COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	))))))))	**CASE NO. 2022-00402**

EXPERT TESTIMONY OF JOHN D. WILSON

ON BEHALF OF JOINT INTERVENORS METROPOLITAN HOUSING COALITION, KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY AND MOUNTAIN ASSOCIATION

July 14, 2023

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I. IDENTIFICATION & QUALIFICATIONS

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

A. My name is John D. Wilson. I am Vice President at Grid Strategies, LLC. Grid Strategies is based in the Washington, DC area, although my office is in Lexington, KY.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Joint Intervenors Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association.

Q. Please summarize your professional and educational background.

A. I received a BA degree from Rice University in 1990, with majors in physics and history, and a Master of Public Policy degree from the Harvard Kennedy School of Government, with an emphasis in energy and environmental policy, and economic and analytic methods.

Since 2019, I have been a consultant, first, at Resource Insight, Inc., and now at Grid Strategies, LLC. Previously, I was deputy director of regulatory policy at the Southern Alliance for Clean Energy ("SACE") for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Exhibit JDW-1.

Q. Have you ever testified before this Commission?

A. No.

Q. Have you ever testified before other Commissions?

A. Yes. I have testified more than forty times before utility regulators in six U.S. states and Nova Scotia, and I have appeared numerous additional times before various regulatory and legislative bodies.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate whether the retirement of seven fossil-fired electric generating units, namely E.W. Brown Unit 3, Ghent Unit 2, Haefling Units 1 and 2, Mill Creek Units 1 and 2, and Paddy's Run Unit 12, and adding resources proposed by Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") in their certificate of public convenience and necessity ("CPCN") requests in this proceeding fully satisfy the requirements of Senate Bill 4 ("SB4"). I am not offering any legal opinion on those requirements. The scope of my testimony is how to apply this standard using best practices in resource planning and adequacy evaluation.

I will also consider whether the requirements of SB4 are also satisfied by the alternative of joining PJM proposed by Witness Andrew Levitt, on behalf of the Sierra Club, the Lexington-Fayette Urban County Government, and the Louisville/Jefferson County Metro Government.

In addition to reviewing the Companies' application and a draft of Mr. Levitt's testimony, I have also reviewed a draft of Witness Michael Goggin's testimony on behalf of the Sierra Club, the Lexington-Fayette Urban County Government, and the Louisville/Jefferson

County Metro Government[1] and a draft of Witness Anna Sommer's testimony on behalf of Joint Intervenors.

Q. What are the requirements of SB4?

A. SB4 (2023 Ky. Acts 118) establishes a "rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit" unless the Commission finds that:

(a) The utility will replace the retired electric generating unit with new electric generating capacity that:

1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
2. Maintains or improves the reliability and resilience of the electric transmission grid; and
3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator;

(b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law; and

(c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency.

[1] I note that Witness Goggin and I are colleagues at Grid Strategies. While I have reviewed and am commenting here on Witness Goggin's testimony, we were each separately retained by different parties and our analyses were performed separately. My review occurred after his testimony was substantially complete.

II. SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. Based on my review of the SB4 requirements, the Companies have demonstrated that the proposed retirements rebut the presumption that they should remain in service. The proposed retirements should be approved by the Commission. (Section III). In approving the proposed requirements, the Commission should define a dispatchable electric generating capacity resource as a unit capable of following dispatch instructions between economic minimum and economic maximum when (i) the unit is physically capable of producing electricity and (ii) the unit's power source is available. (Section III.A). This definition includes solar, wind, storage and hybrid resources.

Furthermore, my review also finds that the proposed retirements are justified under SB4 if the Commission advances the proposal to join PJM (or another RTO), substituting for some or all of the proposed resource portfolio. (Section IV).

In reviewing the evidence, the Commission should consider concerns that the Companies' modeling overstates the resulting seasonal economic reserve margins. With respect to the proposed retirements, correcting those errors would reduce the need for additional capacity and most likely strengthen the evidence to overcome the rebuttable presumption in SB4. Addressing these concerns would lay the foundation for the Companies to provide stronger evidence in future SB4 retirement proceedings.

In reaching its decision, the Commission may also want to consider other financial impacts of the proposed retirements in the public interest. If the proposed retirements are approved, the cost of state tax breaks will be reduced as will the financial impacts of air pollution on people living in Kentucky and other states. (Page 38).

I have four suggestions for future improvements in the Companies' practices and methods, including:

1. The Companies should plan and contract for renewable energy facilities that include the technical and contractual opportunity to operate in downward dispatch or full flexibility operating modes and should generally avoid strict must-take contracts.
2. To the extent that the Companies' contractual opportunity to dispatch any renewable energy projects remains limited, such restrictions should not affect the Companies' valuation of their contribution to reliability, only grid services.
3. The Companies should update resource adequacy methods to identify opportunities to prepare for advanced operational practices, ensure accuracy in the reliability contribution of new resources, and support all-source procurement.
4. The Companies should modify the economic test for investment in the small-frame combustion turbine units to include an expected value for future below-threshold repair costs.

III. REVIEW OF SB4 REBUTTABLE PRESUMPTION REQUIREMENTS FOR THE GENERATION REPLACEMENT PORTFOLIOS OF THE COMPANIES

A. SB4 Section 2 (2)(a)(1): Is the new electric generating capacity dispatchable by the utility or independent system operator?

Q. Does SB4 require dispatchable replacement resources?

A. Yes. Section 2(2)(a)(1) calls for evidence sufficient for the Commission to find that a retired fossil unit will be replaced with new electric generating capacity that is dispatchable either by the utility or by the appropriate independent system operator, along with two additional factors.

But Section 2(2)(a)(1) does not specify more than that. It does not define dispatchable; does not specify the amount of replacement electric generating capacity; and does not exclusively require replacement with dispatchable resources.

Q. How do the Companies define dispatchable?

A. The Retirement Assessment adopts PJM's definition of dispatchable resources and suggests a definition that elaborates on certain implicit concepts.[2] I agree with that definition with one modification. I also find that the definition of dispatchable electric generating capacity should include storage resources, including battery technologies.

Q. What definition of dispatchable electric generating capacity would you suggest the Commission adopt?

A. From the perspective of industry practice, a good definition for dispatchable electric generating capacity resource is a unit capable of following dispatch instructions between economic minimum and economic maximum when (i) the unit is physically capable of producing electricity and (ii) the unit's power source is available. This definition is almost identical to that proposed in the Companies' Retirement Assessment, except that I do not modify the word "unit" with "generating" since the word "generating" would be defining itself.[3] The capability to produce electricity is the act of generation.

Q. Are large-scale energy storage systems considered to be a dispatchable capacity resource?

A. Yes. Utilities and independent system operators usually classify utility-scale energy storage systems as a capacity asset.[4] For example, Lazard defines a standalone utility-scale energy

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[2] Kentucky Utilities Company and Louisville Gas and Electric Company, *2023 Fossil Fuel-Fired Electric Generating Unit Retirement Assessment*, Exhibit SB4-1, Case No. 2023-00122, at 7 (Ky. PSC May 10, 2023) ("Retirement Assessment").

[3] Retirement Assessment at 7.

[4] I am aware that some utilities prefer to classify battery storage as a transmission asset for cost recovery purposes. In addition to storing and dispatching energy, large-scale battery storage plants also provide services that are similar to facilities that are considered part of the transmission system, such as voltage regulation. When investment in

storage system as "designed for rapid start and precise following of *dispatch* signal," and a system paired with solar or wind generation as designed "to better align timing of [solar or wind] generation with system demand, reduce curtailment and provide grid support."[5] In my experience, whether battery storage projects are pilots or represent a substantial portion of system resources, industry practice is to recognize the contribution of battery storage to reliability as a capacity asset.[6]

Large-scale energy storage systems have been an important part of our electric system since at least 1973, when the Ludington Pumped Storage facility was placed in service.[7] Regionally, the most significant plant is the Tennessee Valley Authority ("TVA")'s 1,616 MW Raccoon Mountain pumped storage hydro system. Raccoon Mountain was built because the use of electricity was typically much greater in the daytime than at night, but the TVA's nuclear and coal generators generally produced power at a constant rate. For over four decades, Raccoon Mountain has enabled the TVA to better align the timing of its generation with system demand.

Although most large-scale battery storage systems do not operate at the scale or with the duration that is provided by the Raccoon Mountain plant, their function is essentially the same. Operated in sequence, five or six four-hour battery storage units can supply power on the same terms as Raccoon Mountain.

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battery storage plants is primarily based on requirements to maintain service quality, the plants may be classified as transmission assets for cost recovery purposes.

[5] Lazard, *2023 Levelized Cost of Energy+* at 16 (Apr. 2023), https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/ (emphasis added).

[6] By industry practice, I am referring to the operating rules of RTOs such as PJM and CAISO, regulatory decisions in several jurisdictions where I have appeared, and many utility filings such as resource plans or capacity investment applications. Redefining Resource Adequacy Task Force, *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation*, Energy Systems Integration Group (Feb. 2023) at 5, https://www.esig.energy/new-design-principles-for-capacity-accreditation/ ("ESIG CA Report").

[7] Smaller pumped storage facilities date back much earlier.

Q. Is it meaningful to make a distinction between the capacity provided by plants that re-deliver power received from the grid and those that deliver power created from a fuel source?

A. No, batteries and other storage devices are also dispatchable generation resources. From a utility operator's point of view, the dispatch of energy to serve customers' load does not depend on whether the energy comes from a pumped storage plant, a battery plant, a renewable (or hybrid) plant, or a fossil-fueled plant. Every energy resource has limitations in terms of the rate, duration, and reliability of dispatch in response to system requirements.

In 2022, MISO added electric storage resources ("ESRs") to its market portfolio.[8] MISO classifies ESRs as a capacity resource, provided they have a 4-hour discharge capability and meet several other operating criteria.[9] MISO's definition of planning resources includes load modifying resources, energy efficiency resources, and capacity resources. MISO's capacity resource definition includes ESRs, generation resources, and demand response resources.[10] MISO's approach to ESRs is similar to that of many other utilities and RTOs in classifying ESRs as equivalent to traditional generation resources for capacity planning purposes.

Another reason it is meaningless to distinguish between storage-supplied capacity and traditional generation-supplied capacity is that from a strictly technical point of view, batteries do generate electricity through chemical processes. Fuel cells are another form of generation that also relies on chemical production of electricity. Both fuel cell and lithium-ion batteries produce energy as the result of physical movement of chemicals and the electro-chemical release of energy. Electricity cannot truly be stored in the same way that

[8] MISO, *New Resource Type Supports Energy Transition* (Sept, 6, 2022), https://www.misoenergy.org/about/media-center/miso-introduces-electric-storage-resource-to-market-portfolio/.

