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 AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS**	**Kentucky Public Service Commission Case No. 2022-00402**

DIRECT TESTIMONY OF

MICHAEL GOGGIN

ON BEHALF OF

SIERRA CLUB

FILED: JULY 14, 2023

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AFFIDAVIT OF MICHAEL GOGGIN
IN SUPPORT OF DIRECT TESTIMONY ON BEHALF OF SIERRA CLUB

Washington)
D.C.)

Affiant Michael Goggin states the following: The prepared Direct Testimony and associated exhibits filed herewith on Friday, July 14, 2023, constitute the direct testimony of Affiant in the above-captioned case. Affiant states that he would give the answers set forth in his Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

Michael Goggin

SUBSCRIBED, ACKNOWLEDGED, AND SWORN to before me by Michael Goggin this 14 day of July, 2023.

Notary Public

Notary ID No.: ____________________

My Commission expires: 09.14.2023

THOMAS M. DAVIS
NOTARY
Exp. - 09/14/23
PUBLIC
DISTRICT OF COLUMBIA

Exhibits to the Testimony of Michael Goggin

Exhibit No.	Description of Exhibit	Protected Status	Format
MG-1	Michael Goggin Curriculum Vitae	Public	PDF
MG-2	Compiled Discovery Responses	Public	PDF
MG-3	List of Flowgates Used In LG&E and KU AFC, ATC Process	Public	PDF
MG-4	Energy Information Administration Form 930 Datafile for LGE/KU	Public	Excel
MG-5	Goggin et al., *Quantifying a Minimum Interregional Transfer Capability Requirement*	Public	PDF
MG-6	Compiled articles discussed in Footnote 32	Public	PDF
MG-7	*Getting Capacity Right – How Current Methods Overvalue Conventional Power Sources*	Public	PDF
MG-8	Astrape Consulting, *Estimation of the Market Equilibrium and Economically Optimal Resere Margins for the ERCOT Region for 2024*	Public	PDF
MG-9	Brattle Group, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region*	Public	PDF

Table of Contents

DIRECT TESTIMONY OF MICHAEL GOGGIN

Q: Please state your name and job title.

A: My name is Michael Goggin, and I am Vice President at Grid Strategies, LLC, a consulting firm based in the Washington, D.C. area.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of the Sierra Club.

Q: Have you ever testified before state utility commissions or other regulatory bodies?

A: Yes, I have testified before state utility commissions in Arizona, Colorado, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Virginia, Washington, and Wisconsin, as well as before the Federal Energy Regulatory Commission ("FERC").

Q: Please briefly describe your educational and professional background.

A: I have worked on transmission and renewable energy issues for over fifteen years. At Grid Strategies, LLC, I have served as an expert on these topics for a range of clients interested in clean energy for over five years. For the preceding ten years, I was employed by the American Wind Energy Association ("AWEA"), now known as the American Clean Power Association, where I provided technical analysis and advocacy on renewable energy and transmission matters. This included directing the organization's research and analysis team from 2014 to 2018. Prior to that, I was employed at a firm serving as a consultant to the U.S. Department of Energy, and two environmental groups. Over the course of my career, I have co-authored over one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; and published academic articles and conference presentations on renewable energy, transmission, and policy. I have also served as an elected member of the Standards, Planning, and Operating Committees of the North American Electric Reliability Corporation ("NERC"). I hold an undergraduate degree with honors from Harvard University. A copy of my Curriculum Vitae is attached as **Exhibit MG-1**.

Q: What is the purpose of your testimony?

A: My testimony primarily focuses on the Companies' need for generating capacity to meet periods of peak demand. I analyze the Companies' assumptions for the contributions of generation imports, renewable and storage resources, and gas generators towards meeting peak demand, and find that they understate the contributions of imports and of renewable and storage resources, and overstate the contributions of gas generators. I also identify other assumptions that cause the Companies to overstate their need for generating capacity.

