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 AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	))))	CASE NO. 2025-00113

AND

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	))))))	CASE NO. 2025-00114

KENTUCKY SOLAR INDUSTRIES ASSOCIATION, INC.
INTERVENOR TESTIMONY
(PUBLIC VERSION)

Comes now the Kentucky Solar Industries Association, Inc. ("KYSEIA"), by and through counsel, and, in accordance with the Public Service Commission's Orders dated June 18, 2025, respectfully tenders its Intervenor Testimony (Public Version) of Jason W. Hoyle into the records of each of the above-styled cases.

WHEREFORE, KYSEIA respectfully submits its Intervenor Testiomony.

Respectfully submitted,

/s/ David E. Spenard

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NOTICE AND CERTIFICATION FOR FILING

Undersigned counsel provides notices that the electronic (public) version of the paper has been submitted to the Commission by uploading it using the Commission's E-Filing System on this 29th day of August 2025. Pursuant to the Commission's July 22, 2021 Order in Case No. 2020-00085 (Electronic Emergency Docket Related to the Novel Coronavirus COVID-19), the paper, in paper medium, is not required to be filed. The non-public version has been transmitted to the Executive Director by electronic mail.

/s/ David E. Spenard

NOTICE CONCERNING SERVICE

The Commission has not yet excused any party from electronic filing procedures for this case.

/s/ David E. Spenard

INTERVENOR TESTIMONY OF

JASON W. HOYLE

ON BEHALF OF

KENTUCKY SOLAR ENERGY INDUSTRIES ASSOCIATION

DOCKET NOS. 2025-00113 and 2025-00114

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Jason W. Hoyle. My business address is 1155 Kildaire Farm Rd., Suite 203, Cary, North Carolina, 27511. My current position is Director of Research at EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

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

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

A. No.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I earned a Bachelor of Science in Mass Communications with a concentration in print journalism from Appalachian State University in Boone, NC in 2001 and a Master of Business Administration from Appalachian State University in 2003. I was employed at the Appalachian Energy Center and the Center for Economic Research and Policy Analysis in various positions of increasing responsibility for nearly 18 years. I was the lead analyst responsible for due diligence, regulatory compliance analysis, pro forma financial and valuation analysis, including PPA negotiations and innovative carbon financing opportunities for nearly a dozen community-based renewable energy projects on behalf of local governments across North Carolina. My work also included research, analysis, and implementation activities related to a variety of energy policy and related programs such as the N.C. State Energy Plan, the North Carolina Climate Action Plan Advisory Group, U.S. Environmental Protection Agency programs, Climate Action Reserve protocols, as well as a variety of other consulting work performed on behalf of state universities, municipal and county governments, and non-profit corporations. I also served as a faculty member in the Appalachian State University's Department of Sustainable Technology and the Built Environment between 2012 and 2021, where I developed and taught graduate and undergraduate courses focused on the policy, market, and economic context of utility regulation and energy project development.

I joined EQ Research in early 2022 as a Principal Energy Policy Analyst and am currently the Director of Research at EQ Research. In my current position, I lead EQ's General Rate Case service which includes preparing and reviewing analyses of rate case filings for electric utilities across the country. I also coordinate EQ Research's regulatory and compliance consulting services for Community Choice Aggregation programs in California, including regulatory monitoring and analysis, compliance reporting, litigation support, and resource procurement planning, including integrated resource planning and other resource procurement plans. My CV is attached as Exhibit JWH-1.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS IT RELATES TO THIS PROCEEDING.

A. My experience at Appalachian State included a wide variety of work related to developing renewable energy and distributed generation projects, conducting financial analysis, and considerable experience evaluating utility rates and programs, including those of municipal electric utilities, rural electric cooperatives, and investor-owned utilities, as well as state-level renewable energy/distributed generation policy. Additionally, I designed and conducted multiple surveys and data-intensive studies on energy-related topics in support of state and national policymakers and for publication in peer-reviewed journals during my time with the Appalachian Energy Center and the Center for Economic Research and Policy Analysis. In my present role, among other duties, I review and analyze rate case filings of investor-owned utilities throughout the country, including cost-of-service studies and distributed generation programs and proposals. Additionally, I have submitted testimony before utility commissions in North Carolina, Michigan, and Virginia on topics that include return on equity, net metering, and generation meter requirements, as well as testimony before the New York Department of Environmental Conservation on bulk power system reliability.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to evaluate the Companies' proposed changes to Rider NMS-2 and Tariffs SQF and LQF and to make recommendations on modifications and other changes to the proposals.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony first addresses the energy and capacity components of avoided cost rates in Section II, and later in the same section addresses terms and conditions of Tariffs SQF and LQF. Section III of my testimony addresses the additional components of the export credit for Rider NMS-2, including distribution capacity, transmission capacity, ancillary services, carbon costs, other proposed changes to the terms of the Rider, and the

Companies' method for determining when they have met the 1% net metering cap. Section IV briefly addresses co-located batteries' market growth, capacity contributions, and potential to benefit all ratepayers through increased disaster resilience. Finally, Section V provides some final thoughts on the Companies' proposals and a summary of my recommendations.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the following:

- The energy credit be increased to include variable minor maintenance costs based on PJM's most recent default minor maintenance cost values using the method in the example I provided;
- The Companies should clarify the circumstances under which they propose a solar or wind QF or Rider NMS-2 customer-generator with a co-located or coupled battery energy storage system would be compensated based on the "Other" QF technology type and that the proposed QF tariffs and Rider NMS-2 rates be adjusted accordingly;
- The BESS-based capacity credit methodology for determining the $/MWh price paid to QFs should be corrected so that the capacity credit value would be sufficient to allow the Companies to recover the full costs of the resource if the Companies were compensated in the same manner as QFs or Rider NMS-2 customers;
- The pricing structure for capacity compensation be adjusted to reflect seasonality and timing of peak loads and provide a price signal sufficient to influence market participants' contribution to peak demand;

- All QFs and Rider NMS-2 customers receive a capacity credit because the Companies have demonstrated an immediate and ongoing capacity need which could be fully or partially met by all types of QFs – including solar during winter if paired with a battery;
- The denial of capacity compensation for BTM QFs be rejected;
- Excluding BTM QFs from eligibility to enter into a PPA be rejected;
- Required all QFs, including BTM QFs, to enter into a PPA with and agreement term length defined separately from the price term length and an agreement term length of sufficient duration to enable QFs to obtain financing and certainty regarding the conditions under which they sell power to the Companies;
- The proposed expansion of liability protections for the Companies be rejected;
- Apply the PV Watts default DC-to-AC size ratio of 1.2 to the DC power rating of net metered PV systems for purposes of calculating the 1% threshold;
- Include the avoided cost components for transmission capacity, distribution capacity, and ancillary services be included in Rider SQF, effective with the rates approved in this proceeding;
- Include compensation for avoided distribution costs that occur throughout the Companies' distribution system, including for those parts of the distribution system placed in service prior to the start of Rider NMS-2;
- The Companies conduct an updated and comprehensive marginal distribution capacity cost study that accounts for circuit- and infrastructure-level variations in non-coincident peaks and is based on a robust and statistically valid sample of customers;
- Retain the existing avoided cost components for Rider NMS-2 and compensate customer-generators based on re-calculated current values;

- Battery-coupled DG resources be included in the Companies' Rider NMS-2 and QF Tariffs, with appropriate price signals, and that the Commission consider the resilience benefits offered by these systems to all ratepayers in its evaluation of a just and reasonable compensation rate for net metering exports.

Q. **PLEASE IDENTIFY ANY EXHIBITS YOU ARE SPONSORING?**

A. I am sponsoring the following Exhibits:

- Exhibit JWH-1 – CV of Jason W. Hoyle
- Exhibit JWH-2 – CONFIDENTIAL Variable Minor Maintenance Cost calculation example for 2026

II. <u>AVOIDED COST RATES AND QUALIFYING FACILITY TARIFFS</u>

A. Evaluation of the Companies' Proposed Avoided Cost Rates

Q. **PLEASE BRIEFLY SUMMARIZE THE COMPANIES' PROPOSALS REGARDING AVOIDED COST RATES.**

A. The Companies propose avoided cost rates expressed as a $/MWh price for a 2- or 7-year Power Purchase Agreement ("PPA") term, and the Companies propose that these rates be offered to some Qualifying Facilities ("QFs") and that some QFs not be offered a 7-year price or be eligible to enter into a PPA. The proposed avoided cost rates for a 7-year PPA vary based on the beginning year of the PPA, i.e. 2026 or 2027. The proposed avoided cost rates also vary based on QF technology, with a separate rate for solar with single-axis tracking ("Solar SAT"), solar with a fixed tilt ("Solar FT"), Wind, and Other. The proposed rates were also adjusted for line losses based on whether a QF is interconnected to the distribution or transmission system. The proposed avoided cost rates for each combination of PPA term, technology type, and interconnection type are not differentiated by season or by hour and are expressed as a single levelized value in units of $/MWh.

Q. DOES THE COMPANIES' APPROACH TO CALCULATING THE AVOIDED ENERGY COST COMPONENT INCLUDE ALL GENERATION-RELATED COSTS?

A. No. The Companies' calculation of "[a]voided energy costs include the cost of fuel, emission control reagents (e.g., limestone, ammonia), emission allowance costs, and an opportunity cost for lost CCR revenues."[1] The Companies' avoided energy cost calculations do not include variable operations and maintenance costs associated with the repair, overhaul, replacement, or inspection of a generating resource. As explained by Companies' Witness Schram, "The only variable operating and maintenance costs included in avoided energy costs are costs for consumables to operate emission control equipment. Other operating and maintenance costs are excluded because they are fixed costs and do not vary with the operation of the unit."[2]

The Companies avoided energy costs only include variable operating costs and exclude variable maintenance costs that are incurred as a result of electricity production operations. The PJM Interconnection considers variable operations and maintenance ("VOM") costs as including three distinct components[3] – major maintenance, minor maintenance, and operating costs – yet the Companies' avoided energy costs exclude the two categories of VOM costs related to maintenance. These are significant as PJM's default values, effective January 1, 2025, for minor maintenance costs alone are

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[1] Schram Direct, Exhibit CRS-6 at 3.
[2] Companies' Response to KYSEIA Supplemental Request for Information at Q-2.
[3] PJM Interconnection. 2024 VOM Education Session. April 16, 2024. https://www.pjm.com/-/media/DotCom/committees-groups/forums/tech-change/2024/20240416/20240416-item-03---4---cost-agent-introduction.pdf at 3.

$4.43/MWh for a simple-cycle combustion turbine, $2.11/MWh for a fossil steam turbine, and $1.21/MWh for a combined cycle unit.[4] Major maintenance costs (i.e., maintenance activities that require unit disassembly, or the replacement or overhaul of major components) are also incurred in addition to minor maintenance costs.

Q. WHY ARE THESE MAINTENANCE COSTS CONSIDERED VARIABLE COSTS?

A. Any maintenance costs that are incurred based on operating hours or are directly related to electricity generation are variable costs and should be included in the calculation of avoided energy costs. Much like an automobile that needs an oil change or a fuel filter replacement every so many miles, mechanical generation units such as turbines or engines also require maintenance on a schedule defined by usage. Similar to PJM, the California ISO also includes maintenance in VOM costs and considers these to be costs that vary with electricity production, whether start-up/shut-down, run hours, or electricity output.[5] The Southwestern Power Pool tariff added variable maintenance costs in 2018, which were described in the FERC Order as "major maintenance costs will be a variable cost component of the mitigated offer and will be directly related to both the decision to start a resource and/or the number of hours the resource is operated."[6]

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[4] PJM Interconnection. 2024 VOM Education Session. April 16, 2024. https://www.pjm.com/-/media/DotCom/committees-groups/forums/tech-change/2024/20240416/20240416-item-03---4---cost-agent-introduction.pdf at 6.

[5] California ISO. Variable Operations & Maintenance Cost Review. October 14, 2021. https://www.caiso.com/documents/presentation-variable-operations-maintenance-cost-review-training.pdf at 13.

[6] 165 FERC 61,026. Order dated October 18, 2018. https://www.ferc.gov/sites/default/files/2020-05/E-9_48.pdf at 2.

Q. SHOULD VARIABLE MAINTENANCE COSTS BE INCLUDED IN AVOIDED ENERGY COST?

A. Yes. There are variable maintenance costs that accrue based on generator activity, typically operating hours. Other variable costs such as fuel and reagent consumption that are incurred based on generator activity are included in the avoided energy cost and variable maintenance costs should be as well because they are the direct result of the same generator activity. One approach that could be implemented immediately, that I recommend, with little additional effort required of the Companies' is to apply PJM's default variable maintenance costs for minor maintenance based on the Companies' share of generation by technology type, essentially a weighted-average variable minor maintenance cost, and add that to the avoided energy cost. This approach would produce a single variable maintenance cost, in $/MWh units, based on the Companies' generation profile using the best available variable maintenance cost information.

Q. HAVE YOU CALCULATED VARIABLE MAINTENANCE COSTS?

A. Yes. My calculations of variable minor maintenance costs for 2026 resulted in average variable maintenance costs for minor maintenance of $2.08/MWh. These calculations are shown in Confidential Exhibit JWH-2.

To calculate this cost, I used the default PJM minor maintenance costs I previously discussed for the following technology types: combustion turbines ("CT"), fossil steam turbines ("ST"), combined cycle units ("CC"), and internal combustion engines ("ICE"). I used the 2026 projected generation for each of the Companies' generating units shown in the Companies' confidential generation forecast attached to

Exhibit CRS-7 of Witness Schram's testimony in file named "out_unityr.csv". I obtained the type of generating unit from the Energy Information Administration Form 860.[7]

Q. DO YOU HAVE OTHER CONCERNS REGARDING THE COMPANIES' APPROACH TO DETERMINING THE ENERGY CREDIT?

A. Yes. Because the proposed energy credit has no seasonal or time differentiation, they do not provide a price signal to which customers may respond. If a solar QF generates electricity exactly in line with the Companies' profile, then the solar QF will receive the full value of the generation it is offsetting. However, a solar QF that exports only a portion of its output to the Companies may not receive the full value of the generation it is offsetting, especially if its export profile is weighted more towards hours with higher generation costs, such as peak hours.

