COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters 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
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 Rebuttal Testimony of Justin R. Barnes
On Behalf of Kentucky Solar Industries Association, Inc.

August 5, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 25711. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Kentucky Solar Industries Association, Inc. ("KYSEIA").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony in the earlier portion of these proceedings, as well as supplemental testimony on July 13, 2021. I also submitted testimony to the Commission in Case No. 2020-00174 addressing the Kentucky Power Company's ("KPC") most recent general rate case application on aspects of the application addressing the proposed N.M.S. II tariff and rates for small power production facilities.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR REBUTTAL TESTIMONY AND HOW IT IS ORGANIZED.

A. My testimony responds to the Supplemental Testimony filed by Kentucky Utilities Company ("KU") and Louisville Gas and Electric ("LG&E"; collectively, the "Companies") on July 13, 2021. Section II of my testimony responds to the Companies' new proposal on establishing avoided energy and capacity rates applicable to Qualifying Facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), tariffs SQF and LQF. I describe major shortcomings with the Companies' proposal and provide recommendations on better methodologies for fairly valuing the energy and capacity provided by QFs.

Section III of my testimony addresses the Companies' proposals with respect to avoided energy cost, ancillary services cost, generation capacity cost, transmission capacity cost, distribution capacity cost, carbon cost, environmental compliance cost, and job benefits as they relate to calculating the NMS-2 export compensation rates. I explain how the Companies have failed to conduct an analysis consistent with the guidance offered by the Commission's decision on KPC's N.M.S. II tariff, and in doing so systematically underestimated the long-term costs avoided by net metered generation. Where possible I have also developed recommendations for specific rates for different components of the NMS-2 rate.

Section IV provides my concluding remarks and summarized recommendations.

II. SQF AND LQF TARIFFS

Q. DID THE COMPANY PROPOSE REVISED SQF AND LQF RIDERS IN ITS SUPPLEMENTAL TESTIMONY?

A. Yes. Mr. Conroy sponsored the revised tariffs and Mr. Sinclair sponsored the derivation of the rates that the Companies propose to offer under those tariffs.

Q. PLEASE SUMMARIZE THE REVISIONS THAT THE COMPANIES PROPOSE TO MAKE TO RIDER SQF AND RIDER LQF.

A. The Companies propose several changes. Most notably, they propose offering a fixed price 20-year PPA option with a separate option for a QF to enter into a 2-year PPA instead of a 20-year contract. They also propose specific energy and capacity compensation rates denominated in $/kWh that are differentiated into categories for solar tracking, solar fixed tilt, wind, and "other" technologies. These rates are differentiated by the year in which a QF facility begins delivering energy. Both the energy rates and capacity rates are levelized over the 20-year life of the contract. The 2-Year contract does not include capacity compensation.

The capacity rates, where applicable, are differentiated into two tranches comprised of the first 109 MW of contracted QF nameplate capacity and the next 891 MW of contracted QF nameplate capacity with lower rates for the second tranche. Thus capacity compensation would be limited to the first 1,000 MW of contracted QF nameplate capacity, pending review and potential revision as part of a biennial avoided cost filing process.

Q. DO YOU AGREE WITH THE ESTABLISHMENT OF A 20-YEAR PPA OPTION AND 2-YEAR OPTION?

A. Yes. In my direct testimony in this proceeding, I recommended that the Companies be directed to offer a long-term contract option that includes compensation for capacity. Although this aspect of their proposal does not exactly replicate my own recommendations for revised QF tariffs, it is aligned with the character and reasoning behind my recommendation, therefore, I support it. I did not recommend a separate 2-Year contract option in my direct testimony, but I also believe this aspect of the Companies' proposal to be reasonable.

Q. DO YOU DISAGREE WITH ANY ASPECTS OF THE COMPANIES' PROPOSED REVISED RIDERS SQF AND LQF?

A. Yes. My areas of disagreement are as follows:

1. The "lowest rate" selection methodology that the Companies employ to determine rates for different technologies is at odds with common sense and the concept of marginal costs.
2. The avoided cost rates specified in the revised tariffs do not include adders for avoided line losses for either energy or capacity. The tariffs should be modified to differentiate between facilities connected at transmission and distribution voltage where facilities connected at distribution voltage receive a higher rate that accounts for avoided transmission energy and demand losses. According to the Companies line loss studies, the appropriate gross ups for KU are 3.295% for demand losses, applicable to

the capacity rates, and 2.827% for energy, applicable to the energy rates.[1] For LG&E the appropriate gross-ups are 1.549% for demand losses, applicable to the capacity rates, and 1.033% for energy, applicable to the energy rates.[2]

3. The calculation of the capacity rates, which uses different methodologies for different technologies, results in discrimination of solar QFs relative to wind QFs or QFs that employ an "other" technology. The capacity rate calculation should utilize a single technology neutral methodology based on the cost of a proxy natural gas combined cycle unit based on the next hypothetical addition to the Companies' system in its IRP. The use of a proxy market price based on a single utility-scale solar PPA fails to reflect the Companies' long-term avoided costs.

4. The solar capacity factors that are used to translate the cost of "perfect" dispatchable capacity for solar QFs understate the contribution of solar QFs to meeting capacity needs. The calculation uses a simple average of estimated solar capacity factors over 12 separate monthly peak hours. This fails to reflect the fact that system peaks that drive a need for capacity investments are not evenly distributed across all months and monthly peaks of the year. The assumed solar contribution to peak should be calculated using the weighted LOLP methodology I identified in my Supplemental Testimony, which produces a solar ELCC of 58.14% of nameplate capacity

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[1] KU response to PSC 5-20 (filed Apr. 1, 2021) [PDF 151 of 202].
[2] LG&E response to PSC 5-21 (filed Apr. 1, 2021) [PDF 152 of 203].

for a fixed tilt solar array rather than the 28.8% amount calculated by the Companies.

Q. PLEASE ELABORATE ON YOUR OBJECTION TO THE "LOWEST RATE" METHODOLOGY THE COMPANY EMPLOYS TO DETERMINE DIFFERENT RATES APPLICABLE TO DIFFERENT TECHNOLOGIES.

A. There are at least two major logical failures with this aspect of the Companies' proposal. First, consider what such an approach would mean in practice for the purchase of any valuable good or service. In the context of the Rhudes Creek PPA, the Company is saying that it will never pay more to a specific type of vendor (e.g., solar) than what it paid in the past for that commodity, but it would pay more for the exact same commodity that provides equivalent value from a different type of vendor (e.g., wind). This like a general consumer saying that because they were able to purchase gasoline from an Exxon station at a specific price in the past, they will never pay a higher rate to purchase gasoline from any Exxon station. On the other hand, because that consumer has never purchased gasoline from a Valero station, they are willing to pay more than that amount for the exact same product, and they would pay still more from a third vendor. Such an approach to purchasing decisions flies in the face of economically rationale decision-making, and ratepayers will pay the cost of that irrationality.

Second, marginal costs refer to the incremental costs associated with the next purchase of a given product or service. In an economically rational world, the incremental cost is effectively defined on the basis of the maximum price a consumer is willing to pay based on the value a product has to that consumer. For instance, in organized wholesale markets, participants that make successful sale offers of energy and capacity receive the clearing price rather than the price they may have bid into the market. That clearing price is the price offered by the most expensive offer that allows supply to meet demand. In other words, it is maximum price based on the value of the underlying good or service. The costs avoided by a substitute are not driven by the lowest offer, they are driven by the highest price that might need to be paid in the future.

Q. PLEASE EXPLAIN HOW THE CAPACITY RATE DERIVATION IS DISCRIMINATORY TO SOLAR QFS.

A. The Companies employ three methods for calculating avoided costs for different technologies and then select the lowest indicated by each for a given technology. One calculation uses the Rhudes Creek PPA as a baseline all-in compensation rate for both energy and capacity. Another uses an index of solar and wind PPA prices as the all-in price baseline. The third uses a bottom-up calculation of capacity costs for a combustion turbine under the "peaker" methodology that was historically employed by KPC for developing avoided capacity rates. The lowest rate selection method results in the selection of the Rhudes Creek PPA for solar, the PPA index for wind (because there is no equivalent Rhudes Creek PPA for wind), and the CT peaker method for "other" technologies.

This methodology creates a discriminatory pricing regime for QFs in which each of the three technology categories (i.e., Solar, Wind, and Other) gets a different capacity rate that is <u>not based on actual avoided costs</u>. The discriminatory nature of the Companies' proposed methodology is evident from the absurdity of its pricing recommendations compared to the capacity value actually provided by each type of resource. For example:

- Wind and Other technologies receive higher capacity rates than Solar for an identical amount of equivalent capacity.
- Fixed-tilt Solar is compensated at a lower rate than Wind even though the Companies' peaker methodology evaluation demonstrates that Fixed-tilt Solar has a *higher* capacity value per MW-year,[3] and this value is spread over assumed production that is lower for Solar than for Wind.[4]
- Both Single-axis and Fixed-tilt Solar resources have a higher availability during peak hours, both on an annual basis and during the summer peaks specifically, than Wind resources.[5] Yet both types of solar resource would generate less total capacity revenue per MW than a wind resource.
- The on-peak capacity factor premium for Single-axis tracking Solar is 29% over Fixed-tilt Solar, but the rate premium is only 7%.[6]
- The total rate (i.e., energy plus capacity) paid for a Single-axis tracking Solar is *lower* than for Fixed-tilt Solar despite the considerably higher capacity value for Single-axis tracking Solar.[7] In other words, the

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[3] Supplemental Exhibit DSS-2, Table 9, p. 10 of 16 (filed July 13, 2021) [PDF 127 of 161].
[4] Supplemental Exhibit DSS-1, Table 1, p. 1 of 3 (filed July 13, 2021) [PDF 115 of 161].
[5] Supplemental Exhibit DSS-2, Table 8, p. 9 of 16 (filed July 13, 2021) [PDF 126 of 161].
[6] Supplemental Exhibit DSS-2, Tables 9 and 14 (filed July 13, 2021) [PDF 127, and 131 of 161]. Table 9 provides production profile adjusted avoided capacity costs while Table 14 presents recommended capacity rates.
[7] Kentucky Utilities, Tariff SQF [proposed], Supplemental Testimony at PDF p. 21; LG&E, Tariff SQF [proposed], Supplemental Testimony on PDF p. 26.

Companies are *penalizing* the type of utility-scale solar facilities that actually provides *higher value* to the Companies and its customers.