Q: Please summarize your testimony.

A: The Companies' analysis overstated the need for the two proposed combined cycle plants, as it did not adequately account for how imports, renewables, battery storage, and existing resources work together to provide reliable power. First, I explain that LGE/KU has historically used power imports to meet peak demand, and that by understating the contribution of imports, their analysis overestimates capacity needs by at least 600 MW. Second, I discuss how the analysis also understates the reliability contributions of renewable and storage resources. Third, the Companies' analysis also overstates the capacity contributions[1] of gas generation by ignoring the risk of correlated outages, like those that led to rolling blackouts during Winter Storm Elliott. Understating the capacity contribution of renewables and storage, and overstating that of gas, also biases the analysis towards the selection of gas resources and away from renewable and storage solutions. Fourth, I explain how other flawed assumptions in the Companies' assumed cost of generation shortages also caused it to significantly overstate the need for additional capacity. Finally, I explain how batteries meet the increasing need for flexible capacity and other reliability services better than relatively inflexible combined cycle generators.

Correcting the above errors indicates that the proposed gas combined cycle generators are not needed. As noted above, a more reasonable import assumption conservatively reduces the need for capacity by 600 MW, and the impact is likely to be 900 MW or even higher. Higher capacity value assumptions for the Companies' planned solar and battery storage resources would reduce the need for capacity by nearly 200 MW, and more if using a higher capacity value for those resources led to more of them being selected in the Companies' economic procurement analyses. More reasonable assumptions for the value of lost load in the Companies' reserve margin analysis would also reduce the need for capacity by roughly 200 MW. Accounting for the impact of gas correlated outages also significantly reduces the capacity value of the 1,242 MW of

[1] Capacity contributions are often measured in capacity value, which is the amount of capacity a resource provides during peak periods divided by its nameplate capacity. This is a measure of accredited capacity towards peak demand and different from capacity factor, which is a measure of energy production. Capacity factor measures the amount of energy actually produced by a resource over a time period divided by the maximum amount it could produce if it operated at full output at all times.

proposed combined cycle generators, likely to below 900 MW based on the Companies' gas fleet performance during Winter Storm Elliott. In sum, correcting those errors reduces the need for capacity by at least 1,000 MW, displacing more than the full capacity value provided by the proposed gas generators.

I. <u>The Companies' Analysis Understates the Capacity Contribution of Imports by at Least 600 MW.</u>

Q: How is the Companies' need for generating capacity affected by the ability to import power during periods of peak demand?

A: Imports of power meet electricity demand, and thus offset the Companies' need for increased generation supply. Mostly due to the localized nature of weather events and regional differences in climate, different utilities experience peak demand at different times. During periods of peak demand, for example, this allows utilities to import from other utilities that are not experiencing peak demand at that same point in time. For example, PJM and MISO tend to experience their highest demand in the summer, while the Companies' greatest need is often in the winter, allowing them to share surplus power. There is also diversity in the times at which different utilities experience weather-related reductions to generation supply from renewable and conventional resources, further increasing the value of imports. I agree with the conclusion of the testimony submitted by Mr. Levitt in this docket that joining an RTO, and particularly PJM, is the most effective way to access that geographic diversity and reduce the Companies' need for generating capacity. Even absent joining an RTO, the Companies have strong transmission access to the PJM, Midcontinent Independent System Operator (MISO), and Tennessee Valley Authority (TVA) grid operators today, allowing them to reduce their need for generating capacity using imports—as they have historically.

A. <u>The Companies' reliability analysis incorrectly assumes little to no transmission capacity to deliver imports.</u>

Q: What did the Companies assume regarding the availability of transmission capacity to deliver imports?

