity by optimizing the performance of the electric system to allow distributed generators to interconnect while the Companies continue to provide safe and reliable service at the lowest reasonable cost.

[10] KU Order at 34; LG&E Order at 36.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

J.K. Wolfe
John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of July 2021.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, 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**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS 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. 2020-00350**

SUPPLEMENTAL DIRECT TESTIMONY OF
BETH MCFARLAND
VICE PRESIDENT - TRANSMISSION
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: July 13, 2021

TABLE OF CONTENTS

I. INTRODUCTION, BACKGROUND, AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is Beth McFarland. I am Vice President of Transmission for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I hold a master's degree in electrical engineering from the University of Louisville and have held a number of engineering, managerial, and executive positions with the Companies for almost 25 years. A complete statement of my work experience and education is in Appendix A.

Q. Have you previously testified before the Commission?

A. I have sponsored a number of responses to data requests for the Companies, including in their 2018 base rate cases and their 2018 Integrated Resource Plan filing.[1]

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a framework for evaluating avoided transmission capacity cost resulting from net metering. Also, I support the reasonableness of the avoided transmission capacity cost calculations performed by the Companies' witness W. Steven Seelye and explained in his supplemental testimony.

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[1] *See, e.g.*, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, KU Response to CAC Initial Requests (Ky. PSC Nov. 29, 2018); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, LG&E Response to ACM Second Requests (Ky. PSC Jan. 2, 2019); *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348, Companies' Response to Commission Staff's First Requests (Oct. 25, 2019).

II. CALCULATING AVOIDED TRANSMISSION CAPACITY COST

Q. What is an appropriate conceptual framework for determining avoided transmission capacity cost arising from net metering?

A. An appropriate conceptual framework for determining avoided transmission capacity cost arising from net metering must include the following:

1. It must consider future investments, not embedded costs. There is no amount of net metering that can change investments already made. Therefore, an accurate framework will consider only future investments.
2. It must recognize the bulk nature of the transmission system. For example, overhead transmission lines' typical normal ratings vary by 75 MVA or more between transmission voltage levels, and therefore between investment levels.[2]
3. It must recognize that transmission components are sized to serve anticipated peak loads and power flows, which can occur at different seasons and times of day for different systems. Therefore, *when* net metering customers' generation can produce net energy onto the Companies' systems is highly relevant, and particularly whether that net production regularly coincides with the transmission system's peak loads.
4. It must recognize that the location of energy exports that affect transmission system components affects either the cost or benefit of those exports. If an export is

[2] *See* Transmission System Operations TO1, Interconnection Training Program, PJM State & Member Training Dept., at 24, available at: https://www.pjm.com/~/media/training/nerc-certifications/TO1-transmissionops.ashx (accessed July 3, 2021). *See also* American Electric Power Transmission Facts at 4, available at: https://web.ecs.baylor.edu/faculty/grady/_13_EE392J_2_Spring11_AEP_Transmission_Facts.pdf (accessed July 3, 2021).

significant enough to have an appreciable effect on transmission components, it might be beneficial if it relieves transmission congestion, or it could exacerbate existing congestion. Also, as noted above, because transmission system components are sized to handle bulk electricity (typically measured in megawatts), it would take a significant amount of net metering capacity (typically measured in kilowatts) to be aggregated behind a transmission component to have an effect on its sizing. The likelihood of this occurring is currently considered remote; certainly the Companies do not plan or choose where net metering customers will locate, what kinds and sizes of facilities they will choose, or when the conditions will be right for actual energy production to occur.

5. It must consider transmission system reliability. Transmission components must perform reliably across a wide range of operating conditions, including a broad array of environmental conditions and system contingencies—including the contingency that generating sources might not perform as expected. Therefore, the dispatchability, intermittency, and reliability of net metering customers' generators must be taken into account.

6. It must account for the limited and necessarily distributed nature of net metering. KRS 278.466(1) limits each utility's obligation to offer net metering service when the utility's aggregate net metering capacity reaches 1% of the utility's annual peak load. Also, net metering generating facilities are necessarily distributed rather than concentrated due to customer choice and the requirements of the Commission's Net Metering Interconnection Guidelines.[3] For example, the Guidelines state, "For

[3] *See, e.g., Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity up to Thirty Kilowatts*, Case No. 2008-00169, Order Appx. A at 3 (Ky. PSC Jan. 8, 2009).

> interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load."[4] It is my understanding that the Guidelines were drafted to ensure net metering would have no appreciable impact on the distribution system, much less the transmission system. This approach limits (or ideally eliminates) cost incurrence related to net metering, but it also limits (and likely eliminates) savings creation.

Although this framework may not be entirely exhaustive, including these items will help ensure a reasonable and accurate assessment of avoided transmission capacity costs resulting from net metering.

Q. Using this conceptual framework, have the Companies identified any avoided transmission capacity cost that net metering has created to date?

A. No. As the Companies stated in their responses to data requests earlier in these proceedings, although the Companies have accounted for distributed energy resources in their transmission planning, such resources have had no effect on the Companies' ten-year transmission project plan because they are *de minimis* relative to the loads served by the Companies' transmission system.[5] This is not a surprising result: the total capacity of all net metering installations in the Companies' Kentucky service territories is less than 20 MW, which is spread over approximately 200 different delivery points on the Companies' transmission system throughout Kentucky. By way of comparison, the Companies do not require customers to make a new transmission service request before adding new load to an existing distribution substation

[4] *Id*.
[5] *See* KU Response to Joint Intervenors 2-19; LG&E Response to Joint Intervenors 2-20.

transformer unless they will add at least 5 MW of incremental load on a *single transformer* on the 69 kV system or at least 10 MW on a *single transformer* on the 138 kV system.