QFs and net metering customers that consume a portion of the generation from the systems they own and sell their surplus generation to the Companies typically have some control over when they consume what portion of their generation and, as a result, the share of their generation that is sold to the companies. Generally speaking, summer afternoons will have a higher generation cost to the Companies and all its customers than during summer mornings, with winter being opposite. The most basic temporal differentiation in pricing for export compensation would provide higher energy credit compensation during summer afternoons than it would for exports during summer mornings.

Even a simple price signal, like higher export compensation prices for summer afternoons and winter mornings, has the ability to influence behavior. Customer response

[7] https://www.eia.gov/electricity/data/eia860/

to such a price signal may be as basic as a net metering customer doing laundry and running the dishwasher on summer mornings instead of afternoons, or on winter afternoons instead of mornings, would add a greater share of exports during the hours when utility generation costs were higher. The difference between whether a net metering customer pushes the start button on an appliance before going to work in the morning or upon returning from work in the afternoon is likely of little consequence to the customer-generator, but could have meaningful effects on the portion of their generation that is exported during the hours with the highest generation cost. I recommend the Commission consider some basic price differentiation in the energy credit compensation structure.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANIES' PROPOSALS REGARDING AVOIDED GENERATING CAPACITY COST.

A. The Companies describe their avoided capacity cost "as a function of the QF PPA's contribution to the timing and size of the Companies' future need for capacity and the cost of new capacity."[8] The Companies' "capacity need is assumed to be immediate, in 2026"[9] and as shown in Appendix A to Exhibit CRS-6 the 2026 winter capacity need is 137 MW and the summer 2026 capacity need is 96 MW. [10] Although the Companies' forecast shows they will continue to be summer peaking through 2032, the peak load forecast trend shows growth in the winter peak and an ongoing winter capacity need through 2032 in each year except 2028.[11]

[8] Schram Direct, Exhibit CRS-6 at 5.
[9] Schram Direct, Exhibit CRS-6 at 7.
[10] Schram Direct, Exhibit CRS-6 at 13-14.
[11] *Id*.

The Companies determine the peak capacity contribution of each resource type for summer and winter, with solar assigned 84% and 0% for summer and winter, respectively; wind is assigned 11% and 35% contribution to peak for summer and winter, respectively.[12] Although they acknowledge the capacity contribution to summer and winter peaks for both solar and wind technologies, "the Companies recommend the avoided capacity cost for single-axis tracking solar, fixed tilt solar, and wind QF PPAs be zero."[13]

The Cane Run BESS, considered as an "Other" technology type, is recommended "as the cost of new capacity to calculate avoided capacity costs."[14] Because they consider the "Other" QF technology type to be fully dispatchable, the Companies adjust the $/MW-year economic carrying cost of the Cane Run BESS to reflect a fully dispatchable "Other" technology.[15] Even with the Stipulation reached in Case No. 2025-00045 and the withdrawal of the Cane Run BESS request, the Companies continue to assert that the Cane Run BESS is the cost of new capacity.[16]

Q. IS THE CANE RUN BESS A REASONABLE BASIS FOR DETERMINING THE AVOIDED CAPACITY COST?

A. Possibly, but only if the corrections I describe below to the methodology for determining a $/MWh value are adopted. The Commission's Order in the Companies' most recent avoided cost proceeding used the cost of a combined cycle unit.[17] The costs of natural gas

[12] Schram Direct, Exhibit CRS-6 at 5.
[13] Schram Direct, Exhibit CRS-6 at 7.
[14] *Id*.
[15] Schram Direct, Exhibit CRS-6 at 7-8.
[16] Companies' Response to KYSEIA Supplemental Information Request at Q-12(d) and (e).
[17] Case No. 2023-00404, Order dated August 30, 2024, at 19.

combustion turbines are also commonly used for this purpose. Additionally, it is appropriate and prudent to note, given that the Companies' practice of engaging in off-system sales presents an opportunity cost, that capacity prices in the PJM Interconnection's July 2025 auction cleared at the Federal Energy Regulatory Commission ("FERC")-approved price cap of $329.17/MW-day (UCAP) for the entire PJM footprint – this is the capacity price in the 2026/2027 Base Residual Auction.[18]

Q. HAVE YOU IDENTIFIED ANY PROBLEMS RELATED TO HOW THE AVOIDED CAPACITY COST IS DETERMINED USING THE CANE RUN BESS ?

A. Yes. I identified two primary issues with how the avoided capacity cost is determined in the Companies' proposal. The first issue relates to the nature of batteries' charge-discharge cycle and the method used to convert the $/MW-year value into a $/MWh price. The second issue is the lack of seasonally differentiated capacity payments, which at the very least should compensate QF exports or exports under Rider NMS-2 for output during the Companies' peak seasons of summer and winter at a rate ($/MWh) sufficient for the generator to recover the full capacity cost (i.e., $/MW-year) if the generator operates at a 100% capacity factor, or its full output, during those times.

The Cane Run BESS was assumed to have a capacity contribution of 83% and the capacity contribution is adjusted to reflect a 100% capacity contribution by multiplying the Cane Run BESS economic carrying charge by 120%.[19] This adjustment converts the

[18] PJM Interconnection Press Release. July 22, 2025. https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250722-pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal.pdf

[19] Schram Direct, Exhibit CRS-6 at 8: footnote 14.

capacity price of a unit with an 83% contribution into its equivalent price for a unit with a 100% contribution.

The first problem arises in how that annual avoidable cost in $/MW-year is converted into a $/MWh price. To convert the $/MW-year into the $/MWh avoided capacity cost offered to Other technology-type QFs, the annual $/MW-year value is "divided by 8,760 hours."[20] As a result of this conversion, a QF would need to operate at full output for all 8,760 hours in a year to receive the full capacity payment. Nuclear facilities typically have the highest capacity factor of all utility-scale generator types and nuclear facilities only reach an average of about 92% or 93% capacity factor.[21] Requiring a QF to operate at full output in every hour of the year to receive the full capacity payment is highly discriminatory against QFs and unreasonable. Commonly, avoided cost rates define peak energy hours for peak capacity months and set a capacity payment so that a QF operating at full output during all of those hours in those months would receive the full $/MW-year avoided cost capacity payment.

The Companies' methodology to convert $/MW-year capacity values into a $/MWh payment would not allow the Companies to recover the full capacity costs of the Cane Run BESS if the Companies were compensated for that unit under the methodology they propose for QFs. Battery resources have limited-duration discharge, typically 4-, 6-, or 8-hours, after which the battery must be recharged over a similar time period if both charged and discharged at the maximum rate. Assuming an equal time is required for charging and discharging, the maximum number of hours in a year a battery could

[20] Schram Direct, Exhibit CRS-6 at 8.
[21] EIA. Electric Power Monthly.
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b

discharge at its full output is 4,380 hours.[22] Under the Companies proposed capacity compensation methodology, the Companies would need to earn approximately \$35.52/MWh[23] if the Cane Run BESS discharged at full output for the maximum number of hours in a year, and because there is a variable cost associated with generating the electricity needed to recharge the battery it is highly unlikely that the Cane Run BESS or any other battery – or peaking-type capacity resource, for that matter – would discharge at full output for the maximum number of hours in a year.

The Companies' combined peak load is in summer currently, and they have an identified capacity need in summer 2026. Additionally, the Companies' also have a winter capacity need starting in 2026 that is ongoing.[24] The forecast trend overall shows the difference between winter and summer peak load is expected to shrink. Capacity payments under the Companies' proposal are for a flat \$/MWh rate paid in all hours of the day in all months of the year, which is a price signal that discourages QFs and Rider NMS-2 customer-generators from ***prioritizing*** capacity contributions. The capacity payment is not structured in any way to reflect so much as the months during which the Companies experience peak load. A proper price signal for the capacity payment would, at a minimum, offer the capacity payment during the months when the Companies' experience peak loads.

Instead of offering the capacity payment in all months as the Companies propose, a more effective price signal to encourage QFs and Rider NMS-2 customers to provide the Companies capacity would be to offer the capacity payment during winter and

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[22] 8,760 hours * 50% = 4,380 hours

[23] Based on 7-year capacity price for 2026 project. Calculated as \$17.76 / 0.5 = \$35.52.

[24] Schram Direct, Exhibit CRS-6 at 13-14.

summer months. As an example, assuming winter and summer are defined as 3 months each for a combined 6 peaking months, based on the battery charging-time requirement adjustment of a maximum 4,380 hours/year discharge, a simple explanatory adjustment is to divide those hours by half and for the 6-month capacity payment term the battery is capable of fully discharging for 2,190 hours during the 6-month peak load window. So, using the same simplified method, the adjusted price to maintain the full $/MW-year payment is $71.04/MWh.[25]

In this simplified example, the annual payment doesn't change but rather the annual payment is distributed over fewer hours and more concentrated during peak load months. It could be more focused by applying a set of peak hours during winter and summer months. For instance, a 6-hour peak window is 25% of a day, and if the capacity payment was offered only for 6 hours a day for six months a year the $71.04/MWh becomes $142.08/MWh.[26,27] That sounds very high compared to the Companies' proposed price which requires a generator to operate at full output for all 8,760 hours in a year to receive the full $/MW-year capacity payment, but in this somewhat simplified demonstrative example the generator only has to operate at full output for 1,095 hours[28] – hours during which the Companies experience peak load.

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[25] $35.52 / 0.5 = $71.04

[26] $71.04 / 0.5 = $142.08

[27] Note that the adjustment to account for charging time was removed since the battery can recharge outside the 6-hour peak window. However, if the price is based on a 4-hour battery, a replacement adjustment would need to be applied since the Companies' 4-hour battery could only discharge for 4 of the 6 hours at maximum output and the full $/MW-year should be recoverable based on a price that would allow the Companies to recover the levelized annual cost.

[28] 8,760 hours * (.5 * .25) = 1,095 hours

Q. PLEASE EXPLAIN HOW THE COMPANIES ACKNOWLEDGE THAT SOLAR AND WIND TECHNOLOGIES CONTRIBUTE TO SUMMER AND WINTER PEAK CAPACITY NEEDS, YET RECOMMEND THOSE QF TECHNOLOGIES RECEIVE NO AVOIDED CAPACITY PAYMENT?

A. The Companies justification for a $0 avoided capacity value for solar and wind technologies is their conclusion that "80 MW QF PPAs of single-axis tracking solar, fixed-tilt solar, and wind do not result in any changes to the Companies' optimal resource plan."[29] This justification is unsupported by the Companies' own statements that solar technologies have a capacity contribution of 84% in summer and wind technologies have a capacity contribution of 11% and 35% in summer and winter, respectively.[30]

In addition to their acknowledgement of a capacity contribution by solar and wind technologies, the Companies have also acknowledged a capacity need in starting 2026 and extending into future years,[31] which following "the Stipulation reached in Case No. 2025-00045, the Companies will delay Mill Creek 2's retirement and are withdrawing their request for the Cane Run BESS."[32] It is clear that there is both an immediate and ongoing capacity need and that the Companies acknowledge a capacity contribution from solar and wind technologies.

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[29] Schram Direct, Exhibit CRS-6 at 7.
[30] Schram Direct, Exhibit CRS-6 at 5.
[31] Schram Direct, Exhibit CRS-6 at 13.
[32] Companies' Response to KYSEIA Supplemental Request for Information, at Q-12(d).

Q. HAVE THE COMPANIES IDENTIFIED CAPACITY NEEDS THAT COULD BE MET BY SOLAR AND WIND TECHNOLOGIES?

A. Yes. The Companies have identified a 96 MW[33] capacity need in summer 2026, and winter capacity needs starting in 2026 and continuing throughout the 7-year period.[34] However, the Companies did not propose to include an avoided capacity payment for solar and wind technologies. It is unclear to me why the 2026 summer and winter capacity need, at the minimum, was not considered, but according to the Companies, "The Companies are not planning resources to meet the capacity need during the transition year of 2026 due to the lead time required to bring new resources into service."[35]

The Companies' justification for a $0 capacity component for solar and wind QFs is based on a resource planning modeling result that shows no "changes to the Companies' optimal resource plan." Modeling results are dependent on and influenced by inputs and assumptions used in the modeling. For example, the Companies added 80 MW of QF solar in modeling scenarios, and the two PLEXOS scenarios that resulted in an optimal portfolio that included 815 MW of solar without the QF solar also resulted in optimal portfolio with 815 MW of solar with the QF solar.[36]

In the Companies' evaluation of QF capacity value, "80 MW of each QF technology was added to the Companies' currently approved resource portfolio in PLEXOS, and resulting optimal resource plans were compared to the portfolio with no

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[33] Schram Direct, Exhibit CRS-6 at 14.
[34] *Id*. at 13.
[35] Companies' Response to KYSEIA Supplemental Request for Information at Q-12(a).
[36] Schram Direct, Exhibit CRS-6 at 6.

QF PPAs."[37] 80 MW of wind multiplied by 35% is 28 MW of winter capacity contribution, yet the modeling shows no change, likely due to the size, in MW, of different selectable resource types in the model. For example, 28 MW of winter capacity from wind may not displace or delay a 100 MW gas turbine if only 80 MW of wind is added and only a 100 MW gas turbine is selectable. However, based on the Companies' actual identified capacity needs, 28 MW of winter capacity from wind is larger than the identified capacity need in 2027, 2029, and 2030.

Consider a solar QF paired with battery storage that was exclusively charged with solar output. Such a solar QF would be capable of fully discharging the battery during peak winter mornings, even when the Sun wasn't shining. Yet, the Companies' proposal does not consider, address, or otherwise account for this increasingly common technology configuration. The Companies did, however, suggest the possibility of non-Other QFs (i.e. solar and wind) co-located with a battery energy storage system being eligible for compensation under the "Other" QF technology type, stating "Such QFs were not explicitly evaluated; however, such a facility may fit within the "Other Technologies" category of QFs, depending on the characteristics of the generation profile."[38] I recommend the Companies clarify the circumstances under which they propose a solar or wind QF or Rider NMS-2 customer-generator would be compensated based on the "Other" QF technology type and adjust the QF tariffs and Rider NMS-2 rates accordingly.

[37] *Id*.
[38] Companies' Response to KYSEIA Initial Request for Information at Q-21(b).

Avoided costs are not defined by how much a QF can influence the Companies' planning model results, but rather avoided costs are set at a price based on utility costs so ratepayers are indifferent. As defined in 807 KAR 5:054 Section 1(a), avoided costs mean "incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source." The costs of resources in the Companies' optimal resource planning portfolio could be used to determine the value or price of avoided cost components paid to the QF – there are other methods – but the results of the resource planning model that is influenced by input assumptions and a variety of constraints, some of which may be arbitrary or otherwise disconnected from reality, clearly do not capture the potential contribution of QF resources when the Companies' own analysis shows a capacity need in future years that is less than the capacity contribution of a single 80 MW wind QF, or the un-modeled solar paired with storage QF.