A: The Companies explain that they analyzed:

> daily ATC [Available Transmission Capacity] between the Companies' system and neighboring regions on weekdays during the summer months of 2019 and 2020 and the winter months of 2020 and 2021. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 42% of the time. ATC is modeled in SERVM [Strategic Energy Risk Valuation Model, a model used in the Companies' reliability analysis] based on this distribution… During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM [Equivalent Load Duration Curve Model, another model used in the Companies' reliability analysis] is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time.[2]

Because the Companies' reliability analysis randomly assigns these zero import hours across peak demand hours, the effect of this assumption is to give imports essentially zero credit towards meeting peak needs. For example, if demand is comparably high in the top three peak hours, the hour in which imports are assumed to be zero will primarily set the need for capacity as it now has the highest net demand by far, while the two hours in which imports are assumed to be 500 MW will receive little to no weight for setting the capacity need. As I illustrate using eight years of historical data in Section C below, imports have never been zero during the highest peak demand hours, contrary to the Companies' assumptions in these two models.

Q: Does the Companies' methodology accurately measure total transmission capacity during peak periods?

A: No, for several reasons. First, Available Transmission Capacity is only a portion of Total Transmission Capacity, which is a better metric of the transmission available for imports.

[2] Dir. Test. of Stuart A. Wilson, Exh. SAW-1, 2022 RFP Minimum Reserve Margin Analysis, D15-16.

Other components of Total Transmission Capacity include actual scheduled transmission reservations and the capacity benefit margin.[3] The capacity benefit margin exists precisely for the reason of enabling imports during peak demand periods,[4] but transmission capacity reserved for the capacity benefit margin is not included in ATC. The Companies hold significant capacity benefit margin on transmission ties, which is capacity held in case it is needed to meet peak demand, so this capacity should count towards meeting peak demand but is not reflected in ATC.[5] Transmission reservations, which is transmission capacity that is reserved for a transaction, are also not included in ATC. This would include scheduled imports used to meet peak demand. Transmission reservations that are not fully used, which typically accounts for a significant share of transmission capacity, are also freed up for non-firm imports. In addition, retiring fossil generators' transmission reservations will also be freed up. Given the significant planned retirements on and around the Companies' system, and because fossil generators typically reserve enough transmission capacity to cover their full nameplate capacity, this could significantly increase transmission capacity for on-peak imports going forward.

Second, the Companies' analysis only looks at transmission capacity that is available for all hours in a day, which may miss transmission capacity that is available during peak hours but not other hours in the day. Relatedly, the Companies' analysis

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[3] LGE & KU, *Available Transfer Capability Implementation Document (ATCID)* (December 15, 2021), https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LGE-KU_ATCID_effective_12-15-2021.pdf

[4] See PJM, *2022 PJM Reserve Requirement Study: PJM Resource Adequacy Planning*, 33 (2022), https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx (PJM's explanation of how ATC does not include capacity reserved for the Capacity Benefit Margin).

[5] *CBM values for flowgates used in the LG&E and KU AFC/ATC calculations* (June 8, 2023), https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/FG_CBM_Effective_06-08-2023.pdf.

looks at ATC for all weekdays during certain winter and summer months, without focusing on the peak demand days in those months.

In Section C below, I analyze eight years of actual import data for the Companies' peak demand hours, and find that the Companies are large net importers during all of the highest peak demand hours, with imports reducing capacity needs by at least 600 MW.

B. <u>During the Companies' time of need, there is available generation capacity in MISO, PJM, and TVA.</u>

Q: What assumptions do the Companies make about the availability of resources in neighboring grid operating areas?

A: The Companies' reliability analysis also understates the availability of generating resources in neighboring regions to provide import supply during peak periods. While this assumption may not have a major impact on the Companies' reliability analysis because of the flawed assumption that there is zero transmission capacity for imports during peak hours, it is important to correct this misconception. The Companies' assumptions about the supply and demand of capacity and the target reserve margins in neighboring grid operating zones are outlined at pages D11-D12 in Exhibit SAW-1, and in Witness Wilson's related workpapers.[6]

Q: Are there flaws in these assumptions?