[9] MISO, *Resource Adequacy Business Practice Manual,* BPM-011-r28 at 73 (May 31, 2023), https://www.misoenergy.org/legal/business-practice-manuals/ ("MISO RA BPM-011").

[10] MISO RA BPM-011 at 28.

water or vegetables may be stored in a container for future use. Each electric storage technology relies on the conversion of electric energy into a form of potential energy that is later used to generate electricity upon dispatch by an operator.

Q. Is solar power dispatchable?

A. Yes. The Retirement Assessment correctly explains that a solar facility in full sun is dispatchable by adjusting the output from economic minimum to maximum.[11] Some people may expect that a solar facility should be fully dispatched at all times because the cost to dispatch is zero and thus dispatched as a must-take resource. Counter-intuitively, curtailing solar during normal operating conditions can actually be of financial benefit.

The revision of utility operating practices to include optimal dispatch of solar—including downward dispatch—is likely to result in system cost savings. This is best shown in a study by Energy and Environmental Economics ("E3") in collaboration with Tampa Electric. The E3 study showed increased system benefits of utilizing economic dispatch of solar capacity relative to a must-take operating practice. The E3 study found that once the annual solar penetration potential reached about 15% of Tampa Electric's annual energy requirement, significant annual production cost savings could result from optimal dispatch.[12]

Planned curtailment of solar allows the resource to contribute to both footroom (additional curtailment) and headroom (ramping up solar to respond to increased demand).[13] Counter-intuitively, curtailment of solar allows for fewer thermal generation units to be placed online because the curtailment of solar results in a system that requires thermal generation units to provide less footroom and headroom, as illustrated in Figure 1. Those units that are placed online can be dispatched to a higher, more efficient level of output.

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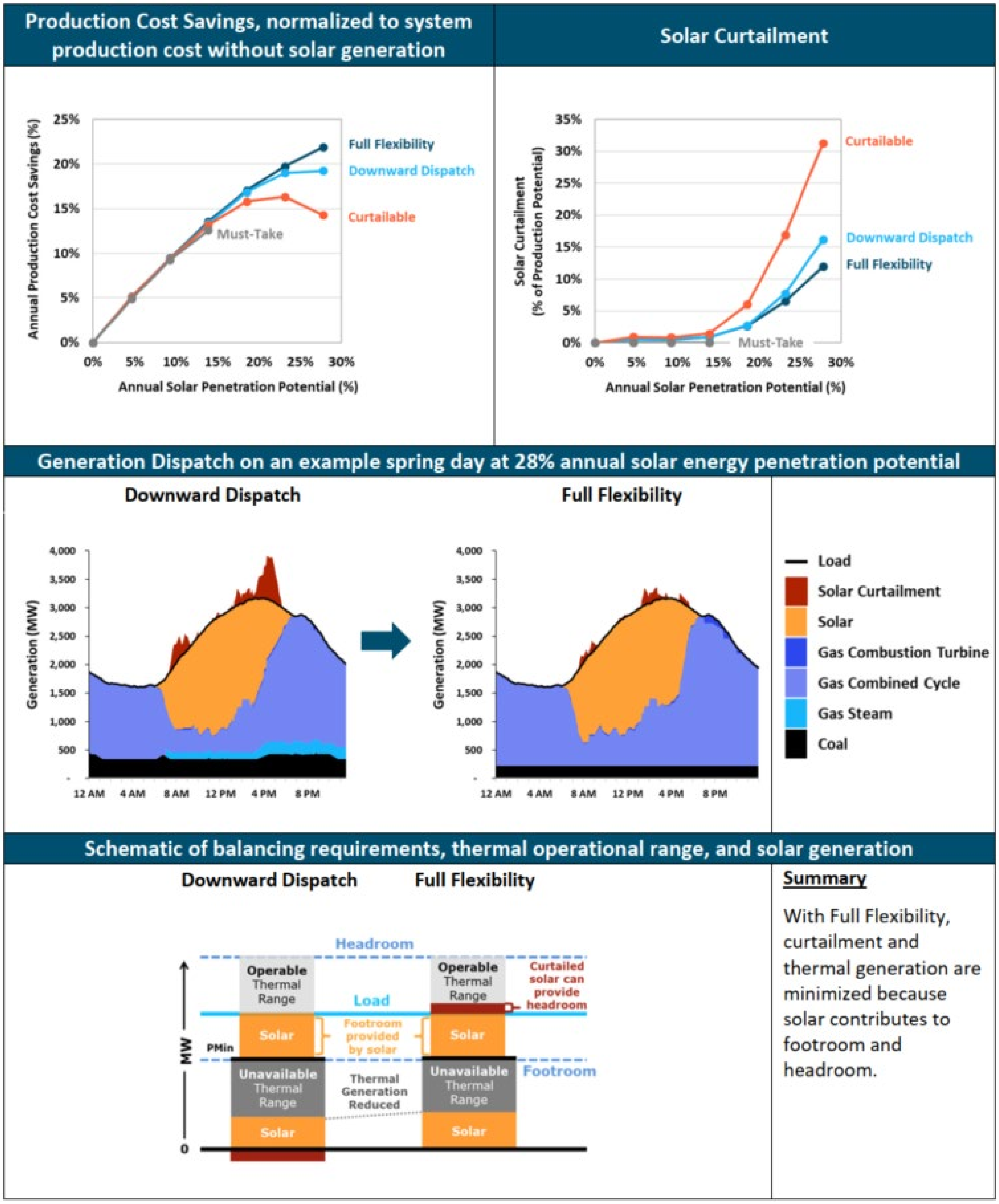
[11] The same principles apply to wind resources, which have similar dispatchability.

[12] Energy and Environmental Economics, Inc., Investigating the Economic Value of Flexible Solar Power Plant Operation at 34 (Oct. 2018), https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf ("E3 Study").

[13] *Id.* at 12.

Figure 1: E3 Study Findings for "Full Flexibility" Operating Mode[14]



[14] *Id.* at 34 (Figure 8 from the original).

Q. Do the Companies recognize the economic value of flexible solar plant operation?

A. Not in this application, although the Companies allow for it in the future. In response to a data request, the Companies' state that they "would not plan to curtail owned solar under normal operating conditions and did not attempt to quantify any financial benefit in the Financial Model."[15]

The Companies do recognize that at some point, such value could exist. In response to a data request, the Companies state that they will evaluate whether to "operate their owned solar in downward dispatch or full flexibility operating mode if it is economically prudent to do so."[16] However, with respect to the solar PPA facilities, the Companies have not negotiated for the right to curtail those facilities' output for the purposes of operational reserves to supply headroom and footroom. The Companies justify this on the basis that they "have not yet integrated sufficient solar resources to justify any additional expense for the right to curtail the solar PPA facilities' output."[17]

Q. Should the Companies be planning to utilize the economic value of flexible solar plant operation in the future?

A. Yes, the Companies should avoid strict must-take contracts by planning and contracting for solar power facilities that include the technical and contractual opportunity to operate in downward dispatch or full flexibility operating modes. The Companies' current and proposed solar resources will total to about 8% of annual energy requirements,[18] significantly less than the 15% annual penetration that the E3 study suggests reflects

[15] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Joint Intervenors' Third Set of Data Requests, Question 2(a) (May 31, 2023) ("LGE & KU Response to JI Third Data Request Q").

[16] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Joint Intervenors' Fourth Set of Data Requests, Question 1 (June 27, 2023) ("LGE & KU Response to JI Fourth Data Request Q").

[17] LGE & KU Response to JI Third Data Request Q2(b).

[18] Direct Testimony of David S. Sinclair, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 19 (Dec. 15, 2022).

Tampa Electric's threshold for economic value of flexible solar. To prepare for future opportunities, the proposed solar resources should be technically and contractually available for operation in flexible operation mode in the future.

If the proposed resource portfolio is approved, the Companies' solar resources will be comprised of the current resources (about 1% of annual energy requirements), owned solar (about 2%), and solar PPAs (about 5%). Assuming that the 15% threshold for flexible solar operation found for Tampa Electric also applies to the Companies' system, the solar PPAs would represent about a third of the solar resources when that threshold is reached. Failing to secure an opportunity to operate such a substantial portion of the Companies' solar projects as flexible resources would reduce the potential level of grid services from solar.

Even in advance of reaching the 15% threshold, there may be economic reasons to downward dispatch the solar PPAs that would not be allowed under a typical must-take PPA contract. For example, if the solar PPA projects were operating under full sun and an approaching weather front caused a rapid, simultaneous reduction of generation, the loss of several percent of system generation in a matter of minutes could affect system power quality. If the solar PPA projects cannot be pre-curtailed to achieve a more gradual reduction in output, then operators may choose to operate other generation facilities in a more complex and costly manner to manage the power fluctuations.

For both advance planning and to provide system operators with greater control over the output of the solar PPA projects, it would be prudent for the Companies to include provisions for the right to curtail solar PPA facilities' output in contracts that they are negotiating. Negotiating the rights to curtail solar PPA facilities' output would ensure that the facilities are designed to allow for economic dispatch. It is my understanding that optimal technology to enable this capability is inexpensive to install during construction.

Activation of the capability could be deferred and available to the Companies at a pre-negotiated price.

Q. Are hybrid renewable-storage plants dispatchable?

A. Yes, the combination of dispatchable renewable (solar or wind) plants and storage plants should be viewed as dispatchable generation capacity because each component of such plants also has that property. As discussed below in Section III.B, the combination of renewable generation and battery storage can actually represent more than the sum of its parts, so it is appropriate to recognize these units (or the combination of these units across the utility system) as having enhanced capacity value.

While the Companies are not proposing any hybrid plants in this proceeding, the Commission will be making decisions regarding which types of units are considered to be dispatchable generating capacity for purposes of SB4 compliance. I suggest that it would be expeditious for the Commission to determine that hybrid plants are also dispatchable generating capacity in its decision rather than having the issue raised separately in a future proceeding.

Q. What is your conclusion on this requirement of SB4?

A. The new electric generating capacity proposed by the Companies will be dispatchable, with the exception of the solar PPAs. As explained above, with negotiated changes to the solar PPA contracts, those resources could also be fully dispatchable. To the extent that the Companies' contractual opportunity to dispatch the renewable energy projects such as the solar PPAs is limited, such restrictions should not affect the Companies' valuation of their contribution to reliability.

B. SB4 Section 2 (2)(a)(2): Will the new electric generating capacity maintain or improve the reliability and resilience of the electric transmission grid?