Q. ARE YOU SUGGESTING THAT A CAPACITY CREDIT SHOULD ONLY BE PAID WHEN THE COMPANIES' PLANNED RESOURCE PORTFOLIO DOES NOT FULFILL THEIR FUTURE CAPACITY NEEDS?

A. No. A capacity credit should be included whenever the Companies have identified a future capacity need, regardless of whether the Companies have a plan to meet that need or whether the Companies' resource plan doesn't fulfill the future need. If the Companies have an identified capacity need in 5 years, then a capacity credit should be paid in each year starting from the time the future need is identified.

Q. DO YOU HAVE OTHER CONCERNS WITH THE COMPANIES' APPROACH TO EVALUATING AVOIDED CAPACITY COSTS?

A. Yes. In addition to the above concerns, the Companies put forth a convoluted and unreasonable justification for their proposed $0 capacity payment for wind and solar technologies that does not carry out the very concept of an avoided cost capacity payment. Possibly the Companies' proposal is in response to the Commission's Order in the Companies' most recent avoided cost proceeding which ordered that "LG&E/KU shall file additional evidence and testimony for the reasonableness of zero avoided capacity costs in its next base rate case."[39]

The Companies' proposal to provide no capacity payment to wind and solar technologies directly contradicts the facts presented in their proposal. As previously discussed, the Companies identify an immediate capacity need – even a capacity need they don't intend to address in 2026 – in summer 2026 and winter that extends through the 7-year avoided cost term, and the Companies' estimates of solar and wind capacity contributions align with the identified capacity needs. A compelling case for providing capacity payments to solar and wind QFs and for Rider NMS-2 exports does not get much more clear or basic.

Additionally, there is still capacity value during summer months of years beyond 2026 as well in the form of an opportunity cost that the Companies could capitalize on as QF capacity could support off-system sales of the Companies' capacity resources to support reduced costs for all the Companies' ratepayers, which is potentially a very

[39] Case No. 2023-00404, Order dated August 30, 2024, at 24.

lucrative opportunity at present given the high capacity prices in PJM's most recent auction.

The Companies' argument is that the results of their resource planning model do not change with the addition of a single wind or solar QF. Yet, their optimal resource portfolio clearly doesn't cover the Companies capacity needs as demonstrated in Appendix A to Exhibit CRS-6. Even if the Companies' planned resources did cover their future capacity needs, that would simply indicate future capacity needs and costs to which solar and wind QFs or Rider NMS-2 exports could contribute, which is the basis for the avoided capacity cost compensation. Resource modeling results could provide information on which technology type to base the avoided capacity cost and to demonstrate there are future capacity needs.

As Witness Schram described, "Because 80 MW QFs for single-axis tracking solar, fixed tilt solar, and wind have no impact on the Companies' optimal resource plan, I recommend the avoided capacity cost of these technologies be zero."[40] This recommendation was further reiterated in Exhibit CRS-6, with the recommendation that "the avoided capacity cost for single-axis tracking solar, fixed tilt solar, and wind QF PPAs be zero" based on QF modeling results shown Table 5 of Exhibit CRS-6 that "do not result in any changes to the Companies' optimal resource plan" in its 2025 CPCN Plan.[41] Yet, as I previously discussed, 80 MW of wind multiplied by the Companies' assumed 35% winter wind capacity contribution is 28 MW of winter capacity contribution, and the Companies have a winter capacity need identified in Appendix A of

[40] Schram Direct at 35: 14-16.
[41] Schram Direct, Exhibit CRS-6 at 6-7.

Exhibit CRS-6 that a single 80 MW wind QF would contribute to and would fully meet in 3 years. Clearly adding an 80 MW wind QF did not alter the optimal resource plan when it obviously should have because the optimal resource plan is not fulfilling the Companies' capacity needs. Likewise, a solar system paired with storage could not alter the optimal resource plan because it wasn't considered, even though a single such QF could also meet the Companies' capacity needs.

Finally, I will emphasize that the determination of whether to include avoided capacity cost compensation is not dependent on a single QF project altering the results of a planning model. The mere fact that the planning model shows the need for future capacity procurement is all the supporting basis necessary to reasonably and justly include compensation for avoided capacity costs to QFs and for Rider NMS-2 exports.

Q. PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANIES' AVOIDED CAPACITY COST PROPOSAL.

A. In summary, my conclusions about the Companies' proposal for avoided capacity costs are the following:

- The proposed methodology for determining the $/MWh price paid to QFs is flawed and as proposed would neither allow the Companies to recover the full costs of the resource, nor compensate QFs or Rider NMS-2 customer-generators fully for their capacity contributions.
- The proposed pricing structure for capacity compensation is completely unrelated to the seasonality and timing of peak loads, provides no price signal to influence market participants' decisions, and likely provides a price signal that would discourage market participants from options to increase their capacity contributions during peak load times.

- The Companies have demonstrated an immediate and ongoing capacity need which could be fully or partially met by all types of QFs – including solar during winter if paired with a battery.

B. Evaluation of the Companies' Proposed QF Tariffs

Q. PLEASE BRIEFLY DESCRIBE THE COMPANIES' PROPOSALS REGARDING QUALIFYING FACILITY TARIFFS.

A. The Companies propose several modifications to QF tariffs Rider SQF and Rider LQF. The first proposed modification only allows a QF to enter into a PPA with the Companies if the QF sells its "entire output" and is "purchasing all of [the QF's] own requirements from" the Companies,[42] which is what would be commonly termed a buy-all/sell-all structure. The Companies proposed no changes to tariff terms under which compensation to the QF for capacity contributions require the QF to enter into a PPA.[43] With this combination of tariff terms, QFs are prevented from entering into a PPA with the Companies if the QF uses the output of its own generation system to meet its own behind-the-meter ("BTM") power demand, QFs serving a BTM load would not be compensated for their capacity contribution for the portion of generation sold to the

[42] For Rider SQF, see Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 106 of 216 Hornung and Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 104 of 215 Hornung For Rider LQF, see Case No. 2025-00113 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 110 of 216 Hornung and Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 108 of 215 Hornung.

[43] For Rider SQF, see Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 107 of 216 Hornung and Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 105 of 215 Hornung For Rider LQF, see Case No. 2025-00113 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 111 of 216 Hornung and Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 109 of 215 Hornung.

Companies, and QFs serving a BTM load would be denied the ability to receive the fixed long-term prices under 7-year PPA terms.

Additionally, the Companies proposed to change the circumstances under which a QF could hold the Companies accountable "for injury or damage to persons or property" from the current standard of "negligence of the Company" to the higher standard of "Company's gross negligence or willful misconduct is the sole and proximate cause of said injury or damage."[44]

Q. WHAT PROBLEMS HAVE YOU IDENTIFIED IN THE COMPANIES' PROPOSED CHANGES TO QF TARIFFS?

A. There are several problems. The proposed changes to the terms of Rider SQF and Rider LQF (collectively "QF Tariffs") prevent QFs that supply their own BTM load from entering into PPAs, and without a PPA QFs with a BTM load are not eligible to receive the fixed long-term price offered only under a 7-year PPA nor are they eligible for capacity payments.

While I am not an attorney and am not offering legal conclusions, an examination of Kentucky's implementation of PURPA in 807 KAR 5:054 Section 6(1), in terms of its policy objectives and ratemaking instructions, requires electric utilities to "purchase <u>any energy and capacity which is made available</u> from a qualify facility" (emphasis added). There is no basis in 807 KAR 5:054 for discriminating against QFs that supply some or

[44] For Rider SQF, see Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 109 of 216 Hornung and Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 107 of 215 Hornung For Rider LQF, see Case No. 2025-00113 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 113 of 216 Hornung and Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 111 of 215 Hornung.

all of their own power needs and only make available for purchase by the utility a portion of the QF output, likewise there is no carve-out or exception that limits the utility obligation to purchase both energy and capacity to only those QFs who agree to sell all the facility's output to the utility and agree to purchase all the power the facility requires from the utility. 807 KAR 5:054 Section 6(5) requires electric utilities to "sell power to a qualifying facility <u>upon request</u>" (emphasis added) and 807 KAR 5:054 Section 7(7) goes further in requiring electric utilities to "provide supplementary power, back-up power, maintenance power, and interruptible power" "[u]pon request by a qualifying facility."

Specifically, in terms of policy objectives and instructions, this utility obligation to sell power to a QF upon the request of a QF includes the following:

- Back-up power,[45] which is energy or capacity from the utility to "replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility."
- Maintenance power,[46] which is energy or capacity "supplied by an electric utility during scheduled outages of the qualifying facility."
- Supplementary power,[47] which is "energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself."

These specific types of power an electric utility is obligated to sell to QFs – when requested by the QF – clearly relate to QFs which use a portion of their generation to meet their own BTM power requirements. 807 KAR 5:054 Section 7(1) provides the QF

[45] 807 KAR 5:054 Section 1(2).
[46] 807 KAR 5:054 Section 1(6).
[47] 807 KAR 5:054 Section 1(11).

with the option of supplying power for its own needs and selling surplus generation, or selling their entire output to the utility while simultaneously purchasing all their power requirements from the utility. The policy objectives are straightforward.

Q. IS THE CONCERN THAT THE COMPANIES PROPOSE NOT TO FULFILL THEIR OBLIGATION TO SELL POWER TO QFS?

A. No. One problem with the Companies' proposed changes to their QF Tariffs is that the proposed changes impose a mutually exclusive tradeoff between the utility obligation to purchase and the utility obligation to sell. The rates[48] for the utility purchase of QF output must be "subdivided into an energy component and a capacity component"[49] and utilities are required to offer rates to purchase QF power "offered on an 'as available' basis based on avoided cost estimated at the time of delivery" and also to offer rates to purchase QF power "offered on all legally enforceable obligations" which are required to include a capacity component and which must "be based at the option of the qualifying facility on either rates avoided costs at the time of delivery or avoided costs at the time the legally enforceable obligation is incurred."[50]

Under the Companies' proposed changes to the QF Tariffs, if a QF exercises its option under 807 KAR 5:054 Section 7(1)(a) to power its BTM load and sell its surplus output to the utility, that QF is forced to accept the as-available[51] utility purchase rates and is denied its choice of the rate options under 807 KAR 5:054 Section 7(2)(b) for

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[48] See 807 KAR 5:054 Section 7(2) for Rider SQF and 807 KAR 5:054 Section 7(4) for Rider LQF.
[49] *Id*.
[50] See 807 KAR 5:054 Section 7(2) for Rider SQF and 807 KAR 5:054 Section 7(4) for Rider LQF.
[51] See 807 KAR 5:054 Section 7(2)(a) for Rider SQF and 807 KAR 5:054 Section 7(4)(a) for Rider LQF.

Rider SQF and 807 KAR 5:054 Section 7(4)(b) for Rider LQF. All QFs have the option to determine the disposition of their facility's output, i.e. whether to sell it all or to use some to meet their own power requirements, and all QFs have the option to choose between the rate options for the utility purchase of their output, i.e. on an as-available basis or pursuant to legally enforceable obligation.

The Companies' proposals prevent QFs that exercise the option to supply their own power needs (i.e., BTM QFs) from also exercising the QF's choice of purchase rate options. Additionally, BTM QFs are denied access to rates enabling them to sell capacity to the utility by virtue of having exercised their choice to meet their own power requirements and sell surplus output to the utility. By denying BTM QFs the ability to exercise the full suite of options available to them, the Companies proposed changes to their QF Tariffs are not just or reasonable because they do not fulfill the utilities' purchase obligations under 807 KAR 5:054 and discriminate against BTM QFs.

Q. ARE YOU AWARE OF ANY AVOIDED COST TARIFFS THAT EXCLUDE BTM QFS FROM RECEIVING CAPACITY PAYMENTS FOR POWER EXPORTS?

A. No. Although "The Companies have not performed this research,"[52] I reviewed multiple QF tariffs from utilities in nearby states and identified no terms that exclude BTM QFs, solely due to their BTM use of their own generation, from receiving capacity compensation and that did not allow BTM QFs to enter into PPAs. The tariffs I reviewed

[52] Companies' Response to KYSEIA Initial Request for Information at Q-8.

include: Ameren Illinois,[53] ComEd (Illinois),[54] MidAmerican Energy (Illinois),[55] NIPSCO (Indiana),[56] Indiana-Michigan Power (Indiana),[57] Duke Energy Indiana,[58] Duke Energy Kentucky,[59] Ameren Missouri,[60] Evergy Missouri Metro,[61] AEP Ohio,[62] Duke Energy Ohio,[63] Appalachian Power (West Virginia),[64] and Potomac Edison (West Virginia).[65]

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANIES' PROPOSED QF TARIFFS.

A. Yes. The Companies' proposed QF Tariffs only allow a QF that has entered into a PPA to receive the typically higher avoided cost payments for a 7-year term and to receive

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53 https://www.ameren.com/-/media/rates/files/illinois/aiel28rdqf.ashx.

54 https://www.comed.com/cdn/assets/v3/assets/blt3ebb3fed6084be2a/blt86ebee5fe6ed02f8/6866e86afa0c450033ffa359/2025_Ratebook.pdf?branch=prod_alias at 443-449.

55 https://www.midamericanenergy.com/media/pdf/il-electric-tariffs.pdf at 462-468.

56 https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/electric-rates/2023-to-current/rider-578.pdf?sfvrsn=f2b4e851_1.

57 https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IMINTB2006-30-2025.pdf at 120-124.

58 https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-in/iurc-16/tariff-no-50-rate-qf-parallel-operation.pdf?rev=6149caa2a21f4be693dc2c8aa7789ed2.

59 https://www.duke-energy.com/-/media/pdfs/rates/ky/sheetno93cogen.pdf?rev=32abd47c30274ec9a570351dd5ad2c55 and https://www.duke-energy.com/-/media/pdfs/rates/ky/sheetno94cogenkyelec.pdf?rev=75828bb6f02a4adc96f34e8483c2d69c.

60 https://www.ameren.com/-/media/rates/files/missouri/uecsheet170eppqfcogen.ashx.

61 https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/parallel-generation-contract-service.pdf.

62 https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/August_2025_AEP_Ohio_Tariff_Book.pdf.