Moreover, because distributed energy resources are intermittent resources that are required to be distributed rather than concentrated, and because of the magnitude and reliability of the change in load at peak that is required to change a transmission-level investment, the Companies do not believe there would be *any* avoided transmission cost resulting from net metering customers' generation resources even if the combined capacity of such resources totaled 1% of peak load for each of the Companies. Consider that KU's Kentucky-only peak load in calendar year 2020 was 3,500 MW, 1% of which is 35 MW.[6] Likewise, LG&E's peak load in calendar year 2020 was 2,505 MW, 1% of which is 25.1 MW.[7] These are small capacity values—particularly when distributed across each of the Companies' systems—and are unlikely to have any impact on transmission investment.

The evidence in these proceedings supports this conclusion. My colleague John Wolfe sponsored responses to data requests in these proceedings showing that KU net metering customers' aggregate capacity is nearly 0.2% of KU's system peak load, yet it is spread across nearly 40% of KU's substation transformers, and only 1.4% of KU substation transformers have connected net metering capacity of greater than 1% of

[6] KU's Kentucky-only peak load is a calculated value but is considered to be a reliable estimate. KU's 2020 Kentucky-only peak cited in the body of the text occurred in the 2:00 – 3:00 p.m. hour on July 21, 2020; the KU total system load in that hour was 3,571 MW. KU's 2020 total system peak of 3,642 MW occurred in the 7:00 – 8:00 a.m. hour on January 22, 2020 (KU's load was 3,483 MW in that hour). Sunrise did not occur until 7:50 a.m. in Lexington, Kentucky that day, making it unlikely that distributed generation provided any material amount of energy at the time of KU's 2020 system peak. (Sunrise data obtained from https://sunrise-sunset.org/us/lexington-ky/2020/1 (accessed July 7, 2021).)

[7] LG&E's 2020 peak load occurred in the 2:00 – 3:00 p.m. hour on July 21, 2020.

substation transformer capacity.[8] Similarly, LG&E net metering customers' aggregate capacity is more than 0.25% of LG&E's system peak load, yet it is spread across nearly 60% of LG&E's substation transformers, and only 2.8% of LG&E substation transformers have connected net metering capacity of greater than 1% of substation transformer capacity.[9] Such truly distributed generation at these aggregated levels does not reduce future transmission investments.

Q. Notwithstanding that net metering has not yet created any avoided transmission capacity cost for the Companies and their customers, is there a reasonable methodology for calculating potential avoided transmission capacity cost that might arise from net metering?

A. Yes. Mr. Seelye presents in his supplemental testimony an approach to calculating avoided transmission capacity cost resulting from net metering that is consistent with the six-point framework I articulated above. It considers only future transmission investments, not embedded costs. It further accounts for the degree to which net metering customers' generating facilities, which are almost exclusively solar photovoltaic systems, are intermittent and the degree to which they tend to produce net energy during the Companies' respective peaks.

What Mr. Seelye's methodology does not do is account for transmission reliability constraints, the step-wise nature of transmission investments (which are instead modeled as straight-line cost curves), and the locational impacts of net metering and timing of its production relative to loading on the system, either positive or negative. Instead, for the sake of simplicity, Mr. Seelye's model assumes all net

[8] KU Response to PSC 6-9.
[9] LG&E Response to PSC 6-9.

metering exports contribute to avoided transmission capacity costs, regardless of the size or location of the exports. These simplifications are necessary due to time and complexity constraints, and they result in more favorable avoided transmission capacity cost values for net metering customers. These observations notwithstanding, Mr. Seelye's calculation methodology is reasonable.

Q. Applying the Companies' proposed calculation methodology, what is the maximum reasonable avoided transmission capacity cost for which the Companies' net metering customers could be compensated?

A. As Mr. Seelye explains in his testimony, the maximum reasonable avoided transmission capacity cost component of NMS-2 for KU is \$0.00025/kWh and \$0.00010/kWh for LG&E. I say these are the maximum reasonable amounts because it remains my professional opinion that there have been and likely will be no avoided transmission capacity costs resulting from net metering. That aside, I believe Mr. Seelye's methodology and calculations are reasonable, and the values he has calculated for avoided transmission capacity cost can serve as reasonable maximum values under current conditions and projections.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Transmission for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Elizabeth J. McFarland

Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of July 2021.

Judy Schooler

Notary Public

Notary Public, ID No. **603967**

My Commission Expires:

July 11, 2022

APPENDIX A

Beth McFarland
Vice President - Transmission
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3648

Previous Positions

LG&E-KU

Vice President – Customer Services	2017 – 2020
Director, Asset Management, EDO	2013 – 2017
Manager, Substation Construction and Maintenance, EDO	2010 – 2013
Lead Engineer, Louisville Arena Project	2007 – 2010
Various Engineering Positions	1997 – 2007

Ford Motor Company

Automation Engineer - Body	1996 - 1997
Maintenance Supervisor - Paint	1994 - 1996

Professional/Trade Memberships

Edison Electric Institute-Reliability EAC	2020 – present
SERC Reliability Corporation-Member Company Representative	2020 – present
North American Transmission Forum-Member Representative	2020 – present

Education

Executive Education Program, Tuck School of Business, Dartmouth College	2017
Master of Engineering, University of Louisville J. B. Speed Scientific School	1994
Bachelor of Science in Engineering Science, University of Louisville J. B. Speed Scientific School	1992

Civic Activities

University of Louisville, J. B. Speed School of Engineering, Industrial Board of Advisors	2019 – present
Leadership Kentucky Board of Directors	2019 – present
Leadership Kentucky Class Member	2019
ACE Mentoring Board of Directors	2017 – present