These incoherent results demonstrate that the Companies' proposed avoided cost methodology is facially discriminatory and produces, in my understanding of the terms, unjust and unreasonable rates for QFs. The Companies do not appear to dispute this contention as they acknowledge that their pricing approach "might not result in avoided cost pricing that is technology neutral".[8] By definition, a pricing approach that is not technology neutral is discriminatory.

Q. CAN YOU ILLUSTRATE THE INCONGRUITIES YOU DESCRIBE ABOVE QUANTITATIVELY?

A. Yes. Table 1 below provides comparisons between the annual capacity revenue that a hypothetical resource would receive under the rates proposed by the Companies for each technology type. As is readily visible, wind technologies generate greater capacity revenue per MW than either type of solar technology despite the fact that wind contributes less to meeting peak needs than either (as measured by the estimated on-peak capacity factor).[9] Wind receives roughly 1.6 times more revenue than Single-axis tracking Solar despite the fact that it only produces 77% of the amount of on-peak capacity on a per MW basis than Single-axis tracking Solar. Wind receives roughly 2.65 times more revenue than Fixed-tilt Solar despite the fact that its capacity value is roughly equivalent an in fact slightly lower.

[8] Companies' response to KYSEIA Supplemental Requests – a.k.a. KYSEIA 3rd, Item 4 (filed Aug. 2, 2021) [PDF 11 of 28].

[9] Uses proposed rates for a 20-year PPA for contracts beginning in 2022.

Table 1: Capacity Revenue vs. On-Peak Capacity Contribution

Technology Type	Annual Capacity Factor (%)	Annual Energy per MW (MWh)	Capacity Rate ($/MWh)	Annual Capacity Revenue per MW ($)	On-Peak Capacity Factor, Monthly Average (%)
Single-Axis Tracking Solar	26.0%	2,278	$1.82	$4,145	37.2%
Fixed-Tilt Solar	16.7%	1,463	$1.70	$2,487	28.8%
Wind	25.3%	2,216	$2.98	$6,605	28.7%

Table 2 below further illustrates the incongruity in pricing by illustrating the implied capacity rate if all technologies were assumed to be 100% available to meet capacity needs. This "perfect" capacity rate is arrived at by dividing the proposed rates by the on-peak capacity factor.

Table 2: Perfect Capacity Equivalent Rate By Technology

Technology Type	Capacity Rate ($/MWh)	On-Peak Capacity Factor, Monthly Average (%)	Equivalent Perfect Capacity Rate ($/MWh)
Single-Axis Tracking Solar	$1.82	37.2%	$4.89
Fixed-Tilt Solar	$1.70	28.8%	$5.90
Wind	$2.98	28.7%	$10.38
Other	$8.27	100.0%	$8.27

As Table 2 shows, the compensation for a hypothetical perfect capacity resource differs greatly based on technology despite the fact that each resource type provides equivalent capacity value. This result arises directly from the Companies' use of different methodologies for determining capacity rates for each technology. This approach is discriminatory by any objective measure.

Q. IS THE USE OF A SINGLE PPA AN APPROPRIATE BENCHMARK FOR DETERMINING MARKET PRICING WHEN CALCULATING THE AVOIDED COST RATE?

A. No. One contract does not determine what the "market price" is, nor is it an appropriate substitute. Using this approach would allow a single project that is a "unicorn" and not replicable in the future to be used as the pricing benchmark in a manner that would discourage purchases from facilities that would be slightly more expensive, but would still be more cost-effective an any available alternative, such as the construction of a new natural gas CT.

This is particularly concerning given recent trends in solar and wind PPAs that show costs are *increasing*.[10] For instance, relative to 2019, projects in the future are likely to have higher land costs and interconnection costs.[11] In addition, federal tax credits have already decreased and will decline further. Finally, solar costs are currently increasing due to rising module costs and other supply chain pressures, with wind PPAs also experiencing recent cost increases.[12] In this context, a single PPA is more similar to a short-term marginal cost, as it is reflective of the cost at specific point in time for the unique configurations and variables applicable to the project, rather than a long-term marginal cost that can be applied prospectively. Simply put, a low-cost PPA from 2019 is not indicative of a utility's

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[10] Level10 Energy, "Q2 2021 PPA Price Index," available at https://www.leveltenenergy.com/post/q2-2021.

[11] The availability of the most attractive sites, where projects can be interconnected without a need for costly upgrades, is not infinite, and competition for land in general places upward pressure on lease rates.

[12] *Id*, p. 7.

cost to enter into a similar PPA in 2022 or 2023. These factors strongly caution against the use of a single PPA to determine the avoided cost price when other methods would provide a better benchmark more indicative of the Companies' current avoided cost.

Q. DO YOU HAVE ANY FURTHER OBJECTIONS TO THE COMPANY'S PROPOSED SOLAR QF PRICING BEING BASED ON THE RHUDES CREEK PPA MARKET PRICING METHODOLOGY?

A. Yes. The Rhudes Creek PPA has an all-in 20-year rate of $27.82/MWh. This is the apparent price benchmark for a lowest cost solar resource. Yet the all-in rates that the Company would offer for 20-year PPAs for other solar resources for contracts beginning in 2022 sum to $25.77/MWh for Fixed-tilt Solar and $25.67/MWh for Single-axis Tracking Solar, both of which are lower than the supposed absolute minimum cost solar resource. This is a result of the Companies' mixing and matching concepts of market-based pricing and proxy unit capacity costs and the manner in which future energy and capacity values are discounted in the levelization process.

The end result is that even though the Companies were willing to pay $27.82/MWh for solar production from the Rhudes Creek solar facility, inclusive of its entire energy and capacity attributes and irrespective of the actual value of the costs that Rhudes Creek allows the Companies to avoid, they would pay less for an identical resource in the future. And as I have previously demonstrated, to add insult to injury, they would pay more for a resource that provides equivalent energy and capacity attributes as long as it is not a solar resource.

Q. IS THE LEVELTEN ENERGY PPA PRICE INDEX AN APPROPRIATE BENCHMARK FOR DETERMINING THE COMPANIES' AVOIDED COST RATE?

A. No. While the PPA pricing data reported by LevelTen Energy can provide general insight into pricing trends and key drivers, it is not an appropriate methodology for determining the Companies' specific avoided cost rate in their service territories, for several reasons. First, by nature it is backwards looking in the same manner as the Rhudes Creek PPA is backwards looking.

Second, the LevelTen Energy PPA Price Index Report evaluates the prices that wind and solar project developers have offered for PPAs available on the "LevelTen Energy Marketplace" using the P25 pricing point. The P25 pricing point refers to the most competitive 25th percentile offer price – and *not* the average executed PPA price. Thus the index only reflects the lower end of the offer price range, does not account for actual project execution (i.e., which projects fail?), and by its very nature cannot reflect the numerous variations in PPA terms that could materially influence the way a project is priced. Ultimately, the index is more useful for illustrating pricing trends rather than it is for defining specific price points.

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH USING MARKET PRICING APPROACHES TO SET AVOIDED COST RATES?

A. Yes. The two "market" pricing options proposed by the Companies do not equate to the value to the Companies relative to how the utility might otherwise fulfill its capacity need. As a result, it fails to incentivize on-peak production that actually produces the capacity benefits, as the *averaged* rate used under these options is spread over all production. As previously discussed, these approaches also fail to account for recent trends indicating that market pricing is increasing for solar and wind projects due to a variety of factors. If the Companies used the same approach, it would suggest that it would not be prudent for them to build a new natural gas combustion turbine or combined cycle facility if the levelized cost of electricity from the facility was greater than the market price.

Q. DOES THE COMPANIES' AVOIDED COST METHOD APPROPRIATELY ADDRESS THE CONTRIBUTION OF SOLAR TO MEETING ITS CAPACITY NEEDS?

A. No. By using the two market pricing approaches, the Companies' proposed capacity rates for solar QFs do not actually have any connection to the contribution that either a solar or wind QF would make to meeting its future capacity needs. Under these approaches, the capacity price is simply the residual difference between the respective all-in market prices and the avoided energy cost. The only place where a contribution to peak methodology is used to define capacity value is in the calculations associated with defining avoided capacity costs under the natural gas CT peaker method. The Company does not propose to use this method to define capacity rates for solar or wind QFs.

Q. IS THE SOLAR CAPACITY CONTRIBUTION THAT THE COMPANIES USE IN THEIR PEAKER METHOD CALCULATIONS AN ACCURATE REFLECTION OF SOLAR'S CONTRIBUTION TO MEETING CAPACITY NEEDS?

A. No. The Companies' calculations of solar contribution to meeting peak needs is based on a simple average of 12 monthly values based on modeled solar production at the time of each monthly peak. This is reflected in Figure 1 below, a re-creation of Table 8 in Supplemental Exhibit DSS-2.

Table 3: Company Derived Peak Contributions

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%

The simple averaging method weights the peak during each month equally. However, using a simple average capacity factor during all months with all weighted equally conflicts with how the Companies conduct their planning using LOLP[13] and

[13] Application (filed Nov. 25, 2020), Direct Testimony of Steven S. Seelye ("Seelye Direct"), p. 105 [PDF 109 of 491] lines 9-10, stating "LOLP is a critical measurement the Companies use to plan their generation resources."

does not reflect the value that solar capacity is expected to provide at the most critical times (i.e., when the loss of load probability is highest). The Companies' methodology undervalues solar's contribution to grid reliability and produces, in my view, unjust and unreasonable rates for QFs.

A more accurate and fairer method for compensating solar that aligns with the Companies planning is for the effective solar capacity determination to be based on a representative solar production profile weighted according to hourly LOLP, as I recommended in my Supplemental Testimony. My analysis based on the Companies' LOLP study incorporated into its cost of service study produces a solar ELCC of 58.14% of nameplate capacity for a fixed tilt solar array. Such a result is not dissimilar to the June – August average shown in Figure 1 (66.3% for Solar – Fixed Tilt). The reason for the similarity is that the Companies' high LOLP hours are concentrated in the summer afternoon hours.

I also note here that the Companies actually acknowledge that the effective capacity contribution of solar is related to June – August peaks excluding all other months in their proposal to establish tranches with different levels of capacity compensation within Riders SQF and LQF. As discussed by Witness Sinclair, the tranche applicable to meeting a 2028 capacity need of 100 MW would allow up to 127 MW (nameplate) of Single-axis Tracking Solar to receive the applicable capacity rate based on the effective summer capacity factor of 78.6% for this type of resource (i.e., 100 MW / 78.6% = 127 MW).[14] This is an implicit recognition that 127 MW of Single-axis Tracking Solar provides 100 MW of effective capacity.