63 https://www.duke-energy.com/-/media/pdfs/rates/oh/sheet-no-93-cogen-oh-e.pdf?rev=67efcfddc7824fd0941416aa2eccce21.

64 https://www.appalachianpower.com/lib/docs/ratesandtariffs/WestVirginia/LargeLoadTariffSheetsEff3-25-25_002.pdf at 89-91.

65 https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/west-virginia/tariffs/WVPERetailTariff.pdf at 73-74.

capacity payments, and the Companies' proposed changes to their QF Tariffs only allow QFs who agree to purchase all their power requirements from the utility and sell all their generation to the utility to enter into a PPA.

The Commission's Order addressing Riders SQF and LQF in the Companies' previous rate case found that a 7-year PPA for QFs was "sufficient to provide price certainty to QF developers, is sufficient for obtaining financing for QF projects, and represents a reasonable balance of associated risk for ratepayers, developers, and the utility"[66] and also found that "the 2- year QF contract term is just and reasonable, and, therefore, should be approved as it provides a reasonable alternative for QFs that do not want a longer-term commitment."[67]

In these cases, the Companies propose eliminating PPAs completely for some QFs, which would increase some QF developers' exposure to price risk, undermine some QF developers' ability to obtain financing, and impose an unreasonable imbalance of risk that heavily favored the utilities while increasing the risks allocated to ratepayers and developers.

While the Companies have not justified their proposal to eliminate PPAs entirely for some QFs, they appear to be conflating different aspects of common PPA terms. For example, PPA contracts commonly specify a length of time,[68] in years, the utility will

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[66] Case Nos. 2020-00349 and 2020-00350, Order dated September 24, 2021, at 28.
[67] Case Nos. 2020-00349 and 2020-00350, Order entered September 24, 2021,at 27.
[68] See Section 3.1 at 21 of https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/industry-services/QF-Standard-Offer-Contract-Proxy-PPA-2021.pdf and Section 2.1 at 13 https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Power_Purchase_Agreement_for_Qualifying_Facilities_up_to_10_MW.pdf

purchase power from the QF under the PPA. This length of time is separate from and distinct from the clauses establishing the prices for the sale of energy and capacity by the QF and other clauses which may define QF capacity obligations or capacity commitments, annual generation forecasts, etc. These common clauses in PPA contracts serve different purposes.

For instance, a QF may choose to sell its energy and capacity at the avoided cost determined at the time of delivery (i.e., as-available rate) that would generally change every two years, particularly if the QF projected the utility had a need for increasingly high-cost new capacity or expected the energy portion of avoided cost rates to increase, but that same QF would also want to know all the other terms and conditions that applied to the utility's purchase of its output and have the certainty regarding those other terms and conditions that could only be obtained from a PPA with a defined term length of multiple years. To wit, a QF's preference or choice of an avoided cost sale price that changed every two years should not be conflated with a QF's requirement to make such sales according to contractual terms that are fixed over a much longer number of years.

The Companies' efforts to deny QFs access to contractual terms are not only unreasonably prejudicial against QF developers but are also contradictory to the utility obligations in multiple sections of 807 KAR 5:054 and render the Commission's authority to review and approve such contracts meaningless. 807 KAR 5:054 Section 7(3) requires electric utilities to "offer a standard contract to qualifying facilities with a design capacity of 100 kW or less" and clearly states that "This contract shall be subject to commission approval." 807 KAR 5:054 Section 7(5)(a) includes dispatchability, reliability, "terms of contract, duration of obligation, termination requirements, ability to schedule coordinated outages", etc. as factors a utility "should consider" in determining the rate for purchases from QFs. These factors are commonly addressed in a PPA contract, and by denying QFs the ability to enter into a PPA contract the utilities will be unable to consider these factors and the Commission will be denied its opportunity to review and approve PPA contracts since there will be no such contracts for some QFs.

Q. HAVE YOU REVIEWED THE COMPANIES' PROPOSAL TO EXPAND ITS LIABILITY EXEMPTIONS?

A. Yes. "[T]he Companies propose to uniformly limit their liability to where the serving Company's gross negligence or willful misconduct is the sole and proximate cause of injury or damage," as discussed by Company Witness Hornung,[69] which would be a significant reduction in liability exposure from the current standard of negligence. Witness Hornung continues, explaining that "The broader exemption from liability for service interruptions is reasonable and necessary to protect the Companies and their customers from potentially ruinous liability."[70]

Q. HAVE THE COMPANIES ADEQUATELY JUSTIFIED THEIR PROPOSAL TO EXPAND LIABILITY EXEMPTIONS?

A. No. The Companies claim that a broader exemption from liability for service interruptions is necessary to protect the Companies and their customers from potentially ruinous liability.[71] I agree that a broader exemption from liability would be beneficial for the Companies and the shareholders of their parent corporation, but not necessarily the other half of that justification. It is, after all the Companies' customers who would suffer

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[69] Hornung Direct at 22: 17-19.
[70] Hornung Direct at 22: 22 – 23:1-2.
[71] Hornung Direct at 22: 22 – 23:1-2.

the consequences of the Companies' negligence that resulted in service interruptions or injury or damage to persons and property – potentially ruinous consequences and potentially a significant number of customers in the case of wildfires or events that negatively impact water quality.

Witness Hornung also suggests that "any expansion of the Companies' potential liability will result in increased costs for all customers in the form of necessarily higher liability insurance premiums and other risk mitigation measures the Companies would have to implement."[72] However, neither the Companies nor any party I'm aware of is proposing to expand the Companies' potential liability, and the possible impacts of expanding the Companies' liability exposure do not directly speak to any potential customer benefits or customer harms from the Companies' proposal to reduce their liability exposure.

Q. PLEASE SUMMARIZE YOUR EVALUATION OF THE COMPANIES' PROPOSED QF TARIFFS.

A. The Companies' proposed QF Tariffs unreasonably discriminate against QF that exercise their choice to supply a portion of their own power requirements by preventing BTM QFs from entering into a PPA contract, eliminating BTM QFs' choice of the purchase rate options provided under 807 KAR 5:054, undermining BTM QFs' ability to obtain financing, and by imposing a lower purchase price for BTM QFs' output through the arbitrary exclusion of payment for the capacity portion of the avoided cost rate. Additionally, the proposed QF Tariffs create an unreasonable and unnecessary shift in the balance of risk away from the utility and onto ratepayers and developers and are far outside the bounds of common and routine utility practices as to be shocking. Finally, the

[72] Hornung Direct at 23: 3-5.

proposed QF Tariffs ignore a wide variety of the policy requirements and utility obligations under 807 KAR 5:054, ignore the choices provided to QFs under 807 KAR 5:054, and would require the Commission to abrogate its review and approval authority specified under 807 KAR 5:054.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANIES' PROPOSED QF TARIFFS.

A. My recommendations are as follows:

- The denial of capacity compensation for BTM QFs should be rejected.
- Excluding BTM QFs from eligibility to enter into a PPA should be rejected.
- All QFs, including BTM QFs, should be required to enter into a PPA that established the terms under which they sell power to the Companies and that the PPA should be effective for a number of years sufficient to provide QF's certainty regarding contractual terms necessary for business planning and financing.
- The proposed expansion of liability protections for the Companies should be rejected.

III. NMS-2 TARIFF PROPOSAL

C. Evaluation of the Companies' Proposals

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANIES' NMS-2 TARIFF PROPOSAL.

A. The Companies proposed to provide NMS-2 bill credits based on the energy component of the QF rates for fixed-tilt solar,[73] to close NMS-2 to new participants when the net metering generation capacity reaches 1% of single-hour peak load,[74] and to provide compensation to new customer-generators who would have previously qualified for Rider

[73] Hornung Direct at 18: 10-12 and Exhibit CRS-6 at 11-12.
[74] Hornung Direct at 19: 4-11.

NMS-2 under the terms of Rider SQF.[75] The Companies' proposed NMS-2 bill credits do not include any compensation for generating capacity, carbon, ancillary services, environmental compliance, distribution capacity, transmission capacity, or jobs benefits as shown in the table[76] below excerpted from Witness Hornung's direct testimony.

Avoided Cost Type	KU ($/kWh)	LG&E ($/kWh)
Energy	0.03859	0.03786
Generation Capacity	-0-	-0-
Carbon	-0-	-0-
Ancillary Services	-0-	-0-
Environmental Compliance	-0-	-0-
Distribution Capacity	-0-	-0-
Transmission Capacity	-0-	-0-
Jobs Benefits	-0-	-0-
Total	**0.03859**	**0.03786**

Q. IS THE COMPANIES' NMS-2 TARIFF PROPOSAL REASONABLE?

A. No. The Companies' proposed NMS-2 bill credits do not fully compensate customer-generators for the value provided by exports delivered to the Companies, including value the Companies' own analyses indicate exist. The Companies' justification is inadequate to support the proposed changes to NMS-2 and relies largely on arguments the Commission has previously rejected. Additionally, the Companies' proposal is contrary to prior instructions provided by the Commission.

Q. PLEASE BRIEFLY EXPLAIN NET METERING.

A. Net metering was added to the "states-must-consider" federal standards list by the Energy Policy Act of 2005 and codified at 16 U.S.C. §2621(d)(11). Net metering or other

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[75] Hornung Direct at 20: 3-5.
[76] Hornung Direct at 18.

distributed generation compensation rules exist in nearly every state and U.S. territory.[77] As originally contemplated, net metering allows the power a customer-generator exports to the grid at one time to offset power imported from the grid at a different time. Prior to the widespread use of digital electric meters, a mechanical electric meter spun in one direction when power was imported and spun the other direction when power was exported, which resulted in a 1-to-1 offset ratio with 1 kWh exported to the utility by the customer-generator directly offsetting 1 kWh imported from the utility.[78]

Digital electric meters often have the capability to measure power imports and exports separately and enable cost-effective capture of time-differentiated bi-directional power flows. The capabilities of digital meters enable more nuanced approaches to compensating net metering customer-generators for power exports than a basic 1-to-1 kWh offset ratio. True net metering offsets imported power with exported power at a 1-to-1 ratio, and modified net metering, sometimes referred to as net billing, compensates customer-generators for power exports at a rate below the full retail rate.

Q. DO YOU CONSIDER THE COMPANIES' PROPOSED NMS-2 CHANGES TO BE NET METERING?

A. No. The Companies' proposal eliminates net metering in all but name. The current NMS-2 bill credit for Kentucky Utilities ("KU") is $0.07534/kWh and the proposed NMS-2 bill credit is $0.03859/kWh.[79] The current NMS-2 bill credit for Louisville Gas and Electric

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[77] Database of State Incentives for Renewable Energy. N.C. Clean Energy Technology Center. April 2025. Accessed on August 21, 2025. https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2025/04/DSIRE_Net_Metering_April2025.pdf

[78] Net Metering: In Brief. Congressional Research Service. November 14, 2019. Report No. R46010. at 2. https://www.congress.gov/crs_external_products/R/PDF/R46010/R46010.2.pdf .

[79] Case No. 2025-00113 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 115 of 216.

("LGE") is \$0.07089/kWh and the proposed NMS-2 bill credit is \$0.03786/kWh.[80] The Companies' proposal would reduce compensation for customer-generator exports under Rider NMS-2 by 48.8% for KU and by 46.6% for LGE. A large percentage change in rates of the magnitude proposed by the Companies should be supported with high-quality well-documented evidence that provides a thorough justification for the proposed change in rates; however, the Companies provide no such evidence or justification, as I discuss in later sections.

The Companies proposed to compensate exports under Rider NMS-2 at the rate they propose to compensate QFs for energy and ignore or dismiss all other components of compensation the Commission has previously directed be included.

Q. DO YOU HAVE OTHER CONCERNS RELATED TO THE COMPANIES' PROPOSED CHANGES TO RIDER NMS-2 IN ADDITION TO THE PROPOSED CHANGES TO THE EXPORT COMPENSATION RATE?

A. Yes, in addition to the proposed changes to export compensation rates discussed below and the previously discussed proposed expanded liability protections, the Companies' indicated that they expect to close Rider NMS-2 to new customers in LG&E territory in 2025 and in KU territory likely in 2027.[81] This expected closure of Rider NMS-2 is based on the forecast that "each of LG&E's and KU's cumulative generating capacity of net metering systems will reach 1% of its single-hour peak load during calendar year 2025 and 2026, respectively."[82]

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[80] Case No. 2025-00114 Attachment to Filing Requirement Tab 5 - 807 KAR 5:001 Section 16(1)(b)(4) Page 113 of 215.
[81] Schram Direct at 9: footnote 7.
[82] Schram Direct at 9: 13-15.

KRS 278.466(1) sets the "one percent (1%) of a supplier's single hour peak load during a calendar year" threshold after which the Companies would no longer be obligated to offer net metering service to new customer-generators. Again, while I am not an attorney offering a legal opinion, in terms of the policy, the statute does not prohibit the Companies from continuing to offer net metering service to new customers.

My policy concern is the manner in which the Companies are determining the 1% threshold and the lack of consistency between the Companies' different analyses. As Witness Schram described in response to an information request, "The net metering forecast uses installed DC capacity to calculate the 1% threshold."[83]

The Companies used the National Renewable Energy Laboratory's PV Watts in their distribution and transmission study provided as Exhibit PWW-3,[84] so I will reference the same PV Watts program. The DC capacity of a PV system is a power rating of the photovoltaic panels themselves based on standard test conditions – the miles-per-gallon ("MPG") rating for a new car model would be similar-type rating in that it is based on standard test conditions – but the DC power rating is not the same as the "generating capacity" of a solar system.

PV systems generating capacity, or the useful electric output of a PV system, is always less than the DC power rating of the PV panels due to system losses, DC-to-AC conversion efficiency of the inverter, and can even be affected by weather conditions such as cloud cover or temperature – all of which are inputs into PV Watts.[85] The PV

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[83] Companies' Response to KYSEIA Supplemental Request for Information, at Q-10(a).
[84] Waldrab Direct, Exhibit PWW-3 at 2, footnote 1.
[85] Dobos, Aron. PVWatts Version 5 Manual. National Renewable Energy Laboratory. NREL/TP-6A20-62641. September 2014. Available at https://docs.nrel.gov/docs/fy14osti/62641.pdf.

Watts results used by the Companies in Exhibit PWW-3[86] include the PV Watts program's default adjustments to the DC power rating 14.08% system losses, 96% inverter efficiency, and a DC-to-AC size ratio of 1.2 to determine a modeled PV system's useful electric output, or generating capacity.