A: Yes. First, the Companies' analysis only accounted for resources in the immediately adjacent area, which is MISO Indiana and PJM West, even though those areas are strongly tied to the rest of the MISO and PJM footprints and thus can bring in supply

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[6] Dir. Test. of Stuart A. Wilson, Exh. SAW-2 (Public Workpapers), Vol. 6, 20221121_ResourcesforRM.xlsx.

from other areas during times of need.[7] MISO's zonal reserve analysis shows MISO Indiana can rely on imports of 6,952 MW from other parts of MISO.[8] Similarly, the western part of PJM is very strongly interconnected with the rest of the footprint. Western PJM is also a major exporter to the rest of PJM.[9] If there is high local demand, that area will first back down exports on that transmission capacity, and then use its transmission ties to the rest of PJM to import, providing a further cushion of surplus generation. The Companies miss the large diversity benefits within MISO and PJM that help ensure adequate supplies of imports will be available from MISO and PJM, even if the immediately adjacent zones are being similarly affected by high demand during LGE/KU's peaks. There also appears to be a discrepancy between MISO data and the Companies' assumed load in MISO Indiana that further understates available supply. MISO's reserve analysis shows expected load of 18,099 MW in MISO Indiana in 2028,[10] while the Companies assume load will be 20,809 MW.[11]

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[7] LG&E-KU Resp. to Sierra Club First Data Req. 1.5 (provided Mar. 10, 2023) ("For MISO-Indiana, 24,552 MW of the region's generation resources were included to meet its target reserve margin of 18%. For PJM-West, 40,007 MW of the region's generation resources were included to meet its target reserve margin of 14.8%. For TVA, 35,648 MW of the region's generation resources were included to meet its target reserve margin of 17%. These levels were obtained by deactivating existing dispatchable resources in SERVM.").

[8] MISO Energy, Loss of Load Expectation Working Group, *Planning Year 2022-2023 Loss of Load Expectation Study Report* 13 (2022), https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[9] Monitoring Analytics, LLC, *State of Energy Market Support for PJM* 191 (2022), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec3.pdf.

[10] MISO Energy, Loss of Load Expectation Working Group, *Planning Year 2022-2023 Loss of Load Expectation Study Report* 28 (2022), https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[11] Exh. SAW-2 to Dir. Test. of Stuart A. Wilson (Public Workpapers), Vol. 6, 20221121_ResourcesforRM.xlsx.

Q: Are there other flaws in the Companies' assumptions?

A: Yes. Second, the Companies' analysis argues that:

> Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of developing a minimum reserve margin for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 18% (MISO), 14.8% (PJM), and 17% (TVA).[12]

However, NERC's Long-Term Reliability Assessment shows there are currently major capacity surpluses in PJM and TVA, and that those are expected to persist for at least the next decade. NERC projects that in each year over the next decade, PJM will have reserve margins of 35.7-39% after accounting for committed new resources, relative to a target of 14.7%.[13] This reserve margin translates into 53-56 GW of capacity above expected demand, or 31-35 GW of capacity above the reserve margin target. Given the size of this surplus, even if large-scale fossil generator retirements do occur, PJM should have abundant capacity. PJM has had a similarly large capacity surplus for nearly 15 years, adding further confidence that it will persist. PJM maintained large surpluses through the wave of coal plant retirements triggered by the Mercury and Air Toxics Standards nearly a decade ago, despite claims from some parties that it would harm PJM's supply of capacity.

NERC projects that the SERC Central region, which includes TVA and also LGE/KU, will have a reserve margin of 20.1-23.6% across all years in the next decade,

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[12] Dir. Test. of Stuart A. Wilson, Exh. SAW-1, at D12.

[13] NERC, *2022 Long-Term Reliability Assessment* 60 (Dec. 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

relative to a target of 15%.[14] NERC also projects that MISO will have a large capacity surplus if a significant share of planned resources come online.[15] MISO has also recently seen a large influx of new capacity, and its accredited capacity position has significantly improved with the move to a seasonal resource adequacy construct.[16]

Q: Are these regions expecting large additions of generation that will increase exports?