Q. WHAT IS A BETTER METHOD FOR DETERMINING AVOIDED CAPACITY COST RATES FOR RIDERS SQF AND LQF?

A. I recommend the proxy unit method for establishing the avoided cost rate methodology, which would use a natural gas combined cycle unit as the next capacity unit in accordance with the Companies' current IRP. Alternatively, the Commission could utilize a combustion turbine as the proxy capacity unit as the Companies did in developing their own avoided cost pricing proposal. Capacity payments should be directly tied to what a QF produces during peak times. This is calculated by dividing the capacity cost (i.e., revenue requirement) for the proxy NGCC unit across the on-peak hours. It would produce a technology-neutral rate, where a single rate is used for all technologies, but QFs would earn different amounts based on their performance during peak periods. It also incentivizes pairing QFs with technologies like battery energy storage systems to better align deliveries with grid needs.

Q. CAN YOU PROVIDE AN ILLUSTRATIVE TIME-DIFFERENTIATED CAPACITY RATE FOR RIDERS SQF AND LQF?

A. Yes. Table 3 presents an on-peak capacity rate for all QF production based on the Companies' assessment of annual avoided costs based on the cost of a natural gas CT. The rates reflected in Table 3 are derived by dividing the annualized avoided

[14] Supplemental Testimony of Sinclair, p. 15 (filed July 13, 2021) [PDF 105 of 161].

capacity cost ($) for 20-year contracts beginning in each year from 2022-2026, with an adjustment to the rate for avoided transmission demand losses specific to each utility. The rates in Table 3 would apply to delivered energy on summer (June – September) weekdays from 11 AM – 8 PM. The rates themselves are arrived at by dividing the annualized cost per MW by the number of hours in this timeframe (791 hours).[15] The rates without transmission losses would apply to QFs interconnected at transmission voltages whereas the utility specific rates would apply to QFs interconnected at distribution voltage.

Table 3: Proposed Tranche 1 On-Peak Capacity Rates

	2022	2023	2024	2025	2026
Levelized CT Cost ($/MW)	$72,488	$81,175	$90,514	$100,553	$111,339
Rate ($/MWh), w/o Transmission Losses	$91.67	$102.66	$114.47	$127.17	$140.81
Rate LG&E ($/MWh), w/Losses	$93.65	$104.87	$116.94	$129.90	$143.84
Rate KU ($/MWh), w/Losses	$95.23	$106.65	$118.92	$132.11	$146.28

Q. HOW DID YOU SELECT THE ON-PEAK HOURS FOR THIS RATE?

A. I reviewed the LOLP patterns from the study the Companies conducted for their cost of service study. In this review, I discovered that 98.68% of the total annual LOLP occurs during the June – September period and that 98.38% of this amount occurs on weekdays. I selected the 11 AM – 8 PM timeframe based on the percentage of total summer LOLP accounted for by each of the 24 hours during a day by excluding each daily hour that accounts for less than 1% of total annual

[15] The 791 hours is derived as 9 hours per day (9*122), multiplied by (5/7) to exclude weekends.

LOLP. The resulting hours within the on-peak period account for 97.12% of total annual LOLP, which means that they cover the vast majority of hours during which there is an apparent need for capacity.

Q. PLEASE EXPLAIN WHY TRANSMISSION LOSSES NEED TO BE INCORPORATED INTO THE RATES PAID TO DISTRIBUTION CONNECTED QFS.

A. A distribution-connected QF that does not backfeed to the transmission system does not incur transmission losses. Therefore the energy and capacity produced by a distribution-connected QF is worth incrementally more than a resource connected to the transmission system. The specific transmission loss factors reflected in the rates in Table 3 are 3.88% for KU and 2.15% for LG&E. Those rates include both transmission losses and primary substation losses to reflect the avoidance of losses on both the bulk transmission system and losses that would be incurred by backfeed through a primary substation onto the transmission system.

Q. DID YOU MAKE ANY LOSS ADJUSTMENTS TO REFLECT FIXED CORE LOSSES AS OPPOSED TO VARIABLE LOSSES?

A. No. Such an adjustment is not justified because distribution-connected QFs would not incur core transformation losses at the substation and the figures I used reflect averaged losses. Averaged losses fail to reflect the higher losses that occur during peak load periods which coincide with the on-peak period I used for the on-peak rate. Thus any fixed losses that might exist and could merit a reduction in the loss factor calculation are offset by the fact that the averaged losses understate variable losses during the high load periods that comprise the on-peak pricing window. Thus on the balance the loss figures I used should be considered reasonable.

Q. IF THE COMMISSION WERE TO USE A MARKET PRICING APPROACH TO DETERMINE AVOIDED CAPACITY COSTS, ARE ANY MODIFICATIONS NECESSARY TO THE COMPANY'S METHODOLOGY?

A. While a market pricing based rate would be a sub-optimal design for the reasons I have previously discussed, if the Commission were to elect this approach I recommend that:

- The Rhudes Creek approach be rejected and market prices be determined based on LevelTen pricing indices.
- The LevelTen prices used to calculate an average market rate should be confined to only the two most recent quarters available (Q4 2020 and Q1 2021) given older data is not reflective of current market conditions. This would produce an all-in price of $35.45/MWh for solar facilities.
- Use this all-in price ($35.45/MWh) as the combined price for energy and capacity without discounting the capacity component according to the year of the Companies' future capacity needs because the market price itself is an all-in energy price and does not reflect the true marginal cost of new capacity.
- The Commission should consider utilizing an adder to the average prices to reflect the fact that the LevelTen indices use only the P25 price offers (i.e., top 25% least-cost) rather than an average, median price, or P50 price.

Alternatively, it would also make sense to further explore whether access to more complete pricing could be arranged.

Again, I emphasize that such a market pricing approach produces a poor reflection of future marginal capacity costs, fails to reward facilities with delivery profiles that align with peak system needs, and will always produce differing and discriminatory rates for different technologies. Furthermore, it relies on hard-wired assumptions of facility characteristics that make it impossible to adapt to facilities that have different characteristics than the broad categories it uses (e.g., battery-paired systems, varied inverter sizing ratios, dual-axis tracking solar, etc.).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANIES' PROPOSED RIDERS SQF AND LQF.

A. The Commission should:

- Accept the Companies' proposal to offer a 20-year fixed rate option under both QF riders.
- Deny the Companies' proposed capacity pricing design and instead adopt the summer on-peak capacity rate design I recommend in the body of my testimony.
- Adopt both energy and capacity prices for distribution-connected QFs that reflect the avoidance of energy and demand losses on the transmission system that distribution-connected QFs avoid.

Secondarily, if the Commission declines to adopt my summer on-peak capacity rate proposal and instead elects to rely on a market price based approach, it should modify the Companies' proposed design in the following ways:

- Use LevelTen pricing as opposed to the Rhudes Creek PPA as the appropriate market price benchmark.
- Only use LevelTen pricing from only two most recent quarters to determine the all-in price, resulting in an all-in rate of $35.45/MWh for solar resources.
- Apply the all-in price of $34.45/MWh as a true all-in rate without separate calculation of a capacity rate.
- Consider the use of an adder or other adjustment to reflect the fact that the LevelTen price indices reflect only the lowest cost offers on the platform rather than average, median, or 50th percentile offers.

Finally, if the Commission elects to use the peaker method based on a combustion turbine to determine capacity rates but does not adopt my summer on-peak rate pricing proposal, the on-peak capacity factor for fixed tilt solar used in the calculation should be modified to 58.14% based on my solar LOLP analysis. The peak capacity contribution for single-axis tracking solar should also be revised using the same methodology but I have not independently performed such a calculation.

III. NMS-2 EXPORT COMPENSATION RATES

Q. DO YOU HAVE ANY HIGH-LEVEL CONCERNS WITH THE COMPANIES' TARIFF NMS-2 AS PROPOSED IN THEIR SUPPLEMENTAL TESTIMONY?

A. Yes. The Companies continue to propose a shift away from monthly netting to a new policy in which all exported generation from a net metering customer would be credited at the dollar-denominated bill credit rate of $0.02319/kWh. I discuss in more detail below why this bill credit rate understates the value of excess generation provided by net metering customers. But as an initial point, I note that this price equates to a 29.6% decrease relative to the average solar PPA price the Company calculated as the blended "average" (actually, the P25) PPA price in MISO and PJM and a 16.6% decrease relative to its Rhudes Creek PPA.[16] In other words, the Companies are proposing a NMS-2 compensation rate that is not only dramatically less than the current retail rate for customers, but is significantly less than its own solar PPA and the PPAs entered into across the region with renewable resources.

For reasons further articulated in the Direct Testimony of Benjamin Inskeep in this proceeding, I strongly oppose this proposal by the Companies. Because this approach is confusing for customers, unnecessarily complicated, and would make estimating the financial viability of a distributed generation ("DG") facility extremely difficult, among other reasons, I recommend that the Commission adopt

[16] Calculated as follows: ($0.03296 - $0.02319)/($0.03296) = 29.64% and ($0.02782 - $0.02319)/($0.02782) = 16.64%. *See* Supplemental Exhibit DSS-2, pp. 3 and 5 of 16 (filed July 13, 2021) [PDF 120, 122 of 161], for average LevelTen Energy PPA Price Index and Rhudes Creek PPA pricing, respectively.

the monthly netting regime that it adopted for Kentucky Power Company and that is currently in place for the Companies under their net metering tariff. I recommend the dollar-denominated bill credit established in this proceeding be applied to the customer's net excess generation that accrues over the monthly billing period.

A. Avoided Energy Costs

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE AVOIDED ENERGY COSTS?

A. The Companies proposed setting the Avoided Energy Cost component at \$0.02319/kWh for NMS-2 customers, which is the same rate it developed for qualifying facilities under LQF and SQF for Fixed-tilt Solar based on the average avoided energy cost they calculated for 2022 and 2023.[17]

Q. IS THE COMPANIES' AVOIDED ENERGY COSTS CALCULATION REASONABLE?

A. No. As an initial matter, the Avoided Energy Cost should not be set below the energy rate established for QFs electing the 20-year rate option proposed by the Companies for tariffs SQF and LQF for fixed-tilt solar facilities. For fixed-tilt solar facilities installed in 2022, the 20-year rate proposed by the Companies for fixed-tilt solar facilities is \$24.07/MWh, or \$0.02407/kWh.[18] Net metering customers that install solar facilities are making a long-term investment in a generating facility that has an expected life of at least 25 years. There is no reason to believe these customers would decommission these facilities earlier than necessary, given a net

[17] Supplemental Testimony of Seelye, p. 9 (filed July 13, 2021) [PDF 51 of 161].