A PV system's generation of AC power is always constrained by its inverter capacity. For instance, for a 10 kW-DC system, applying the default PV Watts DC-to-AC size ratio of 1.2, results in a generating capacity of 8.3 kW-AC.[87] In other words, at full output a PV system with a 10 kW DC power rating and a DC-to-AC size ratio of 1.2 is only able to contribute 8.333 kW of AC power to the grid.

It is also worth noting that in the Companies' study titled "Effects of Distributed Generation on Distribution & Transmission," the Companies used a clipped PV generation profile, basically assuming an even smaller inverter relative to a PV system's DC power rating, as shown in Figure 2 of Exhibit PWW-3.[88] I will discuss this more in depth in later portions of my testimony, but for the purposes of this part will simply point out the inconsistency of assumptions and methods in the Companies' analyses.

Using a "clipped profile" in Exhibit PWW-3 has the effect of reducing the peak output of the PV system in an analysis of PV's contribution to transmission and distribution capacity value that is based on peak capacity, and thereby potentially reducing PV's contribution to the peak and reducing its apparent value which supports

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[86] Attachments to Companies' Response to KY SEIA Supplemental Request for Information, at Q-7.
[87] 10 / 1.2 = 8.333
[88] Waldrab Direct, Exhibit PWW-3 at 2. Also, Companies' Response to KYSEIA Supplemental Request for Information, at Q-9, and Companies' Response to KYSEIA Initial Request for Information, at Q-12(c).

the Companies' efforts to reduce the export compensation rate under Rider NMS-2. However, when evaluating the 1% generating capacity threshold for purposes of closing Rider NMS-2 to new customer-generators, the Companies adopt assumptions of the opposite extreme by disregarding system losses, inverter inefficiencies, and DC-to-AC size ratios to overstate the generating capacity of installed net metering PV systems.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE DETERMINATION OF THE 1% THRESHOLD FOR CLOSING RIDER NMS-2 TO NEW CUSTOMER-GENERATORS.

A. I recommend applying the PV Watts default DC-to-AC size ratio of 1.2 to the DC power rating of net metered PV systems for purposes of calculating the 1% threshold.

I also recommend that the Companies be strongly encouraged by the Commission to justify their proposal to close Rider NMS-2 to new customer-generators when the 1% threshold is reached. Although the Companies will not be statutorily obligated to continue offering net metering to new customer-generators by KRS 278.466(1) after the 1% threshold is reached, Rider NMS-2 is still a regulated retail rate and a proposal to close a retail rate to new customers should be supported with adequate justification by the Companies and evaluated for reasonableness by the Commission, particularly in view of the Companies' representations concerning anticipated growth in peak load. The Companies have not provided reliable or reasonable justification for closing Rider NMS-2 to new customer-generators in this proceeding other than the forecast projection that the 1% threshold will be reached.

Q. Do you have additional recommendations with regard to the closure of Rider NMS-2 to new customers?

A. Yes. I recommend that the avoided cost components for transmission capacity, distribution capacity, and ancillary services be included in Rider SQF to be effective with the rates approved in this proceeding. The Companies have indicated their intent to direct customers who would no longer be eligible for Rider NMS-2 to the SQF tariff[89] and it would be reasonable for that small-system focused tariff to include the additional capacity components of the Rider NMS-2 compensation at this time.

Q. Please briefly summarize the Companies' proposals regarding avoided ancillary services cost.

A. The Companies proposed that the "appropriate value for the avoided ancillary services cost component of the Rider NMS-2 compensation rate is zero."[90] As in their last rate cases, the Companies' Open Access Transmission Tariff ("OATT") includes seven ancillary services with individually tariffed rates. As described by Witness Schram, "costs related to Schedule 3: Regulation and Frequency Response, Schedule 5: Spinning Reserve Service, and Schedule 6: Operating Reserve Service could be avoided if generation capacity costs are deemed to be avoidable."[91] As discussed previously in my testimony, avoided generation capacity costs are, in fact, avoidable, by DG resources. The amount and extent of the avoidable ancillary services costs would be increased substantially for net metering or DG systems coupled or co-located with battery storage, but the Companies' proposal is silent on customer-located battery systems.

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[89] Hornung Direct at 20: 3-5.
[90] Schram Direct at 36: 18-19.
[91] Schram Direct at 38: 1-4.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANIES' PROPOSALS REGARDING AVOIDED DISTRIBUTION CAPACITY COST.

A. As in their last rate cases,[92] the Companies propose a $0 compensation rate for avoided distribution capacity costs under Rider NMS-2.[93] The Companies also propose a conceptual framework for determining avoided distribution capacity cost arising from net metering that is nearly identical to the framework proposed in their 2020 rate cases but with an important adjustment specific to Rider NMS-2 customer-generators.[94] The Companies attempt to justify their proposed compensation rate for avoided distribution capacity costs using a study presented as Exhibit PWW-3.

Q. PLEASE DESCRIBE THE COMPANIES' PROPOSED FRAMEWORK REGARDING RIDER NMS-2 CUSTOMER-GENERATORS.

A. The Companies attempt to differentiate customer-generators served under Rider NMS-2 from those served under Rider NMS-1 based on the date Rider NMS-2 began[95] by restricting consideration of avoided distribution capacity costs to only investments made after the date Rider NMS-2 began.[96] Witness Waldrab states, "By definition, Rider NMS-2 customers cannot have avoided any embedded distribution cost prior to September 24, 2021; net metering customers taking service prior to that date take service under Rider NMS-1."[97]

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[92] Case Nos. 2020-00349 and 2020-00350.
[93] Waldrab Direct at 40: 21-22, 41: 1-2.
[94] *Id.* at 37: 7-17.
[95] September 24, 2021
[96] Waldrab Direct at 38: 1-6.
[97] *Id*. at 38: 4-6.

I find this aspect of the proposed framework particularly perplexing. As I understand it, the term "embedded costs" refers to historical costs or those associated with investments that have already been made, as in an embedded cost of service study used in traditional utility ratemaking. Because the investments have already been made and the costs already incurred, embedded costs are not avoidable per se. However, it is possible for distributed generation ("DG") systems to reduce the burden on existing infrastructure posed by load growth and delay or prevent maintenance, replacement, or upgrade expenses, as well as reduce the cost of new distribution infrastructure or distribution system expansions.

This aspect of the framework described by Witness Waldrab, appears to indicate that the Companies intend to exclude all costs associated with distribution infrastructure installed prior to the date Rider NMS-2 service began. Such an approach would not make sense, since a Rider NMS-2 customer-generator could well be served by distribution infrastructure installed decades ago and such an NMS-2 customer would contribute to delaying or preventing maintenance costs as well as potentially contribute to delaying, reducing, or completely avoiding upgrades necessary to serve load growth – the contribution to avoided these costs associated with older infrastructure could well be higher than the contribution to new infrastructure that was designed with higher electric loads in mind.

The distinction proposed by Witness Waldrab seems to serve no purpose, unnecessarily complicates and confuses the evaluation of avoided distribution capacity costs, and could potentially be interpreted as excluding benefits and cost savings Rider NMS-2 customer-generators provide to older portions of the Companies' distribution system from being included in the determination of avoided distribution capacity costs. Rider NMS-2 customer-generators should receive compensation for their contribution to all avoided distribution costs throughout the Companies' distribution system.

Q. WHAT ARE YOUR GENERAL THOUGHTS ON THE STUDY PRESENTED AS EXHIBIT PWW-3?

A. The Companies rely upon the analysis in Exhibit PWW-3 to support their claim that "the appropriate avoided distribution capacity cost component for Rider NMS-2 is zero because Rider NMS-2 have allowed the Companies to avoid and are not projected to allow the Companies to avoid any distribution capacity costs."[98] Witness Waldrab continues by confirming that DG resources like Rider NMS-2 generation can avoid distribution capacity costs, but suggests in the offered example of the Companies' affiliate, PPL Electric Utilities, that "avoidance of distribution capacity cost" requires 1) a significant penetration of DG resources, and 2) utility "control and dispatch" of resource functions.[99]

The Commission previously addressed the first of these requirements in the Companies' last rate case, stating "The Commission agrees with KYSEIA's criticism that LG&E/KU's argument that avoided distribution should not be compensated until there is a critical mass to avoided additional distribution is a self-fulfilling prophecy. Without an appropriate price signal, that critical mass will likely not be achieved. Each net metering customer provides a small incremental reduction to load and should be appropriately compensated" (footnote omitted). Somewhat ironically, the Companies found small net

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[98] Waldrab Direct at 40: 21-22 and 41: 1-2.
[99] *Id.* at 41: 5-9.

effects of solar generation on system peak, but rounded the benefits to zero, stating "the MW savings would be rounded to 0 MW for planning purposes."[100]

The second requirement for the avoidance of distribution capacity cost offered by Witness Waldrab is utility dispatch and control of DG resource functions, for which he indirectly referenced Rhode Island Energy, another PPL utility. In addition to other programs, Rhode Island Energy has smart thermostats, electric vehicle demand response, and battery initiatives as part of its ConnectedSolutions program offerings.[101] All of these programs offer opportunities to enhance the value to avoided costs components such as energy, generating capacity, ancillary services, distribution capacity, transmission capacity, carbon emissions, and even jobs benefits when coupled with an NMS-2 resource. Plus, they also offer stand-alone benefits for ratepayers even without an NMS-2 resource.

In summary, the Companies did find value from NMS-2 resources in a study with numerous flaws I will address shortly but chose to round it down to zero. The small magnitude of benefits the Companies found are due partly to study design, partly to interconnection rules for net metering that constrain geographic aggregation of participants, and due to the low rate of net metering adoption which is influenced by the low value of net metering exports and undifferentiated price signals. Effectively, the Companies are undermining available cost reductions and ratepayer benefits from multiple angles, which results in increased electric costs and threatens electric affordability for all ratepayers.

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[100] Waldrab Direct, Exhibit PWW-3 at 4.
[101] *See* https://www.rienergy.com/site/ways-to-save/save-money-with-rebates-and-incentives/connectedsolutions

Q. PLEASE DESCRIBE SOME OF THE FLAWS YOU IDENTIFIED IN THE STUDY PRESENTED AS EXHIBIT PWW-3?

A. There are numerous flaws I identified in the study, including:

- Use of a "clipped production profile" that artificially and incorrectly reduces peak PV output;
- The small sample size undermines the validity of the study's results;
- The lack of complete meter data and changing study participants over the study period raises concerns about whether the direct results of the study data could even be taken at face value, much less extrapolated into anything resembling meaningful broader conclusions;
- The study's exclusive focus on new construction failed to include or consider potential benefits on the existing distribution system;
- One of the study's two years is 2020 during which normal behavior patterns, especially at residences, were significantly disrupted by the COVID pandemic; and
- The study's focus on a single circuit peak does not capture or represent the peak load conditions on all the Companies' circuits.

Distribution capacity cost is related to NMS-2 exports during distribution system peaks, yet as shown in Figure 2 of PWW-3,[102] the Companies elected to use a clipped solar production profile that artificially cut off peak solar output, potentially reducing solar's contribution to distribution system peak. The reason provided for the use of a "clipped" solar production profile was "In exhibit PWW-3, a clipped production profile was chosen to maximize the capacity factor for the solar production resulting in the best-

[102] Waldrab Direct, Exhibit PWW-3 at 2.

case output for solar."[103] In other words, the Companies deliberately chose a "clipped" solar production profile by assuming an undersized inverter relative to the PV system DC power rating[104] to maximize the capacity factor of the system when conducting this analysis whose results are dependent on a coincident peak. In simpler terms, the Companies chopped the peak off of solar output in analysis whose results are based on peak contribution.

The Companies reported using data from 47 meters out of 2,728 residential meters on circuit WO1184 for LG&E, and they reported using data from 21 meters out of 1,254 residential meters on circuit 777-0431 for KU; additionally the customer load shapes based on the original study using 2019 and 2020 data were left unchanged from the original study in the 2025 update.[105] The Companies explained that the original study only had access to data from early-adopters who opted in to AMI[106] which 1) raises questions about how similar the participants are to the general residential population served by these circuits and 2) unfortunately does not overcome the lack of statistical validity of the study. Sample size determines the number of subjects needed in a study, and larger sample sizes reduce the statistical margin of error.[107] Using the Qualtrics sample size calculator set for a 95% confidence interval and a +/-5% margin of error, the ideal sample size for LG&E's 2,728 residential meters is 337 – more than 7 times the sample size used by the Companies. For KU's 1,254 residential meters, the ideal sample size is 295 – more than 14 times the sample size used by the Companies. For context, the

[103] Companies' Response to KYSEIA Initial Request for Information at Q-12(c).
[104] *See* Companies' Response to KYSEIA Supplemental Request for Information at Q-9.
[105] Companies' Response to KYSEIA Supplemental Request for Information at Q-6.
[106] *Id*.
[107] *See* https://www.qualtrics.com/blog/calculating-sample-size/

parameters of the Qualtrics sample size calculator for its least reliable sample size stop at a 90% confidence interval and +/-10% margin of error, which would be an ideal sample size of 66 for LG&E and 65 for KU.

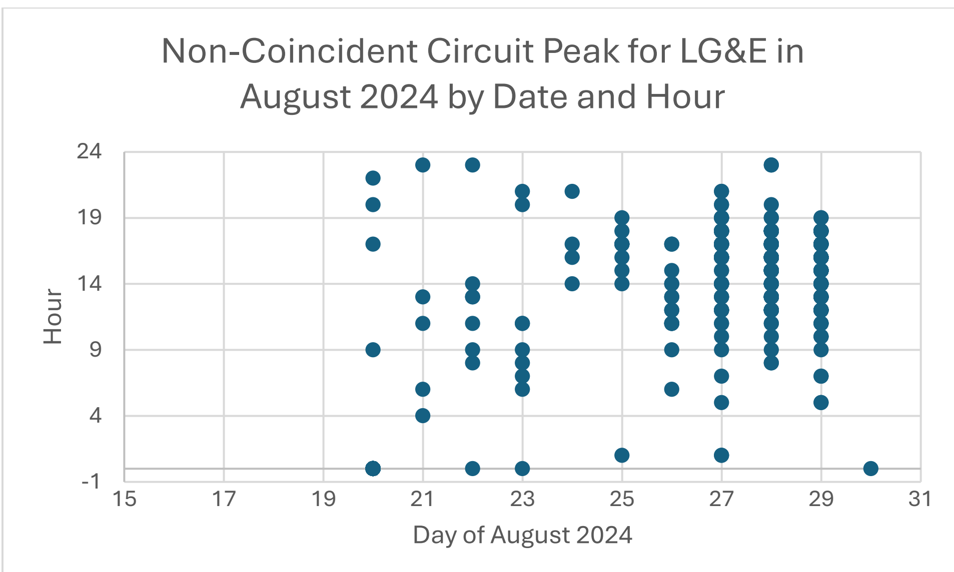
Worse, the meter data from these samples is incomplete. LG&E's sample is missing data for 16% of the 15-minute intervals used in the study and KU's sample is missing data for 24.37% of the 15-minute intervals used in the study.[108] Over the two-year study period, the composition of the study sample changed and generally grew to the ultimately small number of residential meter samples mentioned above. Given the percentage of missing values in the sample data and how the number of meters sampled increased over time, it is not clear that the sample average results are even representative of the sample itself, especially since the most complete meter data is from 2020 when behaviors were significantly altered due to the COVID pandemic, generally resulting in much more activity in residences that would typically be conducted elsewhere.