1. Reliability Requirement

Q. Please summarize the Companies' Retirement Assessment of the reliability requirement.

A. The Companies' Retirement Assessment finds that the Companies' proposed electric generating capacity will improve the overall reliability of the electric transmission grid. The Companies calculate that the loss-of-load expectation ("LOLE") will decline from 0.45 to 0.28 days/10 years.[19] Similarly, the Retirement Assessment report finds that seasonal reliability will improve in the summer. Even though the report states that seasonal reliability will marginally decrease in the winter, it finds that the LOLE will remain well below the North American Electric Reliability Corporation's ("NERC") guideline of one day and the Companies' current standard of 3.57 days in 10 years.

Q. Is the Companies' method to evaluate reliability reasonable?

A. Yes, I believe the method selected by the Companies is reasonable in the present circumstances, with the caveat that others are raising significant concerns about the Companies' implementation of its method. The Companies' primary method for determining reliability is the seasonal economic reserve margin method.[20] Using this method, reliability costs (measured as the value of lost load) are considered along with the cost of additional capacity and energy production.[21] The economic minimum establishes a seasonal capacity target, with the difference between that target and the forecast weather-normal system coincident peak load being referred to as the capacity reserve margin.

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[19] Retirement Assessment at 14.

[20] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Commission Staff's First Request for Information, Question 47(a), Attachment 1 at 81, (Mar. 10, 2023) ("LGE & KU Response to Staff Initial Q47(a)").

[21] LGE & KU Response to Staff Initial Q47(a), Attachment 1 at 91–94.

As I understand it, the economic minimum results in a capacity reserve margin of 17% for summer and 24% for winter, which the Companies have determined to be equivalent to a LOLE of 3.57.[22] However, it should be emphasized that the Companies' method does not establish a LOLE of 3.57 as a standard on its own, it is the LOLE that results from a particular portfolio that is minimally consistent with the Companies' economic reserve margin method.[23]

One reason I generally agree that the Companies' method for evaluating reliability is reasonable is that unlike the LOLE method (NERC's guideline), the economic reserve margin method takes into account the duration and the magnitude of reliability events. Detailed review of the Companies' reserve margin calculations is beyond the scope of my testimony, but I will discuss several general concerns that the Commission should consider in evaluating the Companies' findings on system reliability.

- First, I understand that Mr. Goggin has reviewed the Companies' assumptions and methods for reflecting the value of lost load in its analysis, and has concerns that the value is too high, resulting in an excessive reserve margin.
- Second, the Companies' modeling may not accurately reflect the contribution of imported power to meet demand during peak periods. I understand that Mr. Goggin and Ms. Sommer are filing testimony that discusses incorrect limitations on the capability of transmission capacity to deliver imports. The opportunity to rely on imports is also a central theme of Mr. Levitt's testimony regarding the alternative of membership in an RTO, which I will discuss in Section IV below. However accessed, availability of imports is of measurable benefit to system reliability.

[22] Retirement Assessment at 13.

[23] Other portfolios consistent with the Companies' economic reserve margin method could have different (higher or lower) LOLE results. If the cost of capacity or production in such portfolios is lessened, then the resulting economic reserve margin would likely have a smaller LOLE because the optimal level of capacity to avoid lost load would be greater. In such circumstances, the balance between additional capacity costs and the benefits of avoiding lost load can be found at a lower level of LOLE.

- Third, I understand Mr. Goggin is raising concerns with the capacity value of solar, wind, and battery storage resources. Review of these assumptions is beyond the scope of my testimony. If the capacity value of any of these resources were increased, the Companies' need for other types of capacity would be reduced.

For each of these three issues, if the Commission determines that the Companies' modeling overstates the resulting seasonal economic reserve margins, then correcting those errors would reduce the need for additional capacity. With respect to the proposed retirements, such a change would most likely strengthen the evidence to overcome the rebuttable presumption in SB4 and would lay the foundation for the Companies to provide stronger evidence in future SB4 retirement proceedings.

A fourth issue with the Companies' current reliability standard method is that looking forward, it may not fully consider the performance characteristics of new technologies.

Q. Are reliability standards evolving in response to new technologies?

A. Yes. Renewable energy (especially wind and solar) and battery storage technologies have different performance characteristics than traditional thermal generation technologies. Furthermore, grid-enhancing technologies are enabling transmission operators to assist in meeting system reliability standards.

Historically, system reliability has been closely associated with the difference between system capacity and peak demand. A shortfall in capacity, due to decommissioning of existing resources or load growth, can demonstrate need sufficient to justify a CPCN application. An excess of capacity could result from changes in demand, economic opportunities to procure low-cost capacity, or an economic decision to procure capacity in a large block that exceeds demonstrated need. Transmission investments were built to serve the capacity and demand. It has usually been taken for granted that energy would be sufficient given sufficient capacity.

The combination of increased market energy transactions with distant suppliers and the cost-effectiveness of renewable resources, battery storage, and distributed energy resources ("DERs") is driving an evolution in reliability standards. Reliability may be assured not just with a "firm capacity" resource (which may not be so firm in extreme weather conditions) but also with a combination of resources which are shown to be, in combination, sufficiently certain to perform during a wide range of circumstances. The system peak may be met with conventional generation, surplus energy generated at an earlier hour and stored for the peak, or via transmission. As the lines blur between capacity, energy, and transmission, new methods of planning for and measuring reliability outcomes are being developed.

Measurements of the Companies' reserve margin and forecast LOLE provide an incomplete and perhaps even misleading indication of system reliability. Perhaps most obviously, neither considers reliability issues related to storm impacts on the distribution system, which is nearly 100% of customer experience with reliability events.[24] Of course, distribution system planning is not at issue in this proceeding, so I will move on.[25]

[24] Trevor Houser et al., *The Real Electricity Reliability Crisis*, Rhodium Group (Oct. 3, 2017), https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/. During the period January 2011 to March 2023, utilities reported 62 electric disturbance events affecting Kentucky to the U.S. Department of Energy on Form OE-417. Of these 62 electric disturbance events, only 28 include reports of customers being affected, including 26 weather-related events, one physical attack, and one transmission interruption. Database obtained from Michael Mabee, *OE-417 Electric Disturbance Events Database* (updated through Mar. 2023), https://michaelmabee.info/oe-417-database/. However, reports on Form OE-417 are incomplete. For example, no utility submitted an electric disturbance event in Kentucky for December 23, 2022. Verified at US Department of Energy, *Electric Disturbance Events (OE-417) Annual Summaries* (2022), oe.netl.doe.gov/OE417_annual_summary.aspx.

[25] The gas unit curtailments and resulting load shedding during Winter Storm Elliott (December 23, 2022) is an example of a storm-triggered resource adequacy reliability event, which is at issue in this proceeding. LGE & KU Response to Staff Initial Q58(a)(b).

Considering reliability from a resource adequacy perspective, the problem with LOLE is that it "does a poor job of differentiating shortfalls, which, depending on their length and duration, can have unequal impact on consumers and can require different mitigation options."[26] Furthermore, the 1-day-in-10-years LOLE criterion is arbitrary in nature, as it "was developed in the middle of the 20th century, with limited rationale as to its selection and limited evaluation of the costs and benefits of achieving this definition of reliability."[27]

As the Energy Systems Integration Group's ("ESIG") Redefining Resource Adequacy Task Force points out in its report, "[t]he reliance on the LOLE metric was adequate in traditional resource adequacy analysis because shortfalls tended to share similar characteristics, largely occurring during peak load events and caused by randomly occurring forced outages of the conventional fossil fleet."[28] ESIG is a nonprofit that brings together staff from grid operators, utilities, government laboratories, consulting firms, and other energy organizations to collaborate on studies and other activities that advance grid transformation and energy systems integration. The ESIG Resource Adequacy Report recommends expanding resource adequacy studies to consider multiple metrics so that system planners can "right-size mitigations to meet the system's specific reliability needs."[29]

Furthermore, the traditional understanding of the reserve margin is being revised, as discussed in ESIG's 2023 report on capacity accreditation:

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[26] Redefining Resource Adequacy Task Force, *Redefining Resource Adequacy for Modern Power Systems,* Energy Systems Integration Group (2021) at 10, https://www.esig.energy/resource-adequacy-for-modern-power-systems/ ("ESIG RA Report").

[27] ESIG RA Report at 25.

[28] ESIG RA Report at 10.

[29] ESIG RA Report at 12.

> With risk shifting to periods outside of the single peak demand period, a static planning reserve margin based on a percentage of peak demand is no longer appropriate. The capacity contribution of different resource types will change significantly as the underlying resource mix changes.[30]

Historically, capacity accreditation has been based on historical performance, with nominal capacity adjusted by forced outage rates and planned maintenance/refueling periods. Integration of renewable, energy storage, and load flexibility resources has led to the adoption of modeled, or probabilistic, accreditation techniques, notably effective load carrying capability ("ELCC").

Using performance-based accreditation for some resources and modeled techniques for others leads to inequitable evaluation of resources. While the ELCC method considers weather- and load-correlated performance as well as forced outage rates for renewable resources, forced outage rates used for thermal resources understate the risks of weather-correlated forced outages. In some cases, utilities have moved to using the ELCC method for all capacity resources. Nova Scotia Power's current resource planning method not only assigns ELCC values to wind, solar, battery, and demand response resources, but also assigns a "diversity benefit" for combinations of renewables and storage and adopted the ELCC method for existing thermal and hydroelectric resources.[31]

Q. Have the Companies updated their reliability methods in response to new technologies?

A. Only partially. During the recent (May 2023) hearing on the proposed Economic Development Rate contract between KU and the Bitiki cryptocurrency mining facility, Mr. Stuart Wilson stated that as utilities adopt more renewable (particularly solar) and limited

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[30] ESIG CA Report at 5.

[31] Nova Scotia Power, *Powering a Green Nova Scotia, Together. 2020 Integrated Resource Plan,* Appendix B at 56–57, Appendix J at 9 (Nov. 27, 2020), https://irp.nspower.ca/documents/final-irp-report/.

duration (storage) resources, "reserve margin is less meaningful as a reliability metric … as we have more [solar and storage resources] … it's a difficult metric to use."[32]

One update to the Companies' reliability methods has been the adoption of capacity contribution methods for limited-duration resources. The Companies' method for these calculations is described as follows:

> The capacity contributions computed for limited-duration resources in Exhibit SAW-1, Appendix D are similar to the effective load carrying capability (ELCC) that RTOs compute for limited-duration resources, but the calculation is not the same. Capacity contribution for a limited duration resource is computed as the ratio of the resource's impact on LOLE to the LOLE impact of a like-amount of SCCT capacity. Based on this calculation, the capacity contribution for a SCCT would be 1 (i.e., 100 percent). The capacity contribution for other thermal resources should also be 100 percent because differences in availability are modeled using unit-specific forced outage rates.[33]

The Companies' use of an ELCC-like method is a step forward because it recognizes that not all nameplate megawatts of capacity are the same from a perspective of reliability contribution. However, because the Companies' method is based on benchmarking against an assumed 100% available resource, which I believe everyone understands is not a reasonable expectation of any unit's performance, more remains to be done.