A: Yes. The Companies admit that their analysis does not account for planned resource additions in these neighboring areas.[17] MISO is adding dozens of gigawatts (GW) of wind, which will help complement the Companies' planned solar resources by increasing nighttime and winter imports. This includes wind enabled by the Long-Range Transmission Planning (LRTP) Tranche 1 transmission projects, which are designed to integrate 53 GW of new renewables[18] and are slated to start coming into service as the Companies' claimed need for capacity begins later this decade. The tentative plans for LRTP Tranche 2 projects,[19] slated to move towards approval in the first half of 2024, include large transmission lines to deliver some of that energy to the parts of MISO that directly border Kentucky. MISO and the Southwest Power Pool (SPP) are also

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[14] *Id.* at 66.

[15] *Id.* at 25.

[16] MISO, *Planning Resource Auction: Results for Planning Year 2023-24* (May 19, 2023), https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf.

[17] LG&E-KU Resp. to Joint Intervenors' First Data Req. 1.88b (provided Mar. 10, 2023).

[18] Ethan Howland, *MISO board approves $10.3B transmission plan to support 53 GW of renewables*, Utility Dive (July 26, 2022), https://www.utilitydive.com/news/miso-board-transmission-plan-midcontinent-renewables/628108/.

[19] RTO Insider, *'Conceptual' Tx Planning Map Troubles MISO Members* (December 1, 2022), https://www.rtoinsider.com/31197-conceptual-tx-planning-map-troubles-miso-members/.

developing the Joint Targeted Interconnection Queue projects, which will enable at least 28 GW of additional renewables.[20] MISO wind is accredited with a 40.3% capacity value in winter,[21] confirming these expanded exports will help meet the Companies' winter needs and complement their solar resources. Significant renewable development is also occurring in PJM, with much of the wind expansion occurring in western PJM.[22]

Other transmission expansion will further increase the availability of imports. The Grain Belt Express project is designed to deliver 2,500 MW to PJM's Sullivan substation in Indiana, and another 2,500 MW in Missouri where it will be delivered to Associated Electric Cooperative Incorporated ("AECI") and MISO load. Grain Belt Express has ordered equipment and plans to begin construction next year.[23] This project will deliver a mix of around 6,200 MW of wind and 3,100 MW of solar located in SPP, with the potential for battery capacity additions as well, offering an estimated year-round capacity factor of 74% for the 5,000 MW capacity of the transmission line. It is also proposed to allow bi-directional flows among PJM, MISO, and SPP, providing several GW of transmission capacity to tap into diversity in the timing of their peak needs. The Sullivan substation mostly delivers its power eastward via a direct 765-kiloVolt transmission tie to

[20] Kelley Welf, *MISO, SPP Identify Transmission Upgrades Enabling 28 GW of New Renewables* (March 9, 2022), https://www.renewableenergyworld.com/solar/miso-spp-transmission-study-reveals-28-gw-renewable-energy-potential/.

[21] MISO, *Planning Year 2023-2024 Wind and Solar Capacity Credit Report* (Mar. 2023), https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf.

[22] *See, e.g.*, PJM, *PJM Renewable Energy Projects*, https://mapservices.pjm.com/renewables/.

[23] Dia Kuydendall, *Grain Belt Express Selects Siemens Energy as HVDC Technology Partner*, Grain Belt Express (Jan. 2023), https://grainbeltexpress.com/grain-belt-express-selects-siemens-energy-as-hvdc-technology-partner/.

the Rockport substation, which is directly across the Ohio River from Kentucky and strongly interconnected to the Companies' system via five distinct flowgates.[24]

To the south, TVA is also adding large amounts of new capacity. TVA is adding a 1,450 combined cycle generator at its Cumberland Fossil Plant, and has proposed adding around 1,500 MW of gas capacity at the Kingston Fossil Plant. While they add capacity, however, these plants are likely to place further strain on regional gas supply and delivery capacity, adding to the gas correlated outage risks discussed in Section III below. TVA's IRP also plans adding more than 10,000 MW of solar by 2035, which will also increase the availability of imports to help meet summer peak demand.