[18] Supplemental Exhibit RMC-1 (filed July 13, 2021) [PDF 18 of 161].

metering customer's financial payback of such an investment is contingent on them remaining in service and generating electricity.

Furthermore, the Avoided Energy Costs calculated by the Companies were not grossed up for line losses. Excess generation from net metering facilities interconnected to the distribution system does not incur any transmission losses, unlike centralized power plants, or even transmission-interconnected QFs. They also do not use a substantial portion of the distribution system, as excess generation flows in the path of least resistance – typically, to nearby neighbors.

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING AVOIDED ENERGY COSTS?

A. A more transparent and logical approach would be to use the LG&E PJM interface three-year daytime-only (with escalation and discounting over time) methodology used for KPC, as I recommend in my Supplemental Direct Testimony. This pricing approach represents the value of substitute energy from either a purchase or sale standpoint and would align the Companies' valuation of Avoided Energy Costs with the established method for KPC.

Q. COULD A DIFFERENT INDEX OTHER THAN THE LG&E PJM INTERFACE PRICE BE USED FOR THIS PURPOSE?

A. I recommended the use of the LG&E PJM interface because it constitutes a readily accessible market for substitute energy and offers transparency in pricing. If substitute energy was more commonly purchased or excess sold through different means, another price basis could be used. However, in practice a prudent utility would presumably purchase substitute energy from the least-cost source but sell excess energy at highest price available. A full examination of off-system sales and purchases could identify an average rate, but could be complicated to perform and less transparent than simply using a single publicly available market index. For that reason, my view is that using a single public source is preferrable.

Q. IS IT POSSIBLE FOR THE AVOIDED ENERGY COMPONENT OF THE NMS-2 RATE TO DIFFER FROM THE AVOIDED ENERGY RATE APPLIED UNDER RIDERS SQF AND LQF?

A. Yes, because net metering facilities and typical grid-supply QFs are delivering energy with different characteristics. A net metering system is exporting energy after it services on-site load in an un-forecasted manner. This means that the temporal profile of exports will differ from the production profile of the net metering facility, and because the deliveries are un-forecasted, they would not be incorporated into the operational decisions governing Company-owned generation units. Accordingly, the avoided energy costs correspond to the as available market price represented by the LG&E-PJM interface price, or another available index.

On the other hand, the Company would presumably incorporate the expected energy deliveries from grid-supply QFs into the operational decisions for Company-owned generation. Under these circumstances, the avoided energy costs are tied to the marginal energy costs of Company-owned units because forecasted QF generation substitutes for energy that would otherwise be generated by Company-owned generation units rather than substituting for “imbalance” energy.

Q. IF THE COMMISSION WERE TO BASE AVOIDED ENERGY COSTS ON THE COMPANY'S METHODOLOGY FOR DEFINING 20-YEAR FIXED RATES FOR QFS, ARE ANY MODIFICATIONS NECESSARY TO APPLY THESE RATES TO NMS-2 FACILITIES?

A. Yes. Two modifications are necessary. First, the Company used a 6.75% discount rate in performing the levelized cost operation, whereas in the KPC proceeding the Commission adopted a methodology that uses a risk-free discount rate of 1.4%. Making this modification increases the avoided energy rate from $0.02407/kWh for fixed tilt solar facilities to $0.02432. Second, a loss adder needs to be applied to reflected avoided transmission and distribution losses. The respective loss adders for LG&E and KU are 5.33% and 7.65%, respectively. The combined adjustments produces an energy rate of $0.02562/kWh for LG&E and $0.02618/kWh for KU.

B. Avoided Generation Capacity Costs

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE AVOIDED GENERATION CAPACITY COSTS?

A. The Companies argue that net metering customers should receive *no* credit for avoided generation capacity costs.[19] In the alternative, they argue that net metering customers should not receive a credit for avoided generation capacity costs that "exceed the cost that the Companies would incur from purchasing power from a solar purchased power agreement."[20] The Companies calculate this upper bound

[19] Supplemental Testimony of Seelye, pp. 22-23 (filed July 13, 2021) [PDF 64 of 161].
[20] Supplemental Testimony of Seelye, p. 23 (filed July 13, 2021) [PDF 64, 65 of 161].

value at \$0.00170/kWh in 2022 and \$0.00191/kWh in 2023 based on the Rhudes Creek PPA.[21]

The Companies used three methods for calculating avoided costs for different technologies and then picked the lowest value of the three methods for a given technology. The three methods were: (1) the Rhudes Creek PPA as a baseline all-in compensation rate; (2) an index of solar and wind PPA prices as the all-in price baseline; and (3) a bottom-up calculation of capacity costs for a combustion turbine under the "peaker" methodology. The Companies choice to use the lowest value resulted in the selection of the Rhudes Creek PPA for solar.

Q. ARE THE COMPANIES' RECOMMENDATION ON AVOIDED CAPACITY COST COMPENSATION FOR NET METERING CUSTOMERS REASONABLE?

A. No. As I have previously discussed, the Companies' continued refusal to acknowledge the avoided capacity cost benefits of excess generation provided by net metering facilities directly contradicts the Commission's findings in the KPC Order,[22] as well as how the capacity benefits of variable renewable energy generation is evaluated and compensated in nearly every wholesale market in the United States. Net metering customers' excess generation provides a quantifiable capacity value, and net metering customers should be compensated accordingly.

The Companies' contention that it is impossible for non-contracted resources to contribute to avoiding new generation capacity investments is factually

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[21] Supplemental Exhibit DSS-1, Table 14 (filed July 13, 2021) [PDF 131 of 161].
[22] Case No. 2020-00174 (Ky PSC May 14, 2021) Order, p. 31.

incorrect and defies logic. Net metering customers have a direct, substantial incentive to keep their system operating to recoup their significant upfront investment. There is no legitimate danger of system attrition, and the Companies have not substantiated their claims along these lines with any evidence. In fact, according to information provided by the Companies, only two out of a total of 1,189 net metering customers (0.11%) have ceased operation. [23] Excess generation aggregated across net metering customers can be measured, forecasted, planned for, and used to the benefit of the Companies' customers to avoid duplicative capacity investments or purchases.

The Companies' claims about net metering customers being unable to provide avoided capacity value are undercut by their own treatment of distributed generation, electric vehicle deployment, and demand-side management ("DSM") measures in their integrated resource planning. The Companies' IRP forecasts the deployment of these measures when determining their peak demand and energy needs.[24] This means that they ascribe capacity value in their IRP to DSM measures, even when DSM customers have no contract and no specific obligation. In response to an information request the Companies concede that this is true.[25] While this particular response goes to great length to try to distinguish DSM from net metering systems, *nowhere* does it contest the premise that DSM counted towards the

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[23] Companies' Response to MA-KFTC-KSES Supplemental Requests – a.k.a. MA-KFTC-KSES 3rd, Item 8 (filed Aug. 2, 2021) [PDF 31 of 620] at Attachment for Item 8.
[24] 2018 IRP, available at https://psc.ky.gov/pscecf/2018-00348/rick.lovekamp%40lge-ku.com/10192018102925/3-LGE_KU_2018_IRP-Volume_I.pdf
[25] Companies Response to KYSEIA Supplemental Requests, Item 11(d) (filed Aug. 2, 2021) [PDF 20 of 28].

Companies' capacity position in its IRP is not subject a contractual obligation or other long-term commitment.

Q. ARE THE COMPANIES' AVOIDED CAPACITY COSTS CALCULATION METHODOLOGY REASONABLE FOR NET METERING CUSTOMERS?

A. No. The Companies argue that if an avoided capacity cost is assigned to net metering customers, then the value for 2022 and 2023 should be based on pricing from a single solar PPA executed in 2019. The value is computed as the difference between the Rhudes Creek energy cost ($27.82/MWh) and the avoided cost of energy it separately calculated based on forecasted hourly energy costs developed in PROSYM. As I discussed in the context of capacity pricing for QFs, this approach has multiple failings, not the least of which is that it is discriminatory on the basis of technology type. However, putting aside that dubious premise, an even more concerning aspect of the Companies' methodology is that it relies exclusively on a single PPA contract. A single PPA price point is not a reliable or transparent cost basis for determining the Avoided Capacity Cost, and it is not reflective of the Companies' long-term avoided capacity costs.

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING AVOIDED CAPACITY COSTS?

A. As I discussed in my Supplemental Testimony and previously in my Supplemental Rebuttal Testimony, the Avoided Capacity Cost calculation should utilize a single technology neutral methodology based on the cost of a proxy natural gas combined cycle unit based on the next hypothetical addition to the Companies' system in its IRP. Furthermore, since system peaks that drive a need for capacity investments are not evenly distributed across all months and monthly peaks of the year, the assumed solar contribution to peak should be calculated using the weighted LOLP methodology that reflects the capacity benefits a typical solar net metering facility is forecasted to provide relative to the risk of a capacity shortfall at a given hour in the year.

In my Supplemental Testimony I calculated an initial avoided capacity cost based on the PJM Net CONE for an NGCC unit as a proxy capacity addition. In this calculation I used a placeholder for demand losses of 5%. Updating this with Company-specific demand losses results in avoided capacity cost rates of \$0.0362/kWh and \$0.0371/kWh for LG&E and KU, respectively.

Q. THE COMPANY'S PEAKER UNIT METHODOLOGY USES A COMBUSTION TURBINE AS THE PROXY CAPACITY UNIT. HOW WOULD THIS CHANGE THE AVOIDED CAPACITY COST YOU HAVE CALCULATED?

A. Using the same methodology as I employed for my NGCC-based estimate and updated loss factors, the respective rates for a combustion turbine based on PJM Net CONE rates would be \$0.0391/kWh and \$0.0401/kWh for LG&E and KU, respectively.

Q. PLEASE EXPLAIN WHY THIS AMOUNT DIFFERS FROM THE RATES THE COMPANIES CALCULATE USING A COMBUSTION TURBINE AS A PROXY CAPACITY RESOURCE.

A. There are several reasons with varying levels of significance on the results. The most prominent differences are: (a) the Companies use an effective solar capacity contribution of 28.8% for fixed tilt solar, whereas my LOLP-based solar capacity contribution produces a 58.14% on-peak capacity factor, (b) the amount I derived does not reflect the timing of the next capacity need using a discounted levelization process, and (c) the Companies did not apply loss factors in their calculations. There are other differences in the manner in which the Companies perform the capacity cost calculation that differ from how the PJM does so, but the core cost assumptions are not dramatically different.