Industry practices are evolving such that continuing to incorrectly assume that thermal resources have a 100% capacity contribution will misrepresent the relative reliability of those units. A recent report by Astrapé, the firm that provides the Companies' reliability software ("SERVM"), states that "capacity accreditation of conventional resources is often

[32] Case No. 2022-00371, Ky. PSC, May 31, 2023 HVT 10:20:09 – 10:21:01, https://www.youtube.com/watch?v=CQ3vs4tHEUE.

[33] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Commission Staff's Supplemental Request for Information, Question 81 (May 4, 2023) ("LGE & KU Response to Staff Supplemental Q").

overstated."[34] Not only is it important to accurately compare the characteristics of conventional and new resource technologies, but the report explains that fully accounting for "forced outages, correlated outages, weather dependent outages, and fuel unavailability of traditional thermal resources … further creates differentiation between types of traditional, thermal units that did not previously exist."[35]

Correlated outages have been documented in most regions of the country, including the SERC Reliability Corporation ("SERC") region. According to one study, "managerially significant correlated failures are present" in SERC and several other regions.[36]

The Companies do not appear to be updating their reliability methods to consider these factors. As the above response further states, "The Companies are not aware of cases where ELCC is computed for thermal resources."[37] Furthermore, the Companies "assumed no correlation between forced outage[s]."[38] As I have discussed, utilities have computed the ELCC for thermal resources and this approach is recommended by Astrapé to address the correlation between forced outages.

Rather than accounting for thermal resource performance uncertainty in each individual unit's capacity accreditation by assuming that unit outages are uncorrelated, the Companies' method effectively socializes a portion of that uncertainty to load. The resulting reserve margin relies on an understated risk of thermal generation unit outage and an overstated general system risk. The Companies argue that in spite of handling capacity

[34] Joel Dison et al., *Accrediting Resource Adequacy Value to Thermal Generation*, Astrapé, at 6, (March 2022), https://www.astrape.com/wp-content/uploads/2022/10/Accrediting-Resource-Adequacy-Value-to-Thermal-Generation-1.pdf ("Astrapé RA Report").

[35] Astrapé RA Report at 8.

[36] Sinnott Murphy et al., *Resource Adequacy Risks to the Bulk Power System in North America*, 212 Applied Energy 1365, (Feb. 15, 2018), https://www.sciencedirect.com/science/article/pii/S0306261917318202?via%3Dihub.

[37] LGE & KU Response to Staff Supplemental Q81.

[38] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Sierra Club's Supplemental Request for Information, Question 7(b) (May 4, 2023) ("LGE & KU Response to Sierra Club Supplemental Q").

accreditation differently than some RTOs, their resource adequacy modeling treats thermal and non-thermal resources on an equitable basis, a view that I think deserves to be skeptically received.

Based on my review of ESIG's resource adequacy and capacity accreditation reports, the E3 study of the Tampa Electric system, and the Nova Scotia Power findings regarding the diversity benefit of combining renewable energy with battery storage, and the potential for gas or coal fleet correlated outages as discussed in the Astrapé report, I encourage the Companies to consider updating their resource adequacy methods. As discussed above in Section III.A, at the levels of solar and storage that are currently proposed for their portfolios, the Companies' conclusions about system reliability with the proposed retirements and resource additions are likely to be reasonable. But for future resource additions, reliability planning methods may need to be improved.

There are three benefits to moving expeditiously to more advanced planning methods. First, the Companies will be able to identify opportunities to prepare for operational practices such as flexible dispatch of solar resources and utilization of grid-enhancing technologies.[39] Second, by adopting those methods in advance of larger scale deployment of new resources, the Company will be prepared to more accurately represent their contribution to reliability. Third, these advanced planning methods can be used to support all-source procurement, allowing the utility to seek market bids for a mix of different resource technologies that can be optimized in a portfolio that meets the Companies' performance requirements.

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[39] Grid-enhancing technologies involve the deployment of operational practices, hardware, and software to implement dynamic line ratings, advanced power flow control, and grid topology optimization. These technologies can increase the capacity and flexibility of the electric transmission system. Jay Caspary, *The Role for Grid-Enhancing Technologies*, ESIG: Energy Systems Integration Group (Jan. 2022), https://www.esig.energy/the-role-for-grid-enhancing-technologies/.

Q. If the Companies kept Brown 3, Ghent 2, and Mill Creek 1 and 2 online, could there be increased reliability risks at those plants?

A. If the Companies kept some or all of these coal units online for "cold reserve" or some other purpose resulting in relatively limited use, the coal units are likely to demonstrate lower reliability during cold weather conditions, for two reasons.

First, the Companies state that when inventory levels are extremely low, there is "greater potential for coal piles to sufficiently freeze and cause operational problems."[40] For infrequently-used coal plants, inventory levels are likely to be maintained at a low level and, if the plant is used during cold weather, the inventory could drop to levels that would put the piles at risk of freezing.

Second, the Companies have documented issues related to frozen coal that have resulted in derates.[41] While these events are considered in the forced outage rates, infrequent operation of these plants could increase the likelihood of such outages due to infrequent operation and maintenance activities. I would expect such outages to become more likely because infrequently-used coal plants would be called upon only during the coldest weather when it would be most difficult to address any issues with coal that has been frozen in place during an extended period of inactivity at the unit.

2. Resilience Requirement

Q. What is your opinion of the Retirement Assessment's analysis of the resilience requirement?

A. The Companies' Retirement Assessment discusses "start-up times, ramp rates, and range of dispatchable capacity … [as the] objective, established metrics the Companies can use to

[40] LGE & KU Response to JI Third Data Request Q4.

[41] *Id.*

determine responsiveness to events affecting load."[42] His testimony demonstrates that the Companies' proposed resources improve upon the retired resources based on these metrics.[43] For example, the proposed owned solar resources could have a start-up time and ramp rate of 120 MW per minute, and a dispatchable capacity range of 0 to 120 MW.[44]

However, additional considerations should be included in an evaluation of resilience. A 2020 NARUC report discusses eight resilience traits in the context of DERs, including:

1. **Dispatchability**: Resilient DERs can respond to a disruption at any time with little to no advance warning.
2. **Islanding Capability**: Resilient DERs have the ability to island from the distribution grid and serve load during a broader outage.
3. **Siting at Critical Loads/Locations**: Resilient DERs reside at critical loads or at critical points on the grid (e.g., areas of high residential density).
4. **Fuel Security**: Resilient DERs do not rely on the availability of a limited physical fuel to provide power.
5. **Quick Ramping**: Resilient DERs are capable of changing output quickly to match rapidly changing load.
6. **Grid Services**: Resilient DERs can provide voltage support, frequency response, and other grid services.
7. **Decentralization**: Resilient DERs are sized and sited to support a load in the distribution system.

[42] Retirement Assessment at 15.

[43] Retirement Assessment, Table 6 at 16.

[44] LGE & KU Response to JI Fourth Data Request Q2.

8. **Flexibility**: Resilient DERs can be deployed quickly and cheaply (when compared to centralized generation, transmission, and/or distribution) at locations and times where resources are needed.[45]

While NARUC developed these eight traits in the context of evaluating DER deployment strategies, five of the eight characteristics apply broadly to a utility system's overall performance. The three that are more particular to DER functionality are islanding capability, siting at critical loads/locations, and deployment flexibility. These are resilience benefits that are not generally provided by utility systems that rely mainly on central station generation. The Companies could improve these aspects of resilience by promoting a DER deployment strategy.

With respect to the remaining five traits, the Companies' proposed resources improve upon the retired resources, as follows:

1. **Dispatchability**: The Retirement Assessment demonstrates that the Companies' proposed resources have shorter start-up times and a wider dispatchable range than the resources proposed for retirement.
2. **Islanding Capability**: n/a
3. **Siting at Critical Loads/Locations**: n/a
4. **Fuel Security**: The units proposed for retirement each generally operate on a single fuel. The proposed resources add fuel diversity to the Companies' system by substantially increasing the amount of solar power. The battery storage unit is capable of being charged from other generation resources using any available fuel source.
5. **Quick Ramping**: The Retirement Assessment demonstrates that the ramp rate for the Companies' proposed resources would be faster than for the resources proposed for retirement.

[45] Kiera Zitelman, *Advancing Electric System Resilience with Distributed Energy Resources: A Review of State Policies*, National Association of Regulatory Utility Commissioners, at 9 (Apr. 2020).

6. **Grid Services**: Voltage support is maintained or improved by the Companies' proposed resources, which include the addition of transmission system upgrades. This finding is supported by the Companies' study of impacts on the transmission system.[46] For example, the Companies explain that retirement of Brown Unit 3 is unlikely to result in voltage support issues unless a combination of multiple events occurs: Cooper 1 and 2 are unavailable and redispatch of Brown CT generators (Units 5-11) out of economic merit order is insufficient to alleviate all the voltage support issues. The Companies' proposed Brown NGCC and BESS units would fully address this concern.[47] Battery storage can be a superior technology for providing grid services since it can be distributed across the Companies' grid, providing voltage support and other ancillary services on a more localized basis.
7. **Decentralization**: The Companies' proposed resources would increase decentralization by locating new solar units at locations that do not currently supply power to the grid. If the Companies also implemented a DER deployment strategy, including battery storage, this aspect of resilience could be improved.
8. **Flexibility**: n/a

C. SB4 Section 2 (2)(a)(3): Will the new electric generating capacity maintain the minimum reserve capacity requirement established by the utility's reliability coordinator?

Q. Is "minimum reserve capacity requirement" defined in Kentucky law?

A. I do not find any definition of minimum reserve capacity requirement or any legal obligation to establish such a requirement in Kentucky law. It is unclear how this portion of

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[46] Kentucky Utilities Company and Louisville Gas and Electric Company, *Generation Replacement & Retirement Scenarios – Expected Impacts on the Transmission System*, Exhibit SAW-2 Confidential Workpapers, Case No. 2022-00402 (Nov. 18, 2022).

[47] LGE & KU Response to Staff Supplemental Q55(a).

the statute might be implemented if the utility's reliability coordinator does not have a minimum reserve capacity requirement.