Q: Are the Companies' claims about fossil retirements reducing available capacity in neighboring areas a reason for concern?

A: Even if highest projections[25] for retirements are realized, the energy and capacity markets operated by MISO and PJM are inherently self-correcting to prevent that from causing a capacity shortfall. The inherent self-balancing of supply and demand in wholesale energy and capacity markets protects against power plant retirements causing an electricity supply shortfall. In any competitive market, reducing supply below the level of demand causes prices to increase. Higher prices in turn cause some of that supply to reconsider leaving the market, incentivize new supply to enter the market, or even cause demand to decrease, bringing supply and demand back into balance. In some states, utilities and their regulators add an additional layer of protection by guiding resource expansion

[24] *See List of Flowgates Used in LG&E and KU AFC/ATC Process* (June 8, 2023), https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/List_of_Flowgates_Effective_06-08-2023.pdf (attached as Exh. MG-3).

[25] *See, e.g.*, Dir. Test. of Lonnie E. Bellar at 5.

decisions. Moreover, many of the proposed EPA rules include compliance flexibility and/or explicit reliability provisions that allow plants that are truly needed for reliability to continue operating while replacement resources are built. Both PJM and MISO also have processes to review proposed retirements for their impact on reliability, and they can and do take steps including delaying a proposed retirement to address any problems that may arise. PJM also has a "reliability backstop," in which they would conduct an additional capacity procurement after three consecutive auctions that clear below the target reliability requirement.[26]

C. <u>Corrected analysis of how imports reduce the Companies' need for capacity.</u>

Q: Have you conducted your own analysis of the Companies' ability to import power to meet their peak needs?

A: Yes. Given the fundamental flaws in the Companies' analysis of both generating capacity availability in neighboring grid operating areas and the transmission capacity to deliver that generating capacity, I analyzed the Companies' actual imports during historical peak periods over the last eight years. Because it reflects actual imports, this analysis accounts for the availability of both generation supply and transmission capacity to deliver power during the Companies' peak periods. This analysis shows that the Companies have historically imported power during peak periods to meet generation needs. This conclusion is corroborated by data provided by the Companies showing large purchases from PJM, MISO, and TVA during Winter Storm Elliott.[27]