Q. WHAT WOULD THE AVOIDED CAPACITY RATE FOR FIXED TILT SOLAR BE USING THE COMPANIES' COMBUSTION TURBINE METHODOLOGY WITH ADJUSTMENTS TO THE SOLAR EFFECTIVE CAPACITY AND INCLUSION OF LOSS FACTORS?

A. Table 4 below shows the implied avoided capacity rates ($/MWh) for fixed tilt solar based on the Companies' combustion turbine methodology for 20-year periods starting in 2022 through 2026 with the effective solar capacity factor adjustment and added demand loss factors. I also adjusted the annual solar capacity factor that is used to estimate the annual solar production used in the denominator of the rate derivation from the 16.7% used by the Companies to 15.17%. The 15.17% capacity factor is based on the annual capacity factor in nameplate (DC) watts for the solar production profile I used in calculations.

Table 4: NMS-2 Capacity Rates Based on Gas CT Peaker Methodology

Utility	2022	2023	2024	2025	2026	Average	2022-2024 Average
LG&E	$0.03372	$0.03776	$0.04211	$0.04678	$0.05179	$0.04243	$0.03786
KU	$0.03457	$0.03872	$0.04317	$0.04796	$0.05310	$0.04351	$0.03882

As is readily visible in Table 4 the implied rates for systems installed during the next several years is similar to my preliminary estimate based on an NGCC unit and PJM Net CONE, lower in 2022, roughly the same though slightly higher in 2023, and significantly higher in 2024 and beyond. By contrast, the Companies' proposed NMS-2 capacity rate of $0.00170/kWh in 2022 and $0.00191/kWh in 2023 based on the inappropriate Rhudes Creek market price methodology is dramatically lower. While I continue to recommend that the rates I developed based on the PJM Net CONE for an NGCC are reasonable for use within the NMS-2 rate calculation, the values in Table 4 based on the Companies' capacity cost calculation for a natural gas CT could be used instead. The resulting rates would be nearly identical if a forward-looking two or three year average is used.

Q. YOU RECOMMENDED AN ON-PEAK RATE FOR AVOIDED CAPACITY COSTS FOR RIDERS SQF AND LQF. DO YOU ALSO RECOMMEND THAT A TIME-DIFFERENTIATED CAPACITY RATE BE EMPLOYED FOR NMS-2 AVOIDED COSTS?

A. No. Implementing a time-differentiated rate for NMS-2 avoided capacity would require that all NMS-2 customers be equipped with meters capable of such measurement. That would constitute an added, unnecessary cost at the present time. Furthermore, it would create a disconnect between the non-time-differentiated rates at which net metering customers purchase energy from the Company and the rates at which net excess production is compensated. Such a disconnect could be confusing to customers, make bill savings projections more uncertain, and introduce mixed incentives with respect to how NMS-2 customers behave with respect to their energy use patterns.

C. Avoided Transmission Costs

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE AVOIDED TRANSMISSION COSTS?

A. The Companies argue that net metering customers should receive *no* compensation for avoided transmission costs.[26] In the alternative, they argue that Avoided Transmission Costs are, "at most," $0.00025/kWh for KU and $0.00010/kWh for LG&E.[27] These values were derived by taking the projected total transmission plant additions for retail load growth over 2021-2030, calculating an annual revenue requirement, and dividing that by annual kWh sales.

Q. ARE THE COMPANIES' RECOMMENDATION ON AVOIDED TRANSMISSION COST COMPENSATION FOR NET METERING CUSTOMERS REASONABLE?

A. No. The Companies' argument is effectively a self-fulfilling prophecy: If a critical mass of distributed generation must be installed to cause transmission cost avoidance and only then be eligible to receive compensation for the value of that transmission cost avoidance, then the critical mass will never be reached in the first place because the price signals are not in place to incentivize incremental DG deployment.

[26] Supplemental Testimony of Seelye, p. 25 (filed July 13, 2021) [PDF 67 of 161].
[27] Supplemental Testimony of Seelye, p. 26 (filed July 13, 2021) [PDF 68 of 161].

In reality, each incremental unit of capacity or reduced load has a definable value based on the unitized avoided marginal costs. Failing to compensate DG customers for small incremental load reductions will undervalue the benefits of excess generation and result in the self-fulfilling prophecy described above. Each incremental kW of load reduction provided by DG offsets an equivalent kW of load increase on the system that contributes to the incurrence of additional transmission investments. Similarly, load increases (e.g., a residential customer adding an air conditioning unit) are typically incremental and generally small in nature *individually*, but cumulatively they result in incremental transmission costs. The same principle is true for incremental reductions provided by DG facilities.

Q. DOES AVOIDING TRANSMISSION LOADING PRODUCE BENEFITS TO THE COMPANIES' CUSTOMERS BEYOND AVOIDANCE OF FUTURE INVESTMENTS?

A. Yes. The Companies' transmission system is the source of a considerable amount of revenue which acts as an offset to the embedded costs that its customers would otherwise pay. The amounts of these offsets have increased considerably over the last several years. For instance, in KU's service territory, the transmission revenue offset for residential customers was roughly \$3.75 million in the Company's 2016 rate case.[28] In the 2020 rate case, the offset increased to \$11.74 million.[29] Such outside revenue is made possible by the availability of transmission capacity

[28] Case No. 2016-00370. Company response to PSC 3-27, Attachment entitled "2016 KU 3rd Data Response Attachment to PSC Q27 - KU COSS - BIP with Unit Cost Sheets"
[29] Case No. 2020-00349. Company response to AG-KIUC 1-188, Attachment entitled "2020 AG-KIUC KU DR 1 Attach to 188 - att 1".

beyond what is necessary to serve the Companies' native loads. That available capacity can be enhanced by the transmission load reductions provided by net metering customers.

Q. ARE THE COMPANIES' METHODLOGY FOR CALCULATING AVOIDED TRANSMISSION COSTS FOR NET METERING CUSTOMERS REASONABLE?

A. No. The calculations provided by the Companies do not actually yield the marginal value of avoided transmission costs nor do they reflect the value that existing available transmission capacity has as revenue generator. With respect to marginal costs, the Companies did not identify the kW load carrying capability of the investments in the Companies' business plan. Instead, the Companies simply divided the calculated forecasted annual incremental transmission revenue requirement in 2022-2031 by annual kWh sales.[30] This calculation fails to establish a relationship between how costs vary on a *capacity unitized basis*, which is necessary for computing the transmission cost avoidance.

A serious shortcoming of this methodology is that it fails to consider that the need for transmission is driven by peak needs. If unitized kWh costs are used, they should be confined to the peak hours that actually cause transmission costs to be incurred. Instead, by dividing costs across all kWh of consumption to produce a rate fails to account for how DG exports contribute to peak reductions. In addition, the Companies' methodology fails to gross up solar contributions to avoided

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[30] Supplemental Testimony of Seelye, p. 26 (filed July 13, 2021) [PDF 68 of 161].

transmission capacity for demand losses. A kW of solar at the point of load avoids transmission capacity at a premium based on losses (i.e., transmission capacity must have a rating of 1 kW, *plus losses*, to serve 1 kW of load).

The same rationale applies when evaluating how available existing transmission capacity can generate value and how that value can be enhanced by transmission load reductions provided by net metering generators. The availability of excess transmission capability would be correlated with the amount necessary to serve the Companies' native loads and would likely be most valuable during peak periods when the need to transmit electricity to where it is needed is at its highest.

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING AVOIDED TRANSMISSION COSTS?

A. Ideally, Avoided Transmission Costs are determined for DG facilities by (1) calculating the marginal cost per kW of incremental transmission capacity, (2) determining how the solar production shape aligns with the peaks that define cost causation for transmission investment, and (3) calculating the portion of the unit cost that a given kW of PV nameplate can avoid.

Avoided Transmission Costs can be estimated in this case using unit transmission costs, i.e., the cost per kW of the system as a whole as it exists currently as a representation of the average marginal cost per unit of system utilization (kW). While a more robust estimation methodology would be based on the results of a marginal cost study, the Companies do not seem to perform this type of analysis, necessitating the use of my method as a reasonable proxy, as this type of study is not something other parties would be able to perform independently.

The unit costs of the existing system can be used to determine what a given increment of transmission capacity has historically cost. While it's backwards-looking, it still provides insight into the value of avoiding the expense associated with adding a kW of transmission capacity. I note that the Commission's KPC Order estimated Avoided Transmission Capacity Costs using historical data, finding the value to be $0.01245/kWh, or several orders of magnitude larger than the maximum values estimated by the Companies in this case.[31]

I also note that the embedded unit cost approach aligns with the use of existing transmission assets to generate revenue, as the unit costs directly represent a cost-based rate for those existing assets.

Q. WHAT SPECIFIC AMOUNTS FOR AVOIDED TRANSMISSION COSTS DOES YOUR UNIT COST ANALYSIS METHOD PRODUCE?

A. In my Supplemental Testimony I provided preliminary rates of $0.01037/kWh for LGE and $0.01989/kWh for KU under an LOLP-based unit cost methodology, and $0.00812/kWh for KU and $0.00782/kWh for LG&E, under a 6CP methodology.[32] I have updated these amounts to: (a) correct an error in the net cost of service amount used to calculate transmission unit costs for LG&E under a 6CP methodology,[33] and (b) update the demand loss factor adder to replace a general

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[31] Case No. 2020-00174 (Ky PSC May 14, 2021) Order, p. 32.

[32] Unit costs used for this calculation are derived from residential net cost of service amounts divided by class load (kW). The use of net cost of service in this calculation implicitly incorporates historic depreciation and offsetting revenues, which likely actually cause it to understate the true marginal costs of new transmission investments.

[33] The previous calculation inadvertently used gross cost of service to calculate unit costs for LG&E, rather than net cost of service. The calculation for KU is not affected by this revision.

5% placeholder with Company-specific amounts.[34] The resulting updated figures are shown in Table 5.

Table 5: NMS-2 Avoided Transmission Capacity Rates

Utility	LOLP Methodology ($/kWh)	6CP Methodology ($/kWh)
LG&E	$0.01050	$0.00637
KU	$0.02065	$0.00843

The amounts presented in Table 5 are current, or Year Zero, amounts that have not been escalated under the escalation, discounting, and levelization methodology employed in calculating net metering rates for KPC.