Commission precedent has recognized the role of a minimum capacity requirement and relied upon requirements established by the utility. To obtain a CPCN pursuant to KRS 278.020(1), a utility must demonstrate a "need" for such facilities and an "absence of wasteful duplication."[48] In 2011, the Commission approved a joint application by the Companies to retire their coal-fired generating facilities at Cane Run, Green River, and Tyrone to comply with new and pending environmental regulatory requirements. Based in part on the Companies' finding that the retirements would contribute to a capacity shortfall that would result in a 2016 reserve margin of only 4%, compared to the target reserve margin of 16%, the Commission held that the Companies had established need to address capacity shortfalls associated with the need to retire coal-fired generating units.[49]

I note that while the Commission accepted the Companies' reserve margin evidence in their 2011 application, it did not determine that the Companies should use any specific method in future determinations of need in CPCN proceedings nor that the Companies' findings regarding the reserve margin are absolute.

Q. Who established the minimum reserve capacity requirements used in the Companies' application?

A. The Companies established the reserve capacity requirements.[50] TVA is the Companies' reliability coordinator, but it does not establish reserve capacity requirements, nor has TVA

[48] Case No. 2022-00314, *Application of EKPC for a CPCN for the Construction of Transmission Facilities in Madison County*, Final Order at 7 (Ky. PSC Feb. 23, 2023).

[49] Case No. 2011-00375, *Joint Application of LG&E-KU for CPCN for the Construction of a Combined Cycle Combustion Turbine at Cane Run*, Final Order at 3, 6, 20 (Ky. PSC May 3, 2012). The Commission took a similar approach when approving Big Rivers' conversion of Green Station to natural gas, finding that the conversion was necessary to satisfy a capacity shortfall. Case No. 2021-00079, *Application of Big Rivers Electric Co. for a CPCN for the Conversion of the Green Station Units to Natural Gas-Fired Units* Final Order at 11-12 (Ky. PSC June 11, 2021).

[50] Retirement Assessment at 17. *See also* LGE & KU Response to SC Second Data Request Q15(e).

"informed LG&E/KU of any resource adequacy concerns related to the current system or the proposed unit retirements and resource additions."[51]

Q. Will the Companies' proposed replacement portfolio maintain the minimum reserve capacity requirement established by the Companies for their system?

A. Yes, as discussed in Section III.B above.

D. SB4 Section 2 (2)(b): Will the retirement harm the utility's ratepayers by causing the utility to incur any net incremental costs that could have been avoided by continuing to operate the electric generating units?

Q. How is the no harm to utility ratepayers standard read by the Companies?

A. The Companies interpret this standard to mean that the Companies may retire units if it can show that a replacement resource portfolio results in a lower present value revenue requirement than the current resource portfolio. This is the standard that has been applied in CPCN cases, except that currently the utility bears the burden of proof that its proposed resource portfolio represents a prudent investment. SB4 modifies that standard by requiring the utility to overcome the rebuttable presumption against retiring a fossil fuel fired electric generating unit. If this interpretation is correct, then the modification to past practice is relatively minor and this standard can be met by strengthening the prudency test in CPCN cases to include a clear demonstration that it would not be cost-effective to avoid the retirements.

Q. Have you reached a conclusion as to whether the Companies' proposed portfolio in the CPCN application is prudent?

A. No, that is beyond the scope of my testimony.

[51] LGE & KU Response to JI Fourth Data Request Q6.

Q. Is there another potential interpretation of the no harm to utility ratepayers standard?

A. Yes. As the plain language of this section does not reference the new electric generating capacity, the Commission may interpret this section as requiring an entirely distinct analysis from the CPCN proceeding.

Such an analysis could require the Companies to show that, alongside the Companies' approved resource portfolio (e.g., whatever resources are approved in response to the CPCN application), each unit proposed for retirement would impose a net incremental cost if the Companies continue to operate it in compliance with applicable law. In other words, if it is cost-effective for the Companies to continue to operate one or more units alongside their economically optimal resource portfolio, then they should do so, even if the units are not needed to provide reliability or other services described in SB4.

If this seems unnecessary, I cannot argue. I am not aware of any other utility regulator that is required to consider whether it may be cost-effective to keep a plant in service when it is surplus because it is not required to provide reliability, resilience, or other key utility services. If this Commission interprets the no harm to ratepayers standard in this manner, then it would substantially weaken the Commission's requirement that utilities show an "absence of wasteful duplication" when applying for a CPCN.

If the Companies own a plant that is considered surplus but may have value as a low-cost source of energy, then the Companies could sell it to an independent power producer who can operate it for profit.[52] If there is no market for the surplus plant, that is further evidence that it is not cost-effective for the Companies to keep the plant in service. Good cost

[52] LGE & KU Response to AG & KIUC Joint Fourth Request Q 4-3. The Companies further explain, "The potential economics, issues, risks, and ability to execute such a hypothetical transaction are uncertain but would likely include all of the typical items that would have to be addressed in any sale of a generation unit or unit-specific purchase power agreement including transmission upgrades or expansions."

minimization practices require the Companies to always consider feasible options for selling a surplus plant, either in whole or for salvage value.

The necessity to review the prudence of continued operation of a power plant is driven by the good regulatory practice of avoiding wasteful duplication. Fixed costs and periodic capital investments are always required to continue operating a power plant. As long as decommissioning a plant costs less than the sum of annual fixed costs and periodic capital investments, then a showing that a load-serving utility's preferred resource portfolio is cost-effective is sufficient to demonstrate that keeping a plant in service would result in wasteful duplication and therefore should be retired or, if possible, sold as surplus.

Q. Are you aware of any circumstances where the cost to decommission a plant exceeds the sum of annual fixed costs and periodic capital investments?

A. Yes. In Nova Scotia, there are several physically large hydroelectric systems whose cost of decommissioning is very high. Canada has stringent archaeology and fishery requirements that make it very expensive to decommission some hydroelectric systems. As a result, even though the cost of lifetime extension exceeds the benefits of the energy from those plants, Nova Scotia Power views the benefits of deferring the plant's retirement as justifying further investment.

This example only serves to illustrate my point. Nova Scotia Power's hydroelectric plants can cost hundreds of millions of dollars to decommission, and they are comparatively small, just tens of megawatts in generation capacity. In contrast, most of the units proposed by the Companies for retirement are much larger in generation capacity but would have much smaller decommissioning costs.

Q. Are any of the proposed retirements justified even without the procurement of replacement capacity?

A. Yes. The Companies' analysis of the retirement of Ghent 2 and the small-frame combustion turbines shows that the system does not require additional capacity to replace those units when they are retired.

Q. Please explain how the Companies demonstrate that retiring Ghent 2 would not result in a net cost for customers.

A. The Companies evaluated the retirement of Ghent 2 with no additional (or incremental) replacement resources in Portfolio 5, shown in Table 8 of the Retirement Assessment report.[53] In every sensitivity, the full retirement of Ghent 2 results in net cost savings to customers. In the High Gas/Low CTG sensitivity, retirement results in savings of $7 million,[54] but in that sensitivity there is a preference to maintain Ghent 2 for operation in the non-ozone season. Because every other sensitivity shows a preference to retire Ghent 2 over maintaining it for non-ozone season operations, the Companies' recommendation for full retirement is in the customers interest and maintaining it in operation is likely to result in harm to customers through higher costs.

Q. Please review the retirement process proposed by the Companies for the small-frame combustion turbines.

A. The retirement process proposed by the Companies for Haefling 1-2 and Paddy's Run 12 are described in Mr. Bellar's testimony, as follows:

[53] Retirement Assessment, page 20.

[54] Adding the $32 million savings of switching Ghent 2 to non-ozone season operation to the incremental retirement cost of $25 million results in a net savings of $7 million.

> Although they remain economical with minimal routine maintenance expenses to operate on a limited basis as peaking units (primarily during extreme weather events), they are among the least efficient units in the Companies' fleet and would not be economical to repair and return to service if they encountered any major mechanical issue (i.e., any failure that ordinary maintenance could not address). Nonetheless, because they add value to the system as peaking units, the Companies are seeking approval to retire them upon each unit's experiencing a major mechanical issue rather than authority to retire the units by a certain date.[55] (citations omitted)

In other words, the Companies are proposing to continue to operate these units alongside their economically optimal resource portfolio, even though the units are not needed to provide reliability or other services described in SB4, until a repair cost that exceeds the $130,000 per year of reliability value for Haefling 1-2 or $260,000 per year of reliability value for Paddy's Run 12 is required.[56]

Even these thresholds may be too high. Hypothetically, if a repair cost for one of the Haefling units is $550,000 and it provides five years of expected service life, then it would be less than the added reliability value of $650,000 and the repair would be made under the company's test. However, there is a likelihood that the unit would experience an unanticipated, but ordinary maintenance issue during that five-year period with a cost of over $100,000. In that case, the cumulative cost of the two (or more) repairs could exceed the unit's reliability value.

Q. What do you recommend for the small-frame combustion turbine retirement process?

A. The Companies should modify the economic test for investment in the small-frame combustion turbine units to include an expected value for future below-threshold repair costs. The expected value for future below-threshold repair costs should be calculated using cost data from the past ten years of operating experience. This modification will

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[55] Direct Testimony of Lonnie E. Bellar, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company For Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, at 5 (May 10, 2023) ("Bellar SB4 Direct").

[56] Bellar SB4 Direct at 5, n.9; LG&E/KU Response to Staff Request Q 4.2.

make it unlikely that customers will be harmed by over-investing in maintaining surplus generation units.

Q. Does the Companies' evidence adequately demonstrate that the proposal to replace three proposed coal unit retirements with new resources would not result in a net cost for customers?

A. Yes. The Companies' modeling shows that net costs for customers are lower for retirement of each unit, as summarized in Table 8 of the Retirement Assessment.

- Portfolio 1 shows that replacement of Mill Creek 1-2 with Mill Creek 5 results in net cost savings to customers in every scenario except the High Gas/Low CTG (coal-to-gas price ratio) sensitivity.
- Portfolio 2 shows that replacement of Brown 3 with Brown 12 results in net cost savings to customers in every sensitivity.

The only fuel price conditions under which the Companies' analysis supports keeping some of these coal units in service is the high gas price, low coal-to-gas price ratio sensitivity. Keeping the four coal units in service because of the possibility of higher fuel prices would be placing customers at risk. Consider the Mill Creek replacement portfolio: if instead of the low coal-to-gas price ratio, where customers would save $183 million by keeping Mill Creek 1-2 in service, the ratio remains at historical average or current levels, then the NPV cost to customers would be $257 million (historical average CTG) or even $1,773 million (current CTG) higher if Mill Creek were retained rather than replaced.[57]

In summary, over a wide range of conditions, including the most plausible fuel price forecasts, keeping these units in service *(and not retirement)* is likely to harm the Companies' ratepayers by causing net incremental costs that could have been avoided by retiring the electric generating units.

[57] Retirement Assessment at 20.