The study in Exhibit PWW-3 relies on utility-specific peak load on a single circuit, but in no way accounts for or is representative of the unique characteristics of the Companies' many distribution circuits. In response to an information request, the Companies provided the date and time of the "quantity of maximum annual non-coincident peak demand for each individual substation and distribution feeder on the Companies' systems for each of calendar years 2023 and 2024."[109,110] Although there is

[108] Attachment to Companies' Response to KYSEIA Initial Request for Information at Q-10, worksheets LGE_Raw_Meter_Data and KU_Raw_Meter_Data. Missing interval data are identified by the #NUM! error value.
[109] Attachments to Companies' Response to KYSEIA Supplemental Request for Information at Q-5(a).
[110] The Attachment appears to only include data for LG&E.

some uncertainty regarding the provided data, it appears to be non-coincident peak levels by substation and circuit for 2024 for LG&E. Figure 1 below displays the data and hour for circuit-specific peaks, all of which were in August 2024 based on the provided data file. As demonstrated in Figure 1, individual circuits peak on different days and at different times of the day, including some weekends.[111] A distribution capacity study should account for these variations among circuits and similar variations among transformers and substations rather than, as in the Companies' study, attempt to extrapolate values based on an overly small sample with incomplete data from one circuit in a utility's territory.

Figure 1



[111] August 24, 2024, was a Saturday.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANIES' PROPOSALS REGARDING AVOIDED TRANSMISSION CAPACITY COST.

A. The Companies proposed that the "appropriate avoided transmission capacity cost component for Rider NMS-2 is zero."[112] The Companies justify this proposal based on an analysis that is "[c]onsistent with the analytical framework stated in the testimony of Peter W. Waldrab"[113] and because "the Companies have not identified any transmission capacity projects that Rider NMS-2 customers will allow the Companies to avoid over the next ten years."[114]

As described in Exhibit BJM-3, the Companies compared two models, one with net metering generation and one without, and the model with net metering generation "had no significant impact on the avoidance of transmission system upgrade projects. Therefore, the overall estimated savings due to the NM DER generation was determined to be $0."[115] The first obvious gap in the analysis is that "[w]inter peak models were not analyzed due to the expectation that DER generation output would be 0% during this time."[116] As I have mention at various places throughout my testimony, DG resources are routinely and increasingly coupled with battery systems, and as in those examples, the Companies have assumed away commercially available increasingly common technology such as batteries co-located or coupled with DG systems, excluded them from their analysis, and reach incomplete conclusions. Additionally, wind has a winter capacity

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[112] McFarland Direct at 31: 17-18.
[113] *Id*. at 16-17.
[114] *Id*. at 31: 19 – 32:1.
[115] McFarland Direct, Exhibit BJM-3 at 3.
[116] *Id*. at 4.

value according to Witness Schram, as previously discussed in the portion of my testimony addressing avoided generating capacity cost.

Second, the avoided transmission capacity cost results under the P3 simulation indicate the potential for net metering to contribute to avoiding an MVA flow violation and a voltage violation.[117] At the very least, even with a pared-down study whose scope excluded obvious and increasingly common DG system configurations, the study identified that net metering contributes to a reduction in risk on the Companies' transmission system. Risk has value, otherwise the Commission should approve a return on equity equal to or less than the Companies' cost of debt.

Third, the avoided transmission cost study limits its scope to avoiding a transmission investment, and similar to the avoided capacity cost analysis suggests that because net metering market penetration is so low that net metering alone can't avoid a transmission investment. The study in Exhibit BJM-3 is silent on the potential for net metering to make a contribution to avoiding or delaying a transmission investment in conjunction with other programs such as energy efficiency, demand response, etc. – a contribution which surely would have value.

Fourth, the study in Exhibit BJM-3 exclusively considers the avoidance of new transmission investments and completely overlooks the opportunity cost associated with transmission capacity. The contribution of net metering or DG systems to making additional transmission capacity available to the Companies dismisses the value of existing transmission capacity that can be marketed by the Companies.

[117] *Id*. at 6.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANIES' PROPOSALS REGARDING AVOIDED CARBON COST.

A. The Companies proposed that "[t]he appropriate value for the avoided carbon cost component of the Rider NMS-2 compensation rate is zero" and claimed that there is "currently no carbon price for the Companies' carbon emissions—and the recently finalized federal greenhouse gas regulations applicable to the Companies' operations would not create a carbon price" as justification.[118] Appendix A of Exhibit CRS-6[119] shows planned new natural gas-fired generation units which will be subject to the recently finalized federal greenhouse gas regulations, and those regulations impose restrictions on the capacity factor of natural gas-fired generation units that are not equipped with carbon capture and storage technology. The federal regulations would create avoidable costs if the Companies elected to limit the capacity factor of new gas-fired generation, especially combined cycle units, because limiting the capacity factor of a baseload-type generating unit would reduce its energy output and the Companies' recovery of the unit's fixed costs would then be spread over a smaller number of kWh, increasing the total cost per kWh generated. Such costs could be reduced by accelerated deployment of DG resources that enabled downsizing of a new natural gas-fired generating unit and compensation for DG resources co-located with batteries would support further reductions in new natural gas capacity.

If the Companies opted instead to install carbon capture and storage ("CCS") technology, and not have capacity factor limitations imposed, the reduction in costs is

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[118] Schramm Direct at 38: 12-15.
[119] Schram Direct, Exhibit CRS-6 at 13-14.

similar. CCS technology creates an additional auxiliary load and reduces the net output of a generating unit, plus the CCS pipeline infrastructure will add additional load to the system, and the combination of increased system load plus decreased net output could very easily require upsizing the new gas generating units. However, with increased DG, especially coupled with battery storage, the upsizing of the generator unit could be avoided, thereby generating cost savings.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANIES' PROPOSALS REGARDING AVOIDED JOBS BENEFITS.

A. Much as they did in their last rate case, the Companies provided no meaningful analysis of the NMS-2 rate component related to job benefits and simply claimed "such benefits are outside the Commission's jurisdiction."[120] The Commission directed "LG&E/KU to evaluate job benefits and economic development as an export rate component for LG&E/KU's next rate case filing" in its Order[121] in the Companies' last rate case. The Companies provided no explanation for their failure to fulfill this requirement and while the Companies' assertion that job benefits are outside the Commission's jurisdiction could be used to support the Companies' proposal to not include job benefits as an NMS-2 rate component, the Companies clearly failed to conduct the evaluation required by the Commission.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NMS-2 TARIFF RATES?

A. I recommend the Commission retain the existing methodology and compensate customer-generators based on re-calculated current values as discussed throughout my testimony. I

[120] Hornung Direct at 18: 14.
[121] Case Nos. 2020-00349 and 2020-00350, Order dated September 24, 2021.

also recommend that the 1% NEM cap be calculated based on the AC generating capacity rather than on the DC power rating and that the Companies should be directed to provide justification for the reasonableness of their proposal to close Rider NMS-2 to new customers.

IV. CO-LOCATED RESIDENTIAL BATTERY ENERGY STORAGE SYSTEMS

Q. PLEASE ELABORATE ON THE SMALL-SCALE BATTERY SYSTEMS MENTIONED THROUGHOUT YOUR TESTIMONY.

A. Small-scale battery systems suitable for residential or small commercial installations are increasingly common and commercially available. According to the U.S. Energy Information Administration ("EIA"), there was over 2.3 GW of small-scale battery system capacity installed in the U.S. as of the end of 2023.[122] Of that about 920 MW, or 39.9%, were residential sector installations and 72.4%, or 666 MW, of residential battery installations were located in states other than California.[123] The residential energy storage market is widespread and diverse with 10 states reported by the EIA as having more than 15 MW of residential storage capacity installed as of the end of 2023.[124]

Residential energy storage is also a rapidly growing market, with installed residential storage capacity more than doubled from just under 1.1 GW at the end of 2021

[122] EIA. Battery Storage in the United States: An Update on Market Trends. April 25, 2025. https://www.eia.gov/analysis/studies/electricity/batterystorage/xls/2024%20Battery%20Storage%20Figures.xlsx at Figure 13.
[123] *Id*.
[124] *Id*. at Figure 14.

to over 2.3 GW by the end of 2023.[125] McKinsey & Co. project the market for residential energy storage capacity will grow at a compound annual growth rate of 14% through 2030.[126] Residential battery storage is also increasingly cost effective, as discussed in a recent journal article published in Nature Energy which found that "60% of US households can reduce their electricity costs by a mean of 15%, and 63% can achieve affordable backup power covering 51% of essential energy needs during outages on average, through solar–battery systems."[127]

Small-scale battery systems coupled with DG can turn every rooftop participating in net metering into a dispatchable capacity resource at any time of the day on any day of the year – if provided an appropriate price signal by reasonable rate design. Additionally, batteries coupled with DG also promote disaster resilience and self-reliance in all the communities where they are located. Even a single net metering household, particularly if the DG system is coupled with batteries, in a community can provide electricity to charge communications devices or to power critical medical devices, provide potable water, or refrigeration to keep vital daily medications like insulin viable during an extended power outage resulting from a major disaster such as Hurricane Helene, which "Louisville Gas

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[125] EIA. Battery Storage in the United States: An Update on Market Trends. https://www.eia.gov/analysis/studies/electricity/batterystorage/xls/battery_storage_2022.xlsx at Figure 13.

[126] McKinsey & Co. Enabling renewable energy with battery energy storage systems. August 2, 2023. https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/enabling-renewable-energy-with-battery-energy-storage-systems#/

[127] Sun, T., Feng, Y., Zanocco, C. *et al.* Solar and batteries are affordable options for US households. *Nat Energy* **10**, 928–929 (2025). https://doi.org/10.1038/s41560-025-01822-9

& Electric and Kentucky Utilities described Helene as the fourth-largest weather event to impact their customers over the past 20 years."[128]

Q. DO YOU HAVE ADDITIONAL RECOMMENDATIONS REGARDING BATTERY STORAGE SYSTEMS?

A. Yes. The Companies repeatedly point to their growing winter capacity needs and how the sun doesn't shine at night, but when coupled with a battery, solar power is available 24 hours a day, even at night. I recommend the Companies include battery-coupled DG resources into their Rider NMS-2 and QF Tariffs, with appropriate price signals, and I also recommend the Commission consider the resilience benefits offered by these systems to all ratepayers in its evaluation of a just and reasonable compensation rate for net metering exports.

V. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the following:

- The energy credit be increased to include variable minor maintenance costs based on PJM's most recent default minor maintenance cost values using the method in the example I provided;
- The Companies should clarify the circumstances under which they propose a solar or wind QF or Rider NMS-2 customer-generator with a co-located or coupled battery energy

[128] Angel, Brenna. Cleanup and repairs continue in wake of Hurricane Helene. Kentucky Association of Counties. October 2, 2024. https://kaco.org/articles/cleanup-and-repairs-continue-in-wake-of-hurricane-helene/

storage system would be compensated based on the "Other" QF technology type and that the proposed QF tariffs and Rider NMS-2 rates be adjusted accordingly;

- The BESS-based capacity credit methodology for determining the $/MWh price paid to QFs should be corrected so that the capacity credit value would be sufficient to allow the Companies to recover the full costs of the resource if the Companies were compensated in the same manner as QFs or Rider NMS-2 customers;
- The pricing structure for capacity compensation be adjusted to reflect seasonality and timing of peak loads and provide a price signal sufficient to influence market participants' contribution to peak demand;
- All QFs and Rider NMS-2 customers receive a capacity credit because the Companies have demonstrated an immediate and ongoing capacity need which could be fully or partially met by all types of QFs – including solar during winter if paired with a battery;
- The denial of capacity compensation for BTM QFs be rejected;
- Excluding BTM QFs from eligibility to enter into a PPA be rejected;
- Required all QFs, including BTM QFs, to enter into a PPA with and agreement term length defined separately from the price term length and an agreement term length of sufficient duration to enable QFs to obtain financing and certainty regarding the conditions under which they sell power to the Companies;
- The proposed expansion of liability protections for the Companies be rejected;
- Apply the PV Watts default DC-to-AC size ratio of 1.2 to the DC power rating of net metered PV systems for purposes of calculating the 1% threshold;

- Include the avoided cost components for transmission capacity, distribution capacity, and ancillary services be included in Rider SQF, effective with the rates approved in this proceeding;
- Include compensation for avoided distribution costs that occur throughout the Companies' distribution system, including for those parts of the distribution system placed in service prior to the start of Rider NMS-2;
- The Companies conduct an updated and comprehensive marginal distribution capacity cost study that accounts for circuit- and infrastructure-level variations in non-coincident peaks and is based on a robust and statistically valid sample of customers;
- Retain the existing avoided cost components for Rider NMS-2 and compensate customer-generators based on re-calculated current values;
- Battery-coupled DG resources be included in the Companies' Rider NMS-2 and QF Tariffs, with appropriate price signals, and that the Commission consider the resilience benefits offered by these systems to all ratepayers in its evaluation of a just and reasonable compensation rate for net metering exports.