Q. DO YOU RECOMMEND THAT A SIMILAR ESCALATION AND DISCOUNTING CALCULATION BE MADE TO DEVELOP LEVELIZED AVOIDED TRANSMISSION RATES IN THE CURRENT PROCEEDING.

A. Not necessarily. I agree in principle with the methodology employed for KPC, but after further review of available data it is my view that devising an appropriate escalation rate is somewhat challenging. Based on the cost of service information submitted by the Companies in this rate case and their prior two rate cases, the annualized escalation of net cost transmission rate base over the four years that have elapsed since the end of the test year in the Companies 2016 rate case (June 30, 2018) and the end of the test year for the current rate case (June 30, 2022) is 9.43% for LG&E and 16.08% for KU. These escalators are based on demonstrated, real increases in transmission investment and costs and as such provide a solid measure

[34] 6.325% for LG&E and 9.017% for KU based on full demand losses for transmission and distribution.

of cost escalation over recent years. However, assuming cost escalation in these amounts could produce rather extraordinary levelized long-term avoided cost estimates that some might consider questionable.

In light of that fact, an alternative approach could be to use the escalation in net cost of service for the same time period.[35] The annualized escalation based on this metric is 4.19% for KU and 2.01% for LG&E. Table 6 presents the levelized long-term avoided transmission costs using these escalation rates and the 1.4% risk-free discount rate employed for KPC under both the LOLP and 6CP solar contribution to peak scenarios.

Table 6: Levelized NMS-2 Avoided Transmission Rates

Utility	LOLP Methodology ($/kWh)	6CP Methodology ($/kWh)
LG&E	$0.01327	$0.00806
KU	$0.03426	$0.01399

To be clear, I suggest this as potential measure of future escalation that could be used by the Commission on the basis that net cost of service reflects both the cost side of existing transmission and the ability of that existing transmission to generate revenue. However, given the uncertainties involved and the impact that the escalation rate selection has on the rate calculation, my recommendation is that the Year Zero rates I have calculated be used in the current proceeding. This would effectively assume that cost escalation takes place at the same rate as the risk-free

[35] Escalations are based on residential unit costs for ease of calculation. A system-wide analysis could be conducted by summing the applicable amounts for each class of customer.

discount rate. Refinement of methods used to estimate cost escalation could be pursued in future proceedings.

<u>D. Avoided Distribution Costs</u>

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE AVOIDED DISTRIBUTION COSTS?

A. The Companies argue that net metering customers should receive *no* compensation for avoided distribution costs.[36] In the alternative, they argue that Avoided Distribution Costs are, "at most," $0.00046/kWh for KU and $0.00012/kWh for LG&E.[37] These values were derived by taking the projected total distribution plant additions for retail load growth over 2021-2030, calculating an annual revenue requirement, and dividing that by annual kWh sales.

Q. ARE THE COMPANIES' RECOMMENDATION ON AVOIDED DISTRIBUTION COST COMPENSATION FOR NET METERING CUSTOMERS REASONABLE?

A. No. Similar to its Avoided Transmission Cost arguments, the Companies' argument here is a self-fulfilling prophecy: If a critical mass of distributed generation must be installed to cause distribution cost avoidance and only then be eligible to receive compensation for the value of distribution cost avoidance, the critical mass will never be reached in the first place because the price signals are not in place to incentivize incremental DG deployment.

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[36] Supplemental Testimony of Seelye, p. 27 (filed July 13, 2021) [PDF 69 of 161] *see also* Supplemental Testimony of John W. Wolfe, p. 7 (filed July 13, 2021) [PDF 143 of 161].
[37] Supplemental Testimony of Seelye, p. 28 (filed July 13, 2021) [PDF 70 of 161].

Each incremental unit of capacity or reduced load has a definable value based on the unitized avoided marginal costs. Failing to compensate DG customers for small incremental load reductions will undervalue the benefits of excess generation and result in the self-fulfilling prophecy described above. Each incremental kW of load reduction provided by DG offsets an equivalent kW of load increase on the system that contributes to the incurrence of additional distribution investments.

Q. IS THE COMPANIES' METHODLOGY FOR CALCULATING AVOIDED DISTRIBUTION COSTS FOR NET METERING CUSTOMERS REASONABLE?

A. No. The calculations provided by the Companies do not actually yield the marginal value of avoided distribution costs for similar reasons described above for Avoided Transmission Costs. The Companies simply divided the calculated forecasted annual incremental distribution revenue requirement in 2022-2031 by annual kWh sales.[38] This calculation fails to establish a relationship between how costs vary on a *capacity unitized basis*, which is necessary for computing the distribution cost avoidance.

The Companies' use of a 10-year forward-looking period for calculating both transmission and distribution avoided costs is also inappropriate and could understate the benefits of DG facilities, particularly if avoided costs in future years (years 11-25) are higher than the average avoided costs in the first ten years. One

[38] Supplemental Testimony of Seelye, pp. 27-28 (filed July 13, 2021) [PDF 69, 70 of 161].

of the principles the Commission adopted in its KPC Order was the use of "forward-looking, long-term, and incremental analysis," and "[g]iven that the typical warranty provided by a solar panel manufacturer is 25 years, this would be an appropriate analysis period for Kentucky Power's net metered customers."[39]

The Companies' methodology fails to consider that the need for distribution is driven by peak needs, in this case demands on the distribution system driven maximum class demands. If unitized kWh costs are used, they must be adjusted to reflect the contribution that solar provides during those peak hours that actually cause distribution costs to be incurred. Instead, by dividing costs across all kWh of consumption to produce a rate fails to account for how DG exports contribute to peak reductions.

As the Companies note, DG facilities are dispersed throughout their system.[40] By providing generation at the point of load and excess generation to nearby neighbors, DG facilities help to reduce load on distribution system substations during peak periods, which allows load increases that might otherwise trigger a need for upgrades to existing distribution system facilities. These real, incremental distribution system benefits should be compensated accordingly.

[39] Case No. 2020-00174 (Ky PSC May 14, 2021) Order, p. 23.
[40] Supplemental Testimony of Wolfe p. 4, lines 9-21 (filed July 13, 2021) [PDF 140 of 161].

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING AVOIDED DISTRIBUTION COSTS?

A. As I discussed in my Supplemental Testimony, I recommend a unit-cost based approach that relies on: (a) defining the incremental cost of a given unit of distribution capacity ($/kW), (b) identifying the alignment of typical solar production to distribution peaks, in the form of an effective solar capacity contribution during typical peak hours (%), and (c) calculating a rate based on estimated annual energy production from that same hypothetical solar unit. This functionally the same as the unit cost method that I employed to calculated avoided transmission costs. As with transmission, the rate should be grossed up based on a distribution demand loss factor.

Q. HAVE YOU QUANTIFIED THE DISTRIBUTION AVOIDED COST?

A. Yes. Using the top 10% of residential class load hours to define a solar capacity contribution and the distribution unit cost approach I described in my Supplemental Testimony, the effective solar capacity factor is 9.09% for KU and 14.43% for LG&E. After applying this factor to distribution demand-related unit costs, dividing by annual solar production and adding a demand loss adder produces an initial Year Zero distribution avoided cost of $0.00251/kWh for LG&E and $0.00147/kWh for KU.

Q. PLEASE EXPLAIN WHY THE TOP 10% OF CLASS LOAD HOURS IS A REASONABLE BASIS ON WHICH TO CALCULATE EFFECTIVE SOLAR CAPACITY IN RELATION TO DISTRIBUTION COSTS.

A. Cost-based rate regulation generally values consistency over time with respect to the allocation of costs in a cost of service study. For that reason, methods that could result in dramatic differences in cost allocation from test year to test year are disfavored. For instance, a single coincident peak ("1CP") method could produce large differences in implied cost responsibility if the timing of the 1CP could vary considerably from test year to test year. Relying on a single peak hour in any context introduces the potential for this type of volatility.

The same rationale can be applied in the context of this case when determining the effective solar capacity contribution to reducing distribution loads. During a given test year, maximum class demand might occur during late afternoon during the summer, early evening during the summer, early morning during the winter, or mid-morning during the winter. Those maximum demands can be similar in magnitude (i.e., placing a similar strain the grid) even though their timing differs and the timing can have a significant impact on the implied solar contribution to reducing distribution load. For instance, the solar contribution for the hour ending at 4 PM is much different than it would be at the hour ending at 6 PM. Using an average of solar production during high load hours rather than a single hour mitigates the potential for large swings in solar value attribution that may be transitory artifacts of a specific test year.[41]

Furthermore, while maximum class demand during a single hour is frequently used as a measure of cost causation for the distribution system, the fact is that it is relatively imprecise because individual distribution circuits peak at different times depending on the character of the loads they serve. For instance, few if any distribution circuits exclusively serve residential customers and by and large non-residential classes tend to peak later in the morning or earlier in the evening than the residential class. While it may not be possible to more precisely define cost responsibility on a circuit by circuit basis, using an average of high class load hours helps introduce diversity reflective of the diversity of load on the distribution system. To be clear, where class loads consistently occur during low or zero solar production hours, my approach still reflects this characteristic.

Q. HAVE YOU IDENTIFIED AN ALTERNATIVE APPROACH TO THE EMBEDDED UNIT COST APPROACH FOR ESTIMATING THE MARGINAL COST OF DISTRIBUTION CAPACITY?

A. Yes. In response to an information request the Companies provided information on the incremental load carrying capability of planned distribution investments in their portfolio. I used these amounts along with the annualized carrying costs that Mr. Seelye used in his calculations to calculate implied marginal distribution capacity

[41] For instance, for LG&E using the single highest load hour would produce an effective solar capacity of roughly 15.1% while the average of the top two hours is 26.6%.

costs in unitized ($/kW) figures.[42] Applying the same effective solar contribution and loss factors to these unit costs produces similar, slightly higher, avoided distribution cost rates. Table 7 presents the results of both sets of distribution unit cost calculations.

Table 7: NMS-2 Avoided Distribution Capacity Rates

Utility	Embedded Unit Cost Methodology ($/kWh)	Implied Marginal Unit Cost Methodology ($/kWh)
LG&E	$0.00251	$0.00297
KU	$0.00147	$0.00306

Both sets of rates in Table 7 refer to initial, Year Zero amounts without the use of the escalation, discounting, and levelization procedure employed in the KPC proceeding.

Q. DO YOU RECOMMEND THAT A SIMILAR ESCALATION AND DISCOUNTING CALCULATION BE MADE TO DEVELOP LEVELIZED AVOIDED DISTRIBUTION RATES IN THE CURRENT PROCEEDING.