Q. Does the decision to retire the plants depend on the implementation of the Good Neighbor Rule?

A. No. The Mill Creek 1 unit cannot continue to operate beyond 2024 due to the Effluent Limitations Guidelines.[58] The Companies state that for Brown Unit 3, the relatively high costs for continued operation are not impacted by the Good Neighbor Plan. The Companies also anticipate that EPA will redesignate Jefferson County as a non-attainment area for ground-level ozone, which will result in requirements for additional air pollution reduction independent of the Good Neighbor Plan.[59]

Q. Would replacement resources have any effect on the opportunity to maintain the surplus coal units in service?

A. Yes, if not entirely impractical, the construction of replacement resources would increase the cost to maintain Mill Creek 1-2 and Brown 3 in service. As noted in Mr. Bellar's testimony, "[b]ased on construction plans and potential electric transmission constraints, the existing units at each site cannot operate at the same time as the proposed NGCC units."[60] Even if feasible, the expense of expanding the sites and transmission capacity to accommodate output from new generation as well as the existing coal facilities would make it even more uneconomical to maintain those units in service.

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[58] LGE & KU Response to Staff Fourth Request Q4.1.

[59] Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Kentucky Coal Association Fourth Set of Data Requests, Question #4 (June 27, 2023).

[60] Bellar Direct, at 4.

E. SB4 Section 2 (3): Is the decision to retire the fossil fuel-fired electric generating unit the result of any financial incentives or benefits offered by any federal agency?

Q. What federal financial incentives or benefits may have affected the Companies' recommendation to retire seven units?

A. I do not believe the Companies' proposed retirements are the result of any financial incentives or benefits offered by any federal agency. While it is true that the Inflation Reduction Act ("IRA") includes federal tax credits that did affect the proposed owned solar and battery storage projects and *may have affected* the proposed solar PPAs, removing those direct effects from the Companies' Retirement Assessment would be unlikely to affect the finding that the seven units should be retired. Furthermore, the Companies "previewed" their retirement proposals before the IRA was passed. Thus, even a portfolio lacking in IRA incentives would retire the units.

The Commission may also want to consider other financial impacts of the proposed retirements in the public interest. If approved, the cost of state tax breaks will be reduced as will the financial impacts of air pollution on people living in Kentucky and other states.

Q. Please explain how you determined that removing the effects of the IRA from the Companies' Retirement Assessment would be unlikely to affect the finding that the seven units should be retired.

A. With respect to the proposed owned projects, the Companies have identified that the nominal benefit of the tax benefit is a $157 million reduction in the revenue requirement for the owned solar projects and a $75.8 million reduction in the revenue requirement for the battery storage project.[61]

During the RFP process, the Companies provided respondents with the opportunity to modify their proposal as a result of the IRA. Although five respondents made

[61] LGE & KU Response to Staff Initial Q47.

modifications, the Companies did not pursue any of those five revised offers.[62] Since none of the selected bids made modifications, it is not possible to infer what, if any, effect the IRA had on those bids based on the modification opportunity. The Companies correctly note that it is not possible to know to what extent any offer reflected a partial or full pass-through of IRA benefits associated with the four solar PPAs.[63] Accordingly, it is impossible to quantify the effects of IRA tax credits or other federal benefits on the pricing reflected in the six solar PPAs.

Furthermore, it is not reasonable to assume that the solar PTC revenue requirement impact estimated for the Companies' owned solar projects would be the same for the solar PPAs. I am not an expert in tax law, but it is my understanding that accounting rules for federal taxes are significantly different for electric utilities than for independent power producers. Studies show that the use of federal tax benefits to finance renewable energy projects does not necessarily result in a dollar-for-dollar reduction in project cost to the ultimate customer. For example, tax equity is estimated to earn a higher return than debt, which means that a dollar in federal tax credit benefit finances less capital than a dollar paid towards debt interest.[64] The design of the federal tax benefit also affects how efficiently it incentivizes investment.[65] One of the main critiques of tax credit requirements is that they

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[62] LGE & KU Response to Staff Initial Q69.

[63] LGE & KU Response to Joint Intervenors Third Request Q9(a), LGE & KU Response to Joint Intervenors Fourth Request Q9(b).

[64] Mark Bolinger, *An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives,* Lawrence Berkeley National Laboratory LBNL-6610E (April. 2014), https://eta-publications.lbl.gov/sites/default/files/lbnl-6610e.pdf.

[65] Joseph E. Aldy et al., *Investment versus Output Subsidies: Implications of Alternative Incentives for Wind Energy*, Journal of the Association of Environmental and Resource Economists (July 2023), https://www.journals.uchicago.edu/doi/epdf/10.1086/723142.

are not refundable or always transferable, resulting in limitations on the benefits available to each project.[66]

Even though the IRA shifts federal tax benefits towards more direct, flexible accounting methods (transferability and refundability), past experience suggests that intermediaries in the project financing process will capture an unknowable portion of the nominal PTC benefit.

Q. How does the Companies' modeling analysis show that the retirement decision would be unchanged even after deducting the value of federal incentives for solar projects?

A. As shown in Table 8 of the Retirement Assessment, a portfolio (#5) with all proposed retirement units excluded and no solar or battery resources added is economically advantageous to retire in all but one fuel price scenario, the high gas price, low coal-to-gas price ratio sensitivity discussed in Section III.D.

Furthermore, if the $157 million federal tax benefit associated with the owned solar projects is removed from the cumulative benefits of the portfolio that includes solar (#6), then the portfolio is still a net benefit to customers. Similarly, if the additional $75.8 million federal tax benefit associated with the owned battery storage project is also removed from the portfolio that includes owned solar and owned battery storage (#7), the portfolio is still a net benefit to the customers.

If one deducts the $233 million in federal tax benefit associated with the owned projects from the $745 million cumulative benefit of the proposed CPCN portfolio (#8), the net benefit is about $512 million. It is impossible to know if the solar PPAs include $512

[66] Bidisha Bhattacharyya, *Renewable Energy Tax Credits: The Case for Refundability*, Center for American Progress (May 28, 2020), https://www.americanprogress.org/wp-content/uploads/sites/2/2020/05/Refundable-Energy-Tax-Credits.pdf.

million or more in federal tax benefits but, given the inefficiency in delivery of tax benefits, that seems unlikely.

Q. How have the Companies "previewed" retirement decisions for these units?

A. In their last rate case, the Companies revised the depreciation dates for several units. As proposed by the Companies in that 2020 rate case, the Brown Unit 3 depreciation schedule was adjusted from the retirement year 2035 to 2028.[67] At that time, the Companies also reasoned that Mill Creek 1 would be economical to retire by the end of 2024, and if an SCR investment were needed at Mill Creek 2, it would be cost-effective to retire that unit by 2028.[68]

These retirement timelines were also previewed in the Companies' 2021 Integrated Resource Plan proceeding. The Companies' 2021 IRP included a 2024 retirement expectation for Mill Creek 1 and 2028 retirement expectations for Mill Creek 2 and Brown Unit 3.[69] Analyses supporting the economic retirement of these units on the now-proposed timelines are not new and demonstrate that the federal tax incentives included in the IRA are not material to the retirement decision.

Q. Are there any other government incentives that impact the economics of the retirement decision?

A. Yes, there are several tax benefits that incentivize the use of coal by the Companies. Fuel and tax costs are reduced by a total of $33.3 million *per year* due to sales and use tax

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[67] *E.g.*, Direct Testimony of Lonnie Bellar, *In re Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Adjustment of Rates*, Case Nos. 2020-00349 and 2020-00350, at 11 ("While the projected retirement dates of Mill Creek Units 1 and 2 are largely being driven by environmental regulations, the rationale behind updating the remaining economic life of Brown Unit 3 is largely economic. . . operation of Brown Unit 3 through 2035 is not economic, and 2028 is a more reasonable date given the potential to avoid major maintenance and lower overall revenue requirements with replacement generation by 2028."), https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp% 40lge-ku.com/11252020084757/10-KU_Testimony_1of4%28Thompson_Blake_Bellar_Sinclair_Wolfe_Saunders%29.pdf.

[68] *Id*. at 10–11.

[69] Companies' Joint 2021 Integrated Resource Plan, Vol. I at 5-17 (pdf 23), https://psc ky.gov/pscecf/2021-00393/rick.lovekamp%40lge-ku.com/10192021013101/3-LGE_KU_2021_IRP-Volume_I.pdf.

exemptions and tax credits for the purchase of coal for the Trimble County 2 plant.[70] In present value terms, twenty years of those tax benefits are worth more than $360 million.

In addition to benefits to the Companies, the mining companies also benefit from state coal severance tax benefit[71] and federal excess depletion tax benefit.[72] As with the solar PPAs, the Companies state that whether coal prices are reduced by the state and federal tax benefits is beyond their "control and knowledge."[73]

Q. Are there any other consumer benefits from the retirement decision that are not explicitly considered in the Companies' analysis?

A. Yes. The EPA's Good Neighbor Rule represents a determination that there are real and consequential health impacts from the pollution emitted by those units that would otherwise need to install pollution control equipment. The acute impacts of the recent Canadian wildfires provided many people in Kentucky with an unwelcome reminder of how air pollution can be transported from miles away and have a direct impact on our health and daily lives.

While the impacts of the pollution from the coal units proposed for retirement are obviously not as severe, they are more persistent. The cumulative effect of many years of exposure to air pollution has been and continues to be injurious to people across many states. While the financial effects of increased health care and lost economic productivity are not measured in the Companies' filing, they should be weighed by the Commission as it considers the broader public interest.

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[70] LGE & KU Response to Joint Intervenors Third Q9(b)(i), (iii).

[71] The statewide benefit to mining companies is forecast to be $5.5 million in 2024. Office of the State Budget Director, *Tax Expenditure Analysis, Fiscal Years 2022-2024,* at 163 (Nov. 2021), https://osbd ky.gov/Publications/Documents/Special%20Reports/Tax%20Expentiture%20Report%2022-24.pdf

[72] Benefit to Kentucky mining companies is unknown. Green Scissors, https://greenscissors.com/program/excess-of-percentage-over-cost-depletion-other-fuels/.

[73] LGE & KU Response to Joint Intervenors Third Data Request Q9(b)(i) through (c).

IV. REVIEW OF SB4 REBUTTABLE PRESUMPTION REQUIREMENTS FOR THE GENERATION REPLACEMENT PROPOSED BY WITNESS ANDREW LEVITT

Q: Please summarize your understanding of the testimony that Mr. Andrew Levitt is filing.