Q. DOES THAT CONCLUDE YOUR TESTIMONY.

A. Yes.

JASON W. HOYLE

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EDUCATION

Master of Business Administration, August 2003
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EXPERIENCE

Director of Research January 2025 - Present
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- Lead consulting engagements for clean and distributed energy sector clients, including writing reports, conducting research and analysis on state energy policy and market issues, supporting regulatory and legislative advocacy, and providing expert witness testimony.
- Manage EQ Research's services tracking U.S. electric utility rate cases, including reviewing and analyzing electric rate cases and managing subscriber-facing database.
- Research, track, and summarize state-, regional-, and national-level regulatory and legislative energy policy developments for EQ Research's policy tracking services.
- Coordinate EQ Research's regulatory and compliance consulting services for Community Choice Aggregation programs in California, including regulatory monitoring and analysis, compliance reviews, litigation support, and resource procurement planning.

Instructor August 2012 – December 2021
Department of Sustainable Technology and the Built Environment, Appalachian State University | Boone, North Carolina

- Developed undergraduate- and graduate-level course curriculum in the sustainable technology program focused on the policy, market, and economic context for the development of energy projects. Specific course topics included regulatory oversight roles, energy and related environmental attribute markets, power purchase agreements, tax-based and other incentives, and implications of emerging technologies and business models in power markets.

Senior Research Associate January 2020 – January 2021
Research Associate January 2010 – January 2020
Center for Economic Research & Policy Analysis, Appalachian State University | Boone, North Carolina

- Led development and implementation of research proposals on topics of electricity and emissions markets and regulation, ecosystem valuation, and economic development.
- Oversaw and supervised collection and analysis of energy and economic data for research projects, reports to legislative commissions and committees, and expert witness testimony.
- Managed development and implementation of process for obtaining customer consent and anonymization of electric utility customer data in partnership with electric utilities for energy-related behavioral economics experiments.

Research Analyst August 2005 – January 2020
Research Associate August 2003 – August 2005
Appalachian Energy Center, Appalachian State University | Boone, North Carolina

- Managed development and implementation of research and program initiatives on state- and national-level energy policy and regulations, including renewable energy incentives, retail rate design and analysis, wholesale electricity markets, greenhouse gas emission and carbon offset markets, sustainability accounting, and greenhouse gas inventories.
- Oversaw and led consultation services for clients from government, industry, academia, and non-profit sectors on energy- and greenhouse gas-related policies, including due diligence, legal and regulatory analysis, pro forma financial and valuation analysis, and negotiated PPA contracts and contracts for the sale of both carbon offsets and renewable energy certificates.
- Developed curriculum for and taught professional continuing education courses on renewable energy policy, finance, and regulation offering AIA Learning Units (LU), engineering Professional Development Hours (PDH), CPA (CPE) credits, Continuing Legal Education (CLE) credits, SWANA Continuing Education Units (CEU), and Continuing Forestry Education (CFE) credits.

SELECTED SERVICE & AFFILIATIONS

Scientific Peer Reviewer, Landfill Gas Destruction and Beneficial Use Projects v2.0, American Carbon Registry (2020-2021)

- Reviewed proposed methodology update to landfill gas project protocol (Landfill Gas Destruction and Beneficial Use Projects v2.0) for adherence to commonly accepted carbon offset principles.
- Provided comments and feedback to maximize practical usefulness and conformance with carbon accounting principles of proposed methodology update.

Workgroup Member, Landfill Project Protocol Version 5.0, Climate Action Reserve (2018-2019)

- Reviewed and advised Climate Action Reserve on proposed changes to U.S. Landfill Project Protocol Version 5.0.
- Provided information and guidance on economic, financial, and market factors used in establishing the protocol’s Performance Standard Analysis (i.e. basis for differentiating between common practice and eligible project activities).

Graduate Faculty, Department of Sustainable Technology and the Built Environment, Appalachian State University (2014 – Dec. 2021)

Graduate and Honors Thesis Committees, Department of Sustainable Technology and the Built Environment, Appalachian State University (2015 - 2019)

Advisory Council, International Hydrail Conference (since 2005)

- Coordinated with conference hosts (from North America, Europe, and Asia) on conference planning, logistics, and promotion.
- Reviewed proposed presentation and provided recommendations on conference agenda and proposal acceptance.
- Compiled data and information on worldwide development and deployment of hydrogen-based rail technology, and advised government, industry, and academia on technology, policy, and deployment topics related to hydrogen trains and the broader hydrogen economy.

Advisory Board, N.C. Farm Center for Innovation and Sustainability (2009-2014)

- Advised on program development and greenhouse gas offset project opportunities (specifically carbon offsets from forestry and biochar).
- Prepared market analysis of biochar products and carbon offsets from biochar.
- Conducted operations analysis of mobile biochar production technology with focus on labor cost function and maximizing equipment capacity utilization.

Advisory Board, Western N.C. Clean Energy Leadership Group (2009-2012)

Advisory Board, N.C. Green Business Fund (2007-2009)

- Advised on design and review of Request for Proposals for new state investment fund focused on supporting development of businesses engaged in sustainable technology.
- Evaluated proposals for funding and presented evaluation to grantmaking committee.
- Participated as member of the grantmaking committee to prioritize grant proposals and select proposals for funding.

EXPERT WITNESS ENGAGEMENTS

Testimony

Michigan - Case No. U-21297, DTE GRC

North Carolina - Docket E-34 Sub 54, New River Light & Power GRC

Michigan - Case No. U-21461, Indiana Michigan Power GRC

Virginia – Case No. PUR-2024-00161, Appalachian Power Co. Net Metering

SELECTED PUBLICATIONS & PRESENTATIONS

Books, Articles & Reports

"Measuring the Economic Impact of COVID-19-Related Business Interruptions on the Regional Economy" (with O. Ashton Morgan) *N.C. Policy Collaboratory*. Report. December 2020. Chapel Hill, N.C.

"Trash to Treasure: Predicting Landfill Gas Flow to Optimize Electricity Generation." (with Dan Emery, Edgar Hassler, Joseph Cazier) *JISAR*, *13*(3), 29. (2020)

"Optimizing sequestered carbon in forest offset programs: balancing accounting stringency and participation." (with Wise, L., Marland, E., Marland, G., Kowalczyk, T., Ruseva, T., Colby, J. & Kinlaw, T.) *Carbon balance and management*, *14*(1), 1-11. (2019)

"Trash to Treasure: Predicting Landfill Gas Flow to Optimize Electricity Generation" (with Dan Emery, Edgar Hassler, Joseph Cazier) *Conference on Information Systems Applied Research*. Conference Paper. Nov. 6-9, 2019. Cleveland, Ohio.

"Small-Scale Landfill Gas Offset Protocol" (with S. Steury and J. Dees) Appalachian State University. 2017.

Understanding and Analysis: The California Air Resources Board Forest Offset Protocol. (with Eric Marland, Grant Domke, Gregg Marland, Laurel Bates, Alex Helms, Benjamin Jones, Tamara Kowalczyk, Tatyana B Ruseva, Celina Szymanski) Springer Briefs in Environmental Science, 2017.

"Accounting for harvested wood products in a forest offset program: Lessons from California" (with L. Bates, B. Jones, E. Marland, G. Marland, T. Ruseva, and T. Kowalczyk) *Journal of Forest Economics* 27 (2017): 50-59.

"Additionality and permanence standards in California's Forest Offset Protocol: A review of project and program level implications" (with T. Ruseva, E. Marland, C. Szymanski, J. Hoyle, G. Marland, T. Kowalczyk) *Journal of Environmental Management* 198 (2017): 277-288.

“UNC Wilmington Greenhouse Gas Inventory and Sustainability Action Plan” (with D. Ponder, A. Toneys and J. Mosteller) report to UNC-Wilmington. August 2014.

“Summary of Avoided Cost Rates & N.C. Utility Commission Proceedings Update” report to Appalachian Institute for Renewable Energy, Doc. No. 12-0194_006. July 2013.

“Value from Solid Waste Management” report to Board of Commissioners, Rockingham County, NC. March 2013.

"Performance-based potential for residential energy efficiency" *CICERO Report*. January 2013.

“Behind-the-Meter Sale of Unbundled RECs” report to Appalachian Institute for Renewable Energy, Doc. No. 12-0194_002. May 2012.

“Energy Internships in North Carolina: An Evaluation of Experiences and Indicators for the Future” (with M. Hoepful and L. Murphy) report to State Energy Office, N.C. Department of Commerce. April 2012.

“Electricity Sales & Generating Facility Leases in North Carolina” report to Appalachian Institute for Renewable Energy, Doc. No. 12-0194_001. February 2012.

“Standard Purchase Offers for Power & Environmental Assets in North Carolina” Appalachian Energy Center Report. October 2011.

“Comments on Proposed Changes to the Climate Action Reserve Landfill Project Protocol” submitted to Climate Action Reserve. June 2011.

“Monetizing Green Assets & Incentives: Watauga County, NC” report to Board of Commissioners, Watauga County, NC. January 2011.

“Electricity Service Options at the Watauga County Landfill” report to Board of Commissioners, Watauga County, NC. August 2010.

“Retail Carbon Offset Survey 2009” (with J. Little, T. Cherry, H. Whalan and D. Six) report to Environmental Credit Corporation. May 2010.

“Expectations in an Uncertain Economy” (with T. Cherry and B. Toney) Center for Economic Research and Policy Analysis Research Report, March 2010.

"Landfill Gas Project Financial Analysis: Edgecombe County" report to Board of Commissioners, Edgecombe County, NC. March 2010.

"Landfill Gas Financial Analysis: Rutherford County" report to Board of Commissioners, Rutherford County, NC. March 2010.

Secondary Economic Impact Analysis of Greenhouse Gas Mitigation Options for North Carolina. (with D. Ponder and J. Tiller) report to North Carolina Climate Action Plan Advisory Group. Center for Climate Strategies. October 2008.

"Aspects of Energy Use and Capacity in North Carolina" (with D. Grady). *Popular Government*. Vol. 73, No. 3, pp. 5,6,10-11,22-23. 29-30. Spring Summer 2008.

Presentations

"Community engagement strategies for capturing co-benefits from offset projects" Achieving Corporate Climate Ambitions with Carbon Offsets, Climate Action Reserve Webinar. 8 November 2018.

"Accounting for negative CO2 emissions" (with Marland, E., Marland, G., Kowalczyk, T., Ruseva, T., and Wise, L.). International Conference on Negative CO2 Emissions, Gothenburg, Sweden 22-24 May, 2018.

"Negative Electricity Prices" RECONNECT 2017. Department of Mathematics, Appalachian State University, Boone, NC. June 2017.

"Third Party Ownership Structures and Net Metering Considerations" North Carolina State Energy Conference. NC State University, Raleigh, NC. 20-21 April 2016.

"Investigating the Economic Viability of a Solid Waste-To-Biofuel Facility in Western North Carolina" (with G. Rockwell, L. Preston, C. North, J. Ferrell, J. Ramsdell, A. Morgan and M. McKee) Invited Lecture and Poster Presentation, NC Department of Agriculture Bioenergy Field Day, Mills River, N.C. 27 August 2015.

"Renewable Energy & Energy Efficiency in Commercial Construction" Construction Professionals Network of North Carolina, Mid-Year Educational Conference. Greensboro Marriott Downtown Hotel, Greensboro, NC. 3 Oct. 2014. Invited Presentation. (offering CEU credits)

"Energy, Economy and Environmental Policy: Balancing Need and Constraint" UNC-Charlotte Lecture Series. University of North Carolina at Charlotte, Department of Civil Engineering, Charlotte, NC. 10 Sep. 2014. Invited lecture.

"Negative Marginal Cost Electricity: An opportunity for low-cost value-added hydrogen production" 8th International Hydrail Conference, Ryerson University, Toronto, Canada. June 2013.

"Watauga County, NC: 195 kW or Bust" 16th Annual Landfill Methane Outreach Program, U.S. Environmental Protection Agency. Baltimore, MD, USA. January 2013.

“Economic Valuation Methods for Public Investment in Hydrail” 7th International Hydrail Conference, University of Birmingham, Birmingham, U.K. July 2012.

“State Energy Internship Program Evaluation” (with M. Hoepful) 9th Annual Sustainable Energy Conference, State Energy Office, N.C. Department of Commerce. Raleigh, NC, USA. April 2012.

“Facilitating Statewide Community-Based LFG: 6 years, 14 counties, and 10 projects” 15th Annual Landfill Methane Outreach Program Conference, U.S. Environmental Protection Agency. Baltimore, MD, USA. January 2012.

“The Value of Hydrail” 6th International Hydrail Conference, Istanbul, Turkey. July 2010.

“Carbon Credit Purchasing in the Local Decision Context” 13th Annual Landfill Methane Outreach Program Conference, U.S. Environmental Protection Agency. Baltimore, MD, USA. January 2010.

“North Carolina Economic and Energy Outlook for Local Governance” (with T. Cherry) presentation to NCAPA Summer Planning Institute. May 2009.

“New Renewable Energy Markets for North Carolina Companies” 6th Annual North Carolina Sustainable Energy Conference, State Energy Office, N.C. Department of Commerce. Raleigh, NC, USA. April 2009.

“Competitive Insight into the Energy Economy: Charlotte Region” invited lecture at Central Piedmont Community College, Charlotte, NC. November 2008.

“Accelerating Development of the Renewable Energy Economy” Workforce Partnership Conference, N.C. Department of Commerce. Greensboro, NC, USA. October 2008.

“Market Adoption Factors of Hydrail Technology” 4th International Hydrail Conference, Valencia, Spain. June 2008.

“Economic Development from Landfill Gas: Carbon Credits Facilitate Job Creation” 11th Annual Landfill Methane Outreach Program Conference, U.S. Environmental Protection Agency. Baltimore, MD, USA. January 2008.

“Utilization of Rockingham County Landfill Energy Source” (with D. Grady) presentation to Board of Commissioners, Rockingham County, NC. August 2007.

“Landfill Gas Taskforce Update” presentation to Board of Commissioners, Columbus County, NC. May 2007.

“North Carolina Opportunities in Renewable Energy Manufacturing” presentation series to AdvantageWest, Research Triangle, NC Southeast, NC Northeast, and Charlotte Economic Development Partnerships. 2005.