A. No. As with the transmission cost component I have reservations about recommending a specific escalation rate for distribution costs. Therefore my recommendation is to use the Year Zero values, which is akin to assuming a moderate escalation in costs at the same rate as the risk-free discount rate (1.4%). For the sake of transparency, the distribution escalation rates I calculate based on net cost rate base are 8.6% for LG&E and 8.8% for KU. The alternative amounts

[42] Companies' response to KYSEIA Supplemental 1-13. The unit costs are derived by dividing annualized carrying costs ($) by the incremental load carrying capability of those investments (kW).

based on residential net cost of service are negative (0.86%) for LG&E and 0.43% for KU.

It is difficult to reconcile the demonstrated significant increases in distribution costs as reflected in net rate base with the modest or declining escalation rates based on net residential cost of service. Clearly, there must be other factors involved in creating this disconnect, but I have not been able to conduct a comprehensive analysis to identify those factors and the adjustments they may require to calculating escalation rates. For that reason, as with the transmission cost component, I suggest that refinements be pursued in future proceedings.

Q. DO YOU RECOMMEND THAT THE COMMISSION USE THE EMBEDDED UNIT COST APPROACH OR IMPLIED MARGINAL COST APPROACH FOR CALCULATING AVOIDED DISTRIBUTION RATES?

A. I recommend the rates derived based on the embedded cost approach for two reasons. First, doing so would create consistency with the method I recommended for the transmission cost component. Second, the implied marginal costs are based on Company data that I believe merits further review that was not possible to conduct in a comprehensive manner in the current proceeding. On this second point, there are two significant questions that require investigation. First, are the Companies' business plans actually a good long-term predictor of future distribution investments, particularly in years well into the future? Second, are any changes needed to the Companies' method of categorizing costs as load-related vs. non-load-related necessary. Both factors could have a material impact on the ultimate results of the calculation. I recommend that these issues be explored further in future proceedings.

E. Avoided Carbon Costs

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE AVOIDED CARBON COSTS?

A. The Companies argue that net metering customers should receive *no* compensation for Avoided Carbon Costs because "**currently** there are no laws or regulations that put a price on CO2 emissions,"[43] (emphasis added).

Q. ARE THE COMPANIES' RECOMMENDATION ON AVOIDED CARBON COST COMPENSATION FOR NET METERING CUSTOMERS REASONABLE?

A. No. The Companies exclusively focus on the (lack of a) current carbon pricing regime to avoid any consideration of how a typical DG facility will provide tangible avoided carbon cost benefits for at least 25 years into the future. Yet again, the Companies fail to abide by the principle adopted by the Commission in the KPC Order to "[c]onduct **forward-looking, long-term**, and incremental analysis," when compensating net metering customers (emphasis added).[44]

Resource planning should consider reasonably expected long-term costs associated with a given resource. Fossil resources, whether the continued operation or new resources, can reasonably be expected to have long-term carbon costs if they

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[43] Supplemental Testimony of Seelye, p. 28 (filed July 13, 2021) [PDF 70 of 161]; s*ee also* Supplemental Testimony of Sinclair, p. 20 (filed July 13, 2021) [PDF 110 of 161].
[44] Case No. 2020-00174 (Ky PSC May 14, 2021) Order, p. 23.

are built or continue to operate. Avoided Carbon Costs should therefore be included as a benefit of DG.

The Companies' parent company, PPL Corporation, has determined that climate change could negatively impact its costs and its operations, including its ability to provide safe and reliable service to its customers:

> PPL's businesses could be subject to a variety of risks associated with the potential effects of climate change. Among those risks, climate change may produce stronger and more frequent severe weather, disrupting operations and increasing the costs to prepare for, and respond to, weather events.[45]

In addition to the acute risk climate change poses to the Companies' ability to serve its customers, the Companies face a real risk that new state or federal policies could impose a price on carbon emissions. However, PPL's Climate Assessment "analysis does not explicitly use carbon price as an input to the modeling," but notes that "the implied cost of CO2 emissions may be greater than zero in the [Clean Power Plan] scenario" considered in its analysis.[46] Likewise, its most recent IRP used a very low projected future CO2 cost based upon a low carbon price scenario from a 2016 analysis.[47] While the Clean Power Plan is no longer a regulatory framework under consideration, the Biden Administration has made strong commitments to addressing climate change, including through proposed and anticipated federal legislation and regulation of the power sector. Furthermore, PPL

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[45] PPL Corporation, "PPL Corporation Climate Assessment Assessing the Long-term Impact of Climate Policies on PPL," November 2017, p. 1, available at https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf.
[46] *Id.*, at p. 12
[47] The Companies refer to this as the high CO2 Price scenario, but the values used are actually a low CO2 pricing scenario from the report they cite as the source.

itself has proactively set a goal of "[r]educing carbon emissions at least 80% from 2010 levels by 2050, with at least a 70% reduction by 2040."[48] The Companies strain credulity when claiming the carbon-free nature of excess generation provided by net metering facilities provides no value now and for decades to come.

Therefore, Avoided Carbon Costs include both the costs avoided from any carbon pricing or similar policy framework that could be imposed in the future, as well as reductions to the Companies' operating costs with respect to providing safe and reliable service to its customers as a result of reduced carbon emissions that the Companies admit pose a business risk.

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING AVOIDED CARBON COSTS?

A. The approach employed by the Commission in developing avoided carbon costs estimates is reasonable and should also be employed for calculating the Companies' avoided carbon emission costs. I suggest that a single value be used for both Companies for the sake of simplicity and because they operate their generation portfolio in an integrated fashion.

While this is my recommendation for a "durable" methodology, I am not aware of any readily accessible information on forecasted emission rates, which are used to perform the calculation. The Companies' 2018 IRP contains a forecast of the base system energy mix and fuel burn by fuel type in Table 8-17. This might be used to develop a forecasted emissions profile, though it does not appear to reflect

[48] *Id.*

updated assumptions on potential coal plant retirements or more generally the PPL's objectives of achieving a 70% reduction in carbon emissions from 1990 levels by 2040 and 80% reduction my 2050.[49]

In any case, a lack of information should not prevent the Commission from ascribing any avoided carbon emission value. For that reason, I recommend that the Commission utilize the same rate adopted for KPC ($0.00578/kWh) as an approximation of the Companies carbon costs in the current proceeding. In the alternative, it could be reasonable to attempt to construct an estimate by trending emissions downward to meet a 2040 emissions reduction target and using projected coal retirement dates as inflection points in the trending process. By way of illustration, this would assume that emissions correspond to the 2018 IRP base forecast through 2028, and are then reduced according to the contribution that a given plant retirement makes towards reducing emissions. Such an approach would still require assumptions to be made about replacement resources (e.g., gas vs. zero-carbon).

Q. WOULD USING THE AMOUNT DERIVED FOR KPC BE LIKELY TO OVERSTATE THE COMPANIES' FUTURE CARBON COSTS?

A. No. The Companies' current energy mix is not dramatically different than KPC's and the Companies actually use somewhat higher carbon prices in the sensitivity analysis they conducted as part of their 2018 IRP. For instance, they specify a

[49] This information in itself is inadequate for make a precise calculation because the 2010 emissions benchmark is not specified and the timing of a transition away from carbon-based energy would materially affect the calculation.

carbon price of $17.00/ton in 2026, escalating to $26.00/ton in 2033[50], whereas the calculation employed for KPC assumed a zero carbon price through 2028 and a carbon price of only $17.82/ton in 2033. Furthermore, the base energy forecast from the 2018 IRP actually retains coal and gas generation at roughly their present levels rather than reducing them over time. It seems more likely that using the rate established for KPC would understate rather than overstate the Companies' future carbon costs.

<u>F. Avoided Environmental Costs</u>

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE AVOIDED ENVIRONMENTAL COSTS?

A. The Companies argue that net metering customers should receive *no* compensation for Avoided Environmental Costs because "avoided environmental compliance costs are fully accounted for in the avoided energy and capacity cost components," (emphasis added).[51] Specifically, the Companies state that "variable environmental compliance costs, i.e., those that vary with energy production, are already accounted for in the avoided energy cost calculations,"[52] including "emission control reagents (e.g., limestone, ammonia), emission allowance costs, and an opportunity cost for lost CCR revenues."[53] In contrast, "certain environmental compliance costs are reflected in capital improvements at a unit (e.g., installation

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[50] Companies' 2018 IRP, Table 5-6.
[51] Supplemental Testimony of Seelye, p. 28 (filed July 13, 2021) [PDF 70 of 161]; *see also* Supplemental Testimony of Sinclair, pp. 20, 21 (filed July 13, 2021) [PDF 110, 111 of 161].
[52] Supplemental Testimony of Sinclair, p. 20 (filed July 13, 2021) [PDF 110 of 161].
[53] Supplemental Exhibit DSS-1, Page 1 of 3 (filed July 13, 2021) [PDF 115 of 161].

of a new FGD or baghouse) which would be totally unaffected by energy put on the grid by a customer-generator."[54] The Companies also claim that the Avoided Capacity Cost calculation reflects environmental costs associated with regulations that result in the retirement of generating units.

Q. ARE THE COMPANIES' RECOMMENDATION ON AVOIDED ENVIRONMENTAL COST COMPENSATION FOR NET METERING CUSTOMERS REASONABLE?

A. No. First, the Companies have not transparently identified what their environmental compliance costs are as requested by the Commission. These costs should be clearly identified rather than lumped into the avoided energy and compliance cost calculations so that the costs associated with each are clear.

Second, the Companies do not actually reflect a complete and long-run view of environmental costs that could impact retirement of its generating units:

> Given the large uncertainty and wide range of possible new laws and regulations associated with [new environmental laws and/or regulations that would require retirement and replacement of fossil fuel generation], I am recommending that it be ignored in developing a forecast of future capacity needs."[55]

If the past 50 years of U.S. environmental regulation, as well as current industry trends, are any indication, it is reasonable to assume that additional environmental regulations impacting fossil generating facilities are extremely likely in the decades to come. These impacts cannot simply be ignored; they must be considered when

[54] Supplemental Testimony of Sinclair, p. 21 (filed July 13, 2021) [PDF 111 of 161].
[55] Supplemental Testimony of Sinclair, p. 11 (filed July 13, 2021) [PDF 101 of 161].

evaluating the Avoided Environmental Costs of net metering facilities operating 25 or more years into the future.