A: I understand that Mr. Levitt is filing testimony that indicates that if the Companies joined PJM, it would reduce and delay the need for new capacity and result in substantial resource cost savings for the Companies' customers. In my opinion, it is reasonable for the Commission to consider whether a combination of the Companies' proposed retirements with membership in PJM would fully or partially address the Companies' resource needs.

The purpose of this section of my testimony is to provide the Commission with an opinion regarding the compliance of this alternative with SB4.

A. SB4 Section 2 (2)(a)(1): Is the new electric generating capacity dispatchable by the utility or independent system operator?

Q. Does energy from PJM meet your suggested definition of dispatchable electric generating capacity?

A. Yes. As I suggested in Section III.A, a good definition for dispatchable electric generating capacity resource is a unit capable of following dispatch instructions between economic minimum and economic maximum when (i) the unit is physically capable of producing electricity and (ii) the unit's power source is available. If the Companies joined the independent system operator PJM, then PJM would take responsibility for dispatching the Companies' assets and would serve the Companies' load with power dispatched from available electric generating capacity.

Thus, any electric generating capacity that is used to serve the Companies' load is, by definition, dispatchable by the independent system operator.

B. SB4 Section 2 (2)(a)(2): Will the new electric generating capacity maintain or improve the reliability and resilience of the electric transmission grid?

1. Reliability Requirement

Q. Would energy and capacity managed by PJM meet or exceed the Companies' reliability standard?

A. Yes, from a LOLE perspective. As discussed in Section III.B, the Companies' economic reserve margin method results in a LOLE of 3.57 days in 10 years for the proposed resource portfolio. My understanding of Mr. Andrew Levitt's testimony is that he expects that if the Companies joined PJM, the reliability of service would meet a LOLE standard of 1-day-in-10-years, which is equivalent to the Companies' maximum reliability standard. From a LOLE perspective, joining PJM could result in higher reliability.

Mr. Levitt's testimony provides some discussion of PJM's intention to shift from an annual to a seasonal reserve margin standard. As I discussed in Section III.B, measurements of reliability using a reserve margin and forecast LOLE provide an incomplete and perhaps even misleading indication of system reliability. If the Commission were to direct the Companies to pursue PJM membership as an alternative to some of the proposed resource investments, it is reasonable to anticipate that PJM's reliability standards and resource adequacy methods may change in the near future, and the costs to the Companies to meet those standards could shift somewhat.

Nonetheless, as long as future PJM standards are reasonable and reflect a similar level of system reliability to that which the Commission would expect the Companies to supply on their own, then I would anticipate that obtaining reliability through PJM should be no more costly than self-supply, and quite likely less costly.

For example, my colleagues at Grid Strategies recently analyzed nine years of historical demand, renewable output, and correlated outage data for the Eastern U.S. and found that capacity needs are reduced by more than 18% if differences in the timing of regional peak demand are recognized.[74] This analysis indicates that it is unreasonably costly for the Companies to acquire sufficient capacity to fully meet their reliability requirements when the alternative is to rely on imports to enhance system reliability.

The opportunity to rely on imports to enhance system reliability is particularly relevant to the Companies, who are not only adjacent to the PJM and MISO RTOs (whether or not they actually join), but can also exchange power with TVA, which serves as the Reliability Coordinator for the Companies. The regions served by these systems exhibit diversity in weather and other drivers of load that ensures those regions do not experience coincident peaks. For example, during Winter Storm Elliott, the Companies imported power from PJM, TVA, and MISO as the storm travelled east.

Taking this opportunity to the next level, the Companies are in the enviable position of being able to consider both PJM and MISO membership options and determine which is most beneficial to their customers.

2. Resilience Requirement

Q. Would energy and capacity managed by PJM meet or exceed the Companies' current level of resilience?

A. With respect to the resilience metrics discussed in the Retirement Assessment (start-up times, ramp rates, and the range of dispatchable capacity), it is my understanding that PJM's existing resources would continue to offer the same level of performance as they do

[74] Michael Goggin et al., *Quantifying A Minimum Interregional Transfer Capability Requirement*, Grid Strategies, at 5 (May 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf.

now, which is sufficient to meet its members' requirements. I am uncertain how PJM system performance could be compared to the performance of individual units.

With respect to the five resilience traits in the NARUC report that are applicable to non-DERs, membership in PJM could improve upon the retired resources, as follows:

1. **Dispatchability**: Due to the aggregation of many resources across a large load, dispatch by PJM to serve the Companies' system load would be sufficient to cover a broader range of load requirements than the Companies' system in isolation.
2. **Fuel Security**: It is my general understanding that the PJM system has greater fuel diversity than either the Companies' existing or proposed system due to substantial solar, wind, and nuclear resources.
3. **Quick Ramping**: For the same reasons as discussed for dispatchability, PJM's effective ramp rate to meet the Companies' system load would be faster than for the resources proposed for retirement.
4. **Grid Services**: Further analysis of voltage support and other ancillary services would need to be conducted to verify that the proposed retirements, along with membership in PJM, would maintain or improve upon the Companies' current resilience. If the Commission determines that the Companies should investigate membership in an RTO as an alternative to some of the replacement resources, it is reasonable to anticipate that there would be costs associated with maintaining grid services. Those costs could involve transmission upgrades, grid-enhancing technologies, or some of the Companies' proposed generation capacity resource investments, potentially including additional battery storage units.
5. **Decentralization**: Membership in PJM would have mixed impacts on decentralization. On the one hand, power would be delivered over the several transmission paths that directly or indirectly link the Companies with PJM, providing some further diversification of resource delivery, but up to the limit of the number

and capacity of transmission lines. On the other hand, diversification through the location of new solar units in areas that do not currently supply power to the grid and a DER deployment strategy, including battery storage, would more directly decentralize the Companies' resources.

In summary, I believe that it is likely that membership in PJM would meet or exceed the Companies' current level of resilience, but it is likely that the Companies would need to make different investments to manage that transition as compared to the CPCN application. I have not reviewed the Companies' studies to determine whether they have already studied RTO membership options and presented evidence on the cost-effectiveness of membership.

C. SB4 Section 2 (2)(a)(3): Will the new electric generating capacity maintain the minimum reserve capacity requirement established by the utility's reliability coordinator?

Q. Who would establish the minimum reserve capacity requirements if the Companies' joined PJM?

A. PJM.

Q. Would membership in PJM maintain or improve upon the minimum reserve capacity requirement currently used for the Companies' systems?

A. Yes, as discussed in Section IV.B above.

D. SB4 Section 2 (2)(b): Will the retirement harm the utility's ratepayers by causing the utility to incur any net incremental costs that could have been avoided by continuing to operate the electric generating units?

Q: If the Companies join PJM, would there be any net incremental costs that could be avoided by continuing to operate the electric generating units?

A: No. As the Companies explain, if they do not retire any of the proposed electric generating units, they will seek to minimize costs to their customers, possibly by "issuing an RFP for the sale of the unit or power from the unit to a third party."[75] With the exception of the temporary continued operation of the small-frame combustion turbine units, the Companies do not anticipate that any of the units proposed for retirement can avoid net incremental costs beyond their proposed retirement dates.

E. SB4 Section 2 (3): Is the decision to retire the fossil fuel-fired electric generating unit the result of any financial incentives or benefits offered by any federal agency?

Q. Would a decision by the Companies to join PJM be the result of federal incentives?

A. It is impossible to analyze this question quantitatively due to the complexity of the PJM market, but I believe it is unlikely. While the relative share of resources that have benefited from federal incentives on the PJM system is larger than the Companies' proposed resource portfolio, there are two additional challenges to analyzing those resources.

First, the resources on the PJM system have benefitted from a wider range of federal incentives. For example, joining PJM would mean relying, in part, on existing nuclear units. Nuclear power has and continues to benefit from a number of federal tax incentives

[75] Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Third Data Requests of the Attorney General and Kentucky Industrial Utilities Customers, Inc., Question 3 (July 7, 2023) ("LGE & KU Response to AG & KIUC Joint Fourth Request Q"). The Companies further explain, "The potential economics, issues, risks, and ability to execute such a hypothetical transaction are uncertain but would likely include all of the typical items that would have to be addressed in any sale of a generation unit or unit-specific purchase power agreement including transmission upgrades or expansions."

and financially advantageous benefits relating to the management of waste and the financial risks associated with major accidents. There are also coal units on the PJM system that likely continue to benefit from federal incentives or benefits, such as low-interest debt issued for coal units owned by rural electric cooperatives.

Second, federal incentives for renewable energy resources on the PJM system are comingled with the financial impacts of state policies such as renewable energy portfolio standards. It would be difficult or impossible to distinguish between the pricing effects of combined federal and state incentives that have affected the resource mix on the PJM system.

Fundamentally, when considering the option to rely on the PJM market for the supply of energy (and to commit the Companies' resources to participate in that market), it is difficult to imagine a process by which the Commission disentangles the many factors that result in market prices for energy and capacity. Open markets benefit participants by aggregating costs and supply constraints into clear pricing signals. An attempt to quantify the cumulative effect of all federal financial incentives and benefits on PJM market prices is likely to be an exercise in poorly informed speculation.

Q. Is this the end of your testimony?

A. Yes.

VERIFICATION

The undersigned, John D. Wilson, being first duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief, after reasonable inquiry.

Subscribed and sworn to before me by John D Wilson this 12 day of July, 2023.

BEN LUCKEY
Notary Public - State at Large
Kentucky
My Commission Expires May 24, 2025
Notary ID KYNP30288

Notary Public

My commission expires: May 24, 2025

John D. Wilson – Résumé

Exhibit JDW-1

JOHN D. WILSON

Vice President
Grid Strategies, LLC

SUMMARY OF PROFESSIONAL EXPERIENCE

2023–Present **Vice President, Grid Strategies, LLC**. Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric utility prudence, cost allocation and rate design. Designs and evaluates electrification and energy efficiency programs for electric utilities, including cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses resource planning and procurement strategies for regulated and competitive markets.

2019–23 **Research Director, Resource Insight, Inc.** Same services as above.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Directed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony to utility regulators. Directed litigation activities, including support of expert witnesses. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air quality, including ozone, air toxics, and other industrial, utility, and transportation pollutants. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for assessments of environmental and resource issues in the Rio Grande / Rio Bravo basin and the Greater Houston region. Coordinated and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

PUBLICATIONS

"Urban Areas," with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

"Quality of Life and Comparative Risk in Houston," with Janet E. Kohlhase and Sabrina Strawn, *Urban Ecosystems*, Vol. 3, Issue 2, July 1999.

"Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs," with Tom Franks and J. Richard Hornby, *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings*, August 2010.

"Monopsony Behavior in the Power Generation Market," with Mike O'Boyle and Ron Lehr, *Electricity Journal*, August-September 2020.