SELECTED GRANT & CONTRACT AWARDS

“Measuring the Economic Impact of COVID-19 on the Regional Economy” N.C. Policy Collaboratory. $97,850. 2020 (Co-PI)

“Exploring the Viability of Small-Scale Forest Carbon Offsets” UNC General Administration Inter-Institutional Planning Grant. $75,000. 2018 (Co-PI)

“The OFFSET Workshop: Offsets for Future Forest Stewardship & Education Together” The Clabough Foundation. $6,610. 2017 (Investigator)

“Curriculum Development Contract TEC 3533/5533” College of Fine & Applied Arts, Appalachian State University. $3,200. 2017 (PI)

“Biogas as Local Economic Engine and Agent for Social Change” Eastern Research Group. $20,154. 2017 (Investigator)

“North Carolina Integrated Electric Utility Research Laboratory” (with J. Ramsdell, T. Cherry, B. Raichle, E. Miller and D. Young) UNC General Administration Research Opportunities Initiative Planning Grant. $48,307. 2016 (Co-PI)

“Appalachian Energy Center State Appropriation - FY16 and FY17” NC Department of Environmental Quality. $337,953. 2016 (Investigator)

“Examining metrics in compliance carbon offset protocols in U.S. forest projects” USDA NRE US Forest Service. $20,000. 2015 (Investigator)

“Subcontract for UNCW Greenhouse Gas Inventory” Good Company (Hinrichs, Proudfoot, and Skov, Inc). $5,928. 2014 (PI)

“Examining metrics in compliance carbon offset protocols in U.S. forest projects” USDA NRE US Forest Service. $40,000. 2014 (Investigator)

“Appalachian Energy Center - North Carolina University Energy Center Program July 1, 2013 through June 30, 2015” N.C. Department of Environment and Natural Resources. $506,930. 2014 (Investigator)

“Investigating the Economic Viability of a Municipal Solid Waste-to-Biofuels Facility in WNC” (with J. Ramsdell, A. Morgan, J. Ferrell and M. McKee) Biofuels Center of North Carolina/N.C. Department of Agriculture and Consumer Services. $65,722. 2013 (PI)

“Research Assistance to AIRE” Appalachian Institute for Renewable Energy. $24,975. 2012 (PI)

“Energy Savings: Environmental Performance Contracting in the United States” (with T. Cherry) Center for International Climate and Environmental Research - Oslo (CICERO). $2,650. 2012 (Co-PI)

“Renewable Energy Manufacturing Supply Chain Workshops” Advantage West. $4,000. 2012 (PI)

“ARRA - Edgecombe County Landfill Gas Assistance” Edgecombe County. $10,000. 2012 (PI)

“ARRA - Rockingham County Landfill Gas Project” Rockingham County. $10,000. 2011 (PI)

“Foothills Landfill Gas Project-Rutherford” Foothills Connect. $11,000. 2011 (PI)

“ARRA Wilkes County Landfill” Wilkes County. $7,000. 2011 (Investigator)

“Community-based Landfill Gas Utilization in Brazil - Phase II and Extension” US Environmental Protection Agency. $120,000. 2011 (Investigator)

“Landfill Gas for Community Development-Construction Phase” Z. Smith Reynolds Foundation. $25,000. 2011 (Investigator)

“Landfill Gas Utilization for Columbus County” Cape Fear RC&D Council. $6,000. 2011 (Investigator)

“Appalachian Energy Internship Program” (with M. Hoepfl, J. Cazier, J. Ramsdell, D. Scanlin and J. Tiller), NC Department of Administration, State Energy Office. $10,080. 2010 (Co-PI)

“Watauga County Energy Project Analysis” Watauga County. $1,975. 2010 (Lead PI)

“Appalachian Energy Internship Program” (with M. Hoepfl, J. Cazier, J. Ramsdell, D. Scanlin and J. Tiller), NC Department of Administration, State Energy Office. $485,857. 2010 (Co-PI)

“Green Economic Asset Mapping” Z. Smith Reynolds Foundation. $34,602. 2010 (Lead PI)

“Community-based Landfill Gas Utilization in Brazil - Phase I” US Environmental Protection Agency. $120,000. 2009 (Investigator)

“Community TIES Landfill Gas Development Phase III” Z. Smith Reynolds Foundation. $55,000. 2008 (Investigator)

“Community-based LFG Development Phase II” Golden LEAF Foundation. $125,000. 2007 (Investigator)

“Rural Landfill Gas Economic Development Demonstration Project” Golden LEAF Foundation. $97,360. 2006 (Investigator)

“Phase III Implementation of the State Energy Plan” NC State Energy Office. $466,765. 2006 (Investigator)

JWH-2
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Tab “2026”
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Tab “EIA860”

(2024 Early Release) https://www.eia.gov/electricity/data/eia860/

Utility ID	Utility Nam	Plant Code	Plant Name	State	County	Generator	Technology	Prime Mov
10171	Kentucky U	1354	Dix Dam	KY	Mercer	1	Conventior	HY
10171	Kentucky U	1354	Dix Dam	KY	Mercer	2	Conventior	HY
10171	Kentucky U	1354	Dix Dam	KY	Mercer	3	Conventior	HY
10171	Kentucky U	1355	E W Brown	KY	Mercer	10	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	11	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	3	Conventior	ST
10171	Kentucky U	1355	E W Brown	KY	Mercer	5	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	6	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	7	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	8	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	9	Natural Ga	GT
10171	Kentucky U	1355	E W Brown	KY	Mercer	SOLAR	Solar Phot	PV
10171	Kentucky U	1356	Ghent	KY	Carroll	1	Conventior	ST
10171	Kentucky U	1356	Ghent	KY	Carroll	2	Conventior	ST
10171	Kentucky U	1356	Ghent	KY	Carroll	3	Conventior	ST
10171	Kentucky U	1356	Ghent	KY	Carroll	4	Conventior	ST
10171	Kentucky U	1358	Haefling	KY	Fayette	1	Natural Ga	GT
10171	Kentucky U	1358	Haefling	KY	Fayette	2	Natural Ga	GT
11249	Louisville (	1363	Cane Run	KY	Jefferson	7A	Natural Ga	CT
11249	Louisville (	1363	Cane Run	KY	Jefferson	7B	Natural Ga	CT
11249	Louisville (	1363	Cane Run	KY	Jefferson	7S	Natural Ga	CA
11249	Louisville (	1364	Mill Creek (KY)	KY	Jefferson	2	Conventior	ST
11249	Louisville (	1364	Mill Creek (KY)	KY	Jefferson	3	Conventior	ST
11249	Louisville (	1364	Mill Creek (KY)	KY	Jefferson	4	Conventior	ST
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	1	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	2	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	3	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	4	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	5	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	6	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	7	Conventior	HY
11249	Louisville (	1365	Ohio Falls	KY	Jefferson	8	Conventior	HY
11249	Louisville (	1366	Paddys Run	KY	Jefferson	12	Natural Ga	GT
11249	Louisville (	1366	Paddys Run	KY	Jefferson	13	Natural Ga	GT
11249	Louisville (	6071	Trimble County	KY	Trimble	1	Conventior	ST
11249	Louisville (	6071	Trimble County	KY	Trimble	10	Natural Ga	GT
11249	Louisville (	6071	Trimble County	KY	Trimble	2	Conventior	ST
11249	Louisville (	6071	Trimble County	KY	Trimble	5	Natural Ga	GT
11249	Louisville (	6071	Trimble County	KY	Trimble	6	Natural Ga	GT
11249	Louisville (	6071	Trimble County	KY	Trimble	7	Natural Ga	GT
11249	Louisville (	6071	Trimble County	KY	Trimble	8	Natural Ga	GT
11249	Louisville (	6071	Trimble County	KY	Trimble	9	Natural Ga	GT

10171	Kentucky U	65406	LGE-KU Solar Sh	KY	Shelby	SSP	Solar Phot	PV

Unit Code	Ownership	Duct Burne	Can Bypas	RTO/ISO LI	RTO/ISO Lo	Nameplate	Nameplate	Summer C	Winter Cap
	S	X	X			9.4	0.8	10.5	10.5
	S	X	X			9.4	0.8	10.5	10.5
	S	X	X			9.4	0.8	10.5	10.5
	S	X	X			126	0.85	121	138
	S	X	X			126	0.85	121	128
	S	X	X			464	0.9	412	416
	J	X	X			123	0.85	130	130
	J	X	X			176.8	0.85	146	171
	J	X	X			176.8	0.85	146	171
	S	X	X			126	0.85	121	128
	S	X	X			126	0.85	121	138
	J	X	X			13		10	10
	S	X	X			556.9	0.9	475	479
	S	X	X			556.3	0.9	485	486
	S	X	X			556.5	0.9	481	476
	S	X	X			556.2	0.9	478	478
	S	X	X			20.7	0.85	12	14
	S	X	X			20.7	0.85	12	14
7ABS	J	X	N			260	1	229	229
7ABS	J	X	N			260	1	229	229
7ABS	J	N	X			287	1	233	233
	S	X	X			355.5	0.9	297	297
	S	X	X			462.6	0.9	391	394
	S	X	X			543.6	0.9	477	486
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.93	12.6	12.6
	S	X	X			13.7	0.8	12.6	12.6
	S	X	X			32.6	0.85	23	28
	J	X	X			178	0.85	147	175
	J	X	X			566.1	0.9	493	493
	J	X	X			199	0.85	159	179
	J	X	X			834	0.85	732	760
	J	X	X			199	0.85	159	179
	J	X	X			199	0.85	159	179
	J	X	X			199	0.85	159	179
	J	X	X			199	0.85	159	179
	J	X	X			199	0.85	159	179

J	X	X	2.1		1.7	1.7

Minimum L	Uprate or D	Month Upr	Year Uprat	Status	Synchroniz	Operating	Operating	Planned Re	Planned Re
2	N			OP	X	11	1925		
2	N			OP	X	11	1925		
2	N			OP	X	11	1925		
50	N			OP	X	12	1995		
50	N			OP	X	5	1996		
155	N			OP	X	7	1971		
50	N			OP	X	6	2001		
105	N			OP	X	8	1999		
105	N			OP	X	8	1999		
50	N			OP	X	2	1995		
50	N			OP	X	8	1994		
	N			OP	X	5	2016		
218	N			OP	X	2	1974		
225	N			OP	X	4	1977		
210	N			OP	X	5	1981		
215	N			OP	X	8	1984		
2	N			OP	X	10	1970		
2	N			OP	X	10	1970		
95	Y	5	2024	OP	X	6	2015		
95	Y	5	2024	OP	X	6	2015		
38	Y	5	2024	OP	X	6	2015		
115	N			OP	X	7	1974	6	2027
170	N			OP	X	8	1978		
175	N			OP	X	9	1982		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
2	N			OP	X	1	1928		
23	N			OP	X	7	1968		
81	N			OP	X	6	2001		
188	N			OP	X	12	1990		
80	N			OP	X	7	2004		
420	N			OP	X	2	2011		
80	N			OP	X	5	2002		
80	N			OP	X	5	2002		
80	N			OP	X	6	2004		
80	N			OP	X	6	2004		
80	N			OP	X	7	2004		

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Associatec	Sector Nar	Sector	Topping or	Energy Sou	Energy Sou	Energy Sou	Energy Sou	Energy Sou	Energy Sou
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	NG	DFO				
N	Electric Uti	1	X	NG	DFO				
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG	DFO				
N	Electric Uti	1	X	NG	DFO				
N	Electric Uti	1	X	SUN					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	WAT					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	BIT					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	BIT	SUB				
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					
N	Electric Uti	1	X	NG					

N	Electric Uti	1 X	SUN

Startup So	Startup So	Startup So	Startup So	Solid Fuel (	Carbon Ca	Turbines o	Time from	Fluidized B	Pulverized
				N	N	0	10M		
				N	N	0	10M		
				N	N	0	10M		
				N	N		1H		
				N	N		1H		
DFO				N	N		OVER		Y
				N	N		1H		
				N	N		1H		
				N	N		1H		
				N	N		1H		
				N	N		1H		
				N	N				
DFO				N	N		OVER		Y
DFO				N	N		OVER		Y
DFO				N	N		OVER		Y
DFO				N	N		OVER		Y
				N	N		1H		
				N	N		1H		
				N	N		12H		
				N	N		12H		
				N	N		12H		
NG				N	N		OVER		Y
NG				N	N		OVER		Y
NG				N	N		OVER		Y
				N	N	0	1H		
				N	N	0	1H		
				N	N	0	1H		
				N	N	0	1H		
				N	N	0	1H		
				N	N	0	1H		
				N	N	0	1H		
				N	N		1H		
				N	N		1H		
				N	N		1H		
NG				N	N		OVER		Y
NG				N	N		1H		
NG				N	N		OVER		Y
NG				N	N		1H		
NG				N	N		1H		
NG				N	N		1H		
NG				N	N		1H		
NG				N	N		1H		N

N N

Stoker Tec	Other Com	Subcritical	Supercritic	Ultrasuper	Planned N	Planned N	Planned U	Planned U	Planned N
		Y							
		Y							
		Y							
		Y							
		Y							
		Y							
		Y							
		Y							
		Y							
			Y						

Planned N	Planned D	Planned D	Planned N	Planned Er	Planned N	Planned Re	Planned Re	Other Plan	Other Mod
								N	
								N	
								N	

Other Mod	Multiple Fu	Cofire Fuel	Switch Between Oil and Natural Gas?
	N		
	N		
	N		
	Y	N	Y
	Y	N	Y
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	Y	N	Y
	Y	N	Y
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	
	N	N	
	N	N	
	N		
	N		
	N		
	N		
	N		
	N		
	N		
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	Y	Y	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N
	N	N	N

2025

JWH-2
Tab “PJM VM”

PJM's default values, effective January 1, 2025, for minor maintenance costs alone are $4.43/MWh for a simple-cycle combustion turbine, $2.11/MWh for a fossil steam turbine, and $1.21/MWh for a combined cycle unit

PJM Interconnection. 2024 VOM Education Session. April 16, 2024. https://www.pjm.com/-/media/DotCom/committees-groups/forums/tech-change/2024/20240416/20240416-item-03---4---cost-agent-introduction.pdf at 6.

Tech	$/MWh
CT	$4.43
ST	$2.11
CC	$1.21
ICE	$4.97

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 AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	))))	CASE NO. 2025-00113

AND

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	))))))	CASE NO. 2025-00114

VERIFICATION

I, Jason W. Hoyle, after being duly sworn, state that I am Director of Research, EQ Research, that I have personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and accurate to the best of my information, knowledge and belief.

Jason W. Hoyle
Director of Research
EQ Research

NORTH CAROLINA

COUNTY OF WATAUGA

Subscribed and sworn to before me by Jason w. Hoyle on this 27th day of August, 2025.

NICOLE KOONTZ
NOTARY PUBLIC
ASHE COUNTY, NC

Nicole Koontz
Notary Public

My Commission Expires: 2/25/28