Furthermore, *all* relevant environmental compliance costs on a long-term, forward-looking basis should be included in the Avoided Environmental Cost calculation, not just short-run variable costs. This includes forecasted capital investments at a unit to address or mitigate environmental issues in compliance with applicable regulations. Coal combustion residual ("CCR") costs are one example, where the Companies have adjusted their Avoided Energy Cost to account for "opportunity cost for lost CCR revenues," but do not appear to account for the potentially substantial costs of CCR environmental compliance.[56] If the prospect of such lost revenues is incorporated into the avoided energy rate, the cost of CCR mitigation must also be reflected as an environmental cost. Otherwise, the symmetry of benefits offsetting costs is lost.

Furthermore, just as exports from one DG facility may not remove the need for a specific transmission or distribution capacity investment, DG facilities can, in the aggregate, reduce the need for fossil plants and their associated investments related to environmental control technologies over the long-run. They also help reduce the risk to the Company and its customers of future environmental compliance costs that could be imposed through future state or federal regulations or legislation. Net metering customers should therefore be compensated for this benefit.

[56] Supplemental Exhibit DSS-1, Page 1 of 3 (filed July 13, 2021) [115 of 161].

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING AVOIDED ENVIRONMENTAL COMPLIANCE COSTS?

A. It would be reasonable for the Commission to apply a levelized $/kWh amount based on a forward projection of *all* of the environmental compliance costs for the Companies. I have not been able to perform such a calculation, but as with avoided carbon costs, a lack of the necessary data to perform this calculation does not erase the existence of avoided costs.

G. Jobs & Economic Benefits

Q. WHAT DID THE COMPANIES PROPOSE WITH RESPECT TO SETTING THE JOBS AND ECONOMIC BENEFIT FOR NET METERING CUSTOMERS?

A. The Companies argue that net metering customers should receive *no* compensation for a Jobs Benefit because it "would be impermissible because job creation is not within the Commission's jurisdiction."[57]

Q. ARE THE COMPANIES' RECOMMENDATION ON JOBS BENEFIT COMPENSATION FOR NET METERING CUSTOMERS REASONABLE?

A. No. The KPC Order correctly pointed out "that an economic development rate, which many utilities have implemented over the decades, 'is intended to stimulate the creation of new jobs and capital investment.'"[58] The Companies also point out that EDR tariffs "require documentation of job creation and capital investment related to customers who take service under such rates." The Companies try to

[57] Supplemental Testimony of Robert Conroy, p. 6 (filed July 13, 2021) [PDF 8 of 161].
[58] Case No. 2020-00174 (Ky PSC May 14, 2021) Order, p. 38, footnote 122.

make a semantics argument here that since EDR tariffs do not *require* job creation or capital investment, merely its *documentation,* it precludes the Commission from considering job creation and economic benefits in this case.[59]

This argument is absurd. What purpose does information documenting job created and capital investment by EDR tariff customers serve other than to provide the Commission with important information on the costs and benefits of the tariff? That is the same objective that is being contemplated in the current proceeding, especially when one considers my recommendation that Job Benefits receive qualitative consideration in the Commission's ultimate decision. The use case could not be more similar.

Q. WHAT IS A MORE REASONABLE APPROACH TO CALCULATING A JOBS AND ECONOMIC BENFIT COMPENSATION COMPONENT?

A. The Commission should require the Companies to fully and transparently evaluate job and economic development benefits as an export rate component for their next rate case filings. The evaluation should be forward-looking and calculate benefits on a per kWh basis.

In the instant case, given that the utilities have failed to conduct such a *quantitative* analysis, I recommend that the Commission should, at a minimum, consider jobs and economic development benefits as a *qualitative* factor. This can be achieved in two complementary ways. First, the Commission should default to higher-end quantitative estimates of other categories of benefits. Second, the

[59] Supplemental Testimony of Conroy, p. 8 (filed July 13, 2021) [PDF 10 of 161].

Commission should maintain monthly netting under tariff NMS-2. These two approaches would help counteract the under-valuing of excess generation of a net metering customer that would result from providing *no* compensation for this category of benefits as more analysis is conducted.

H. NMS-2 Rate Summary

Q. PLEASE IDENTIFY YOUR RECOMMENDATIONS FOR AVOIDED COST COMPONENTS APPLICABLE MONTHLY NET EXPORTS FROM NMS-2 FACILITIES.

A. Table 8 identifies rates for each component with accompanying notes on how the amounts were derived. Note that the Avoided Energy component rates are italicized to denote them as illustrative requiring some further calculations and adjustment for circumstances where I was unable to finalize a calculation based on my recommended methodology.

Table 8: Summary of NMS-2 Avoided Cost Rates

Avoided Cost Component	LG&E ($/kWh)	KU ($/kWh)	Notes
Energy	*$0.0256*	*$0.0262*	Minimum amount, based Companies' QF rate proposal with discount factor adjustment and loss adders.
Generation Capacity	$0.0362	$0.0371	Calculated rate, based on PJM Net CONE for NGCC and modeled fixed tilt solar resource.
Transmission Capacity	$0.0105	$0.0207	Calculated rate, without long-term levelization.
Distribution Capacity	$0.0025	$0.0015	Calculated rate, without long-term levelization.
Ancillary Services	$0.0006	$0.0006	Proxy based on KPC rate
Carbon	$0.0058	$0.0058	Proxy based on KPC rate
Total Quantified	$0.0812	$0.0918	Sum of quantified rates, pending finalization of rates included for illustrative purposes.
Other Environmental	Non-Zero	Non-Zero	Requires additional information but should be a positive benefit

Jobs Benefits	Qualitative	Qualitative	Qualitative consideration in overall NMS-2 rate development.

Q. PLEASE EXPLAIN WHY YOU HAVE CHARACTERIZED THE AVOIDED ENERGY RATES IN TABLE 8 AS ILLUSTRATIVE.

A. I recommended that the avoided energy rates use a market price index based on the PJM-LG&E interface pricing with escalation and discounting over time via a levelization process. I have not been able to perform that calculation so Table 8 uses a similar methodology based on information made available in the Companies' fixed QF energy rate proposal. The difference between the two is that the Companies' proposed rates are based on operation of their system rather than a market price. I have included those rates, with some adjustments, in Table 8 in order to be able to provide a somewhat illustrative total NMS-2 rate.

IV. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON REVISIONS TO THE SQF AND LQF RIDERS.

A. First, I recommend that the Commission approve the Companies' proposal to make available 20-year fixed price rates and optional two-year rates available to both SQF and LQF participants. Second, I recommend that the Commission reject the Companies' capacity pricing proposal and instead adopt the technologically neutral and value-based summer on-peak capacity rate that I recommend. This would produce the rates below for electricity delivered from 11 AM – 8 PM on weekdays from June – September for 20-year PPAs beginning in each of the years reflected in the table. The rates below reflect Tranche 1 of the Companies proposed capacity pricing regime. The same methodology should also be employed for Tranche 2 of capacity pricing.

Table 9: Recommended On-Peak Capacity Rates for Riders SQF & LQF

	2022	2023	2024	2025	2026
Transmission Connected Rate ($/MWh)	$91.67	$102.66	$114.47	$127.17	$140.81
Distribution Connected Rate- LG&E ($/MWh)	$93.65	$104.87	$116.94	$129.90	$143.84
Distribution Connected Rate - KU ($/MWh)	$95.23	$106.65	$118.92	$132.11	$146.28

Secondarily, if the Commission does not adopt my summer on-peak rate pricing proposal and elects to use the peaker method based on a combustion turbine to determine capacity rates, the on-peak capacity factor for fixed tilt solar used in the calculation should be modified to 58.14% based on my solar LOLP analysis. The peak capacity contribution for single-axis tracking solar should also be revised using the same LOLP-based methodology.

Finally, while I emphasize that this a sub-optimal approach to capacity pricing, should the Commission elect to adopt a market-price methodology for determining avoided capacity rates for QFs, if it chooses to do so it should modify the Companies' proposed pricing regime as follows:

- Use LevelTen pricing as opposed to the Rhudes Creek PPA as the appropriate market price benchmark.
- Only use LevelTen pricing from only two most recent quarters to determine the all-in price, resulting in an all-in rate of $35.45/MWh for solar resources.

- Apply the all-in price of \$34.45/MWh as a true all-in rate without separate calculation of a capacity rate.
- Consider the use of an adder or other adjustment to reflect the fact that the LevelTen price indices reflect only the lowest cost offers on the platform rather than average, median, or 50th percentile offers.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE ESTABLISHMENT OF A RATE APPLIED TO NET MONTHLY EXPORTS UNDER THE NMS-2 TARIFF?

A. First, the Commission reject the rates proposed by the Companies and instead adopt the rates shown in Table 10 below, pending the adjustment of the illustrative avoided energy rate to conform to my recommended methodology.

Avoided Cost Component	**LG&E (\$/kWh)**	**KU (\$/kWh)**
Energy	*\$0.0256*	*\$0.0262*
Generation Capacity	\$0.0362	\$0.0371
Transmission Capacity	\$0.0105	\$0.0207
Distribution Capacity	\$0.0025	\$0.0015
Ancillary Services	\$0.0006	\$0.0006
Carbon	\$0.0058	\$0.0058
Total Quantified	\$0.0812	\$0.0918

In addition, in finalizing the initial NMS-2 tariff and updating it in future proceedings, the Commission should:

- Apply a non-zero amount of avoided non-carbon environmental costs;
- Consider job benefits in a qualitative fashion when determining reasonable rates and the appropriate structural components of the tariff.
- Direct the Companies to conduct a quantitative evaluation of jobs benefits for use in future updates.

- Pursue an effort, through any means that it deems appropriate, to develop a well-defined and replicable methodology for determining reasonable cost escalation rates and long-term marginal costs for use in calculating levelized long-term avoided transmission and distribution rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters 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

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

AFFIDAVIT OF JUSTIN BARNES
VERIFICATION

JURISDICTION)
)
County of Wise, Virginia)

The undersigned, Justin Barnes, being first duly sworn, states the following: The prepared Supplemental Rebuttal Testimony attached thereto constitute the testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements are true and correct. Further, Affiant saith not.

Name of Witness

5th (MH)

SUBSCRIBED AND SWORN to before me on this ~~2nd~~ day of August, 2021 by Joshn Barnes

NOTARY PUBLIC

My Commission Expires: 06/30/2023

MARY LEE HAGY
NOTARY PUBLIC
REG. #7627853
MY COMMISSION EXPIRES 06/30/2023
COMMONWEALTH OF VIRGINIA