REPORTS

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"Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters," Galveston Houston Association for Smog Prevention, February 2004.

"Reducing Air Pollution from Houston-Area School Buses," Galveston Houston Association for Smog Prevention, March 2004.

"Who's Counting: The Systematic Underreporting of Toxic Air Emissions," Environmental Integrity Project and Galveston Houston Association for Smog Prevention, June 2004.

"Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk," Galveston Houston Association for Smog Prevention, October 2004.

"Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar," Galveston Houston Association for Smog Prevention, January 2006.

"Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control," Galveston Houston Association for Smog Prevention, June 2006.

"Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard," Southern Alliance for Clean Energy, February 2008.

"Cornerstones: Building a Secure Foundation for North Carolina's Energy Future," Southern Alliance for Clean Energy, May 2008.

"Yes We Can: Southern Solutions for a National Renewable Energy Standard," Southern Alliance for Clean Energy, February 2009.

"Green in the Grid: Renewable Electricity Opportunities in the Southeast United States," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Local Clean Power," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

"Recommendations for Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development," Southern Alliance for Clean Energy, March 2011.

"Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study," Southern Alliance for Clean Energy, November 2012.

"Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast," Southern Alliance for Clean Energy, November 2014.

"Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance," Southern Alliance for Clean Energy, July 2015.

"Analysis of Solar Capacity Equivalent Values for Duke Energy Carolinas and Duke Energy Progress Systems," prepared for and filed by Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club in North Carolina NCUC Docket No. E-100, Sub 147, February 17, 2017.

"Seasonal Electric Demand in the Southeastern United States," Southern Alliance for Clean Energy, March 2017.

"Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System," Southern Alliance for Clean Energy, March 2017.

"Solar in the Southeast, 2017 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, February 2018.

"Energy Efficiency in the Southeast, 2018 Annual Report," with Forest Bradley-Wright, Southern Alliance for Clean Energy, December 2018.

"Solar in the Southeast, 2018 Annual Report," with Bryan Jacob, Southern Alliance for Clean Energy, April 2018.

"Tracking Decarbonization in the Southeast, 2019 Generation and CO_2 Emissions Report," with Heather Pohnan and Maggie Shober, Southern Alliance for Clean Energy, August 2019.

"Seasonal Electric Demand in the Southeastern United States," with Maggie Shober, Southern Alliance for Clean Energy, April 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," with Mike O'Boyle, Ron Lehr, and Mark Detsky, Energy Innovation Policy & Technology LLC and Southern Alliance for Clean Energy, April 2020.

"Monopsony Behavior in the Power Generation Market," *The Electricity Journal* 33, with Mike O'Boyle and Ron Lehr (2020).

"Municipal Coal in Ohio: Implications of PJM's Behind-the-Meter Generation," with Paul Chernick and James Harvey, April 2020.

"Review of Nova Scotia Power's 2020 Integrated Resource Plan," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M08059, with Paul Chernick, January 2021.

"Implementing All-Source Procurement in the Carolinas," prepared for Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League and Upstate Forever, for submission in NCUC Docket E-100, Sub 165, and SCPSC Dockets 2019-224-E and 2019-225-E, February 2021.

"Intelligent Feeder Project: Comments on Nova Scotia Power's Final Report," prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M09984, June 2021.

"MGCC Pricing Formula for PG&E's Day-Ahead Hourly Real Time Pricing (DAHRTP) Rates," joint report prepared by PG&E, Small Business Utility Advocates, CPUC Public

Advocates Office, California Large Energy Consumers Association, and Enel X, CPUC Dockets A.20-10-011 and A.19-11-019, March 2022.

SELECTED PRESENTATIONS

"Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

"Energy Efficiency: Regulating Cost-Effectiveness," Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

"Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Indiana State Bar Association, Utility Law Section, Virtual Fall Seminar, September 2020.

"Resource Adequacy, Reserve Margin, & Seasonal Planning," 2022 Georgia IRP Training and Roundtable Series, February 2022.

"Six Lessons from the PG&E Real Time Pricing Rate Proceeding," 45th Peak Load Management Alliance Conference, April 2022.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

Nova Scotia UARB Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

Georgia PSC Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

California PUC Docket A.19-11-019, direct, reply, responsive, and reply to responsive testimony with Paul Chernick in Pacific Gas & Electric's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate design, including customer charges, demand charges, real time pricing tariffs, TOU differentials and periods.

Nova Scotia UARB Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of fuel contract costs. Scope of study on dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

2021 **California PUC** Docket R.20-11-003, direct and reply testimony on rulemaking to ensure reliable electric service in the event of an extreme weather event on behalf of the Small Business Utility Advocates. Modifications to Critical Peak Pricing programs and Time of Use periods. Modifications to load management programs.

Nova Scotia UARB Matter No. M09898, direct testimony on Nova Scotia Power's Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Effect of delays in power contract. Unit modeling assumptions. Variable capital costs. Application of Time-Varying Pricing.

Nova Scotia UARB Matter No. M09920, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2021 on behalf of the Nova Scotia Consumer Advocate. Cost minimization. Project contingency. Economic analysis model. Analysis of specific projects.

Nova Scotia UARB Matter No. M09777, direct testimony with Paul Chernick on Nova Scotia Power's Time-Varying Pricing Tariff Application on behalf of the Nova Scotia Consumer Advocate. Effect of proposed TVP tariffs on load, capacity savings, and energy costs. Recommended CPP tariffs. Treatment of demand charges in TVP tariffs. Implementation and evaluation of TVP tariffs. Lost revenue adjustment mechanism.

South Carolina PSC Docket Nos. 2019-224-E and 2019-225-E, surrebuttal testimony on 2020 Integrated Resource Plans filed by Duke Energy Carolinas and Duke Energy Progress. All-source procurement process. Process for resolution of disputed issues in IRP proceedings.

California PUC Docket A.20-10-011, direct and reply testimony with Paul Chernick in Pacific Gas & Electric's Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing Pilot on behalf of the Small Business Utility Advocates. Rate design for real time pricing tariff. Marketing to small businesses. Evaluation plan.

California PUC Docket R.20-08-020, direct and reply testimony with Paul Chernick in rulemaking to revisit net energy metering (NEM) tariffs on behalf of the Small Business Utility Advocates. Rate design for NEM tariff. Method for analyzing NEM tariff program.

California PUC Docket A.20-10-012, direct testimony with Paul Chernick in Southern California Edison's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate allocation and design, including customer charges and real time pricing tariffs.

Nova Scotia UARB Matter No. M10176, direct testimony on Nova Scotia Power's Smart Grid Nova Scotia Solar Garden Pilot Rate Rider on behalf of the Nova Scotia Consumer Advocate. Addressing risks associated with future cost changes.

Nova Scotia UARB Matter No. M10110, direct testimony on Nova Scotia Power's Wreck Cove hydroelectric project on behalf of the Nova Scotia Consumer Advocate. Reasonableness of project and unresolved issues.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 3) on behalf of the Small Business Utility Advocates. Reasonableness and prudence of remedial and replacement software costs to be included in authorized revenue requirement.

Nova Scotia UARB Matter No. M10197, direct testimony on Nova Scotia Power's Tusket Main Dam Refurbishment Authorization to Overspend application on behalf of the Nova Scotia Consumer Advocate. Whether the project should proceed and whether full cost recovery is justified.

Colorado PUC Proceeding No. 21AL-0317E, answer testimony in Public Service Company of Colorado's 2021 general rate case (phase 1) on behalf of Energy Outreach Colorado. Reasonableness of capital project costs, choice of test year, adjustment to load to reflect effects of pandemic.

2022 **California PUC** Docket A.21-05-017, direct testimony with Paul Chernick in Liberty Utilities Calpeco 2022 general rate case on behalf of the Small Business Utility Advocates. Marginal cost study, revenue allocation, rate design.

Nova Scotia UARB Matter No. M10366, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2022 on behalf of the Nova Scotia Consumer Advocate. Alignment with IRP and new regulation. Cost minimization. Project contingency. Post-project review. Total cost of ownership. Economic analysis model. Decommissioning. Analysis of specific projects.

California PUC Docket A.21-10-010, direct testimony on Pacific Gas and Electric's proposed Electric Vehicle Charge 2 Program on behalf of the Small Business Utility Advocates. Program scale and unit costs. Cost controls. Cost Allocation.

Nova Scotia UARB Matter No. M10400, direct testimony on Nova Scotia Power's Work Management and Scheduling & Dispatch Application on behalf of the Nova Scotia Consumer Advocate. Economic analysis. Additional applications for software. Contingency guidelines. Total cost of ownership.

Massachusetts DPU Docket No. 22-22, direct, surrebuttal and supplemental testimony on Eversource Energy's 2022 Base Distribution Rate Case on behalf of the Cape Light Compact. Allocation of distribution revenue requirement.

Nova Scotia UARB Matter No. M10431, direct testimony on Nova Scotia Power's 2022 General Rate Application on behalf of the Nova Scotia Consumer Advocate. Board directives. Fuel costs. Capital project revenue requirements. Deferral accounts and riders. Cost allocation. Residential customer charge.

2023 **Nova Scotia UARB** Matter No. M10959, direct testimony on Nova Scotia Power's 2023 Application for Annually Adjusted Rates on behalf of the Nova Scotia Consumer Advocate. Seasonal and time-varying rates. Impact of Maritime Link power delivery. Cost of service study updates.

California PUC Docket R.22-07-005, direct testimony on Rulemaking to Advance Demand Flexibility Through Electric Rates. Income-graduated fixed charge: cost categories, rate design, and impacts on electrification, low-income ratepayers, and energy efficiency.

Nova Scotia UARB Matter No. M10960, direct testimony on Eastward Energy's 2023 General Rate Application on behalf of the Nova Scotia Consumer Advocate. System Expansion Investments. Customer connection incentive program. Impacts on electrification programs.

Nova Scotia UARB Matter No. M10416, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of biomass fuel costs. Shortfall in expected customer benefits from Maritime Link transmission project. Regional joint dispatch. Accounting issues related to coal supplies and wind farm tax credits. Impact of demand response and time-varying rates on fuel costs.

Nova Scotia UARB Matter No. M11009, direct testimony on the disposition of the Nova Scotia Power Maritime Link Inc's Holdback. Benefits of Maritime Link, including energy- and capacity-related benefits. Offset of replacement energy costs. Sufficiency of regulatory process to recover customer benefits.

Nova Scotia UARB Matter No. M11017, direct testimony on Nova Scotia Power's Annual Capital Expenditure Plan for 2023 on behalf of the Nova Scotia Consumer Advocate. Capital projects with risk. Reliability investments. Cost minimization practices, including project contingency, total cost of ownership, project delivery model, and post-project reviews. Analysis of specific projects.