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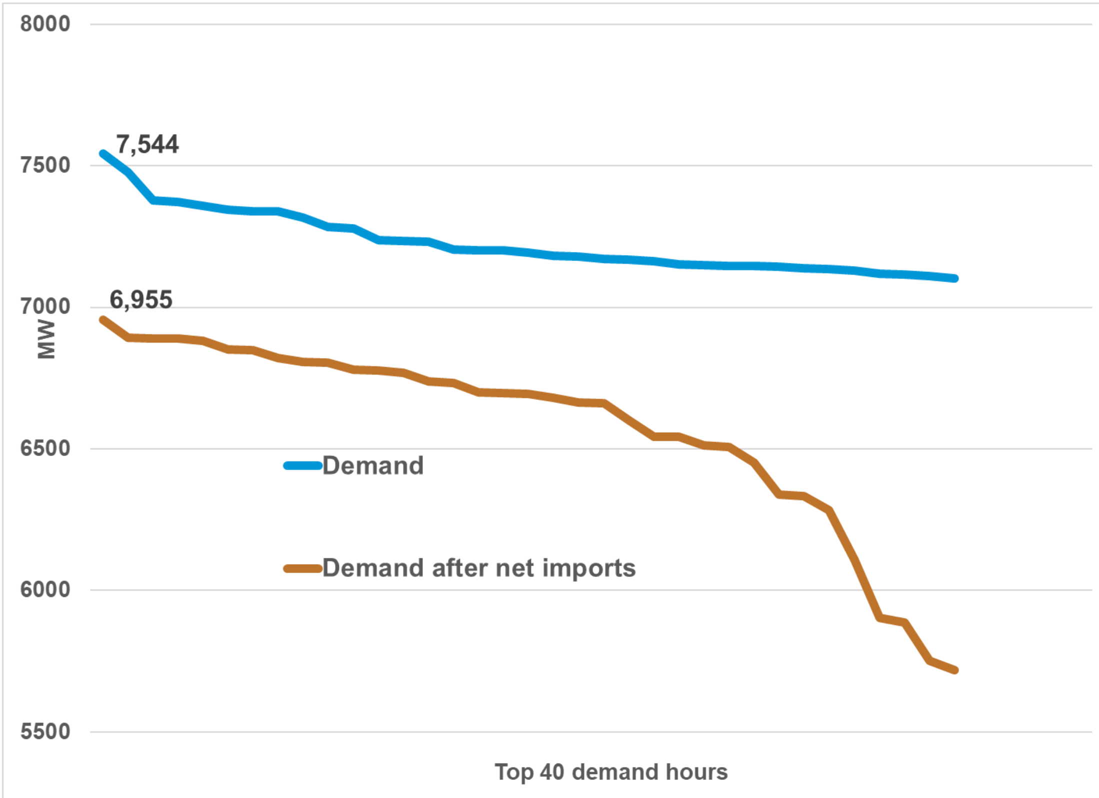
[26] PJM, *PJM Manual 18: PJM Capacity Market* 134 (Feb. 2023), https://www.pjm.com/~/media/documents/manuals/m18.ashx.

[27] LG&E-KU Resp. to Sierra Club First Data Req. 1.19.b (provided Mar. 10, 2023).

Department of Energy (DOE) data[28] show that during all peak demand hours, including winter and summer peak hours, the Companies receive large net imports. Imports often exceed 1,000 MW. Demand and import data for the Companies' top 40 demand hours across the last eight years are shown below, and sorted by the highest demand hours. The bolded results in the top two rows indicate that imports reduced the need for capacity from the 7,544 MW of demand in the top row, to the 6,955 MW of demand after net imports in the second row, or capacity savings of 589 MW (7,544 – 6,955). After subtracting the 1,437 MW of net imports in the highest demand hour, that hour no longer has the greatest need for capacity, so the hour in the second row becomes the hour that sets the need for generating capacity. These results are also shown graphically as a load duration curve following the table. Based on these results, a conservative estimate is that net imports reduce the Companies' need for capacity by around 600 MW.

[28] U.S. Dep't of Energy, Energy Info. Admin., *Form 930 Datafile for LGE/KU*, https://www.eia.gov/electricity/gridmonitor/knownissues/xls/LGEE.xlsx (accessed July 7, 2023) (attached as Exh. MG-4).

Date	**Hour ending**	**Demand**	**Net imports**	**Demand after net imports**
23Dec2022	18	**7,544**	1,437	6,107
23Dec2022	11	7,476	521	**6,955**
23Dec2022	10	7,379	681	6,698
23Dec2022	12	7,373	866	6,507
23Dec2022	20	7,358	907	6,451
23Dec2022	19	7,346	1,014	6,332
23Dec2022	21	7,340	797	6,543
23Dec2022	13	7,339	796	6,543
23Dec2022	17	7,317	1,414	5,903
23Dec2022	22	7,283	943	6,340
23Dec2022	14	7,279	995	6,284
15Jun2022	15	7,236	345	6,891
23Dec2022	15	7,234	1,515	5,719
23Dec2022	16	7,232	1,481	5,751
23Dec2022	9	7,204	693	6,511
16Jun2022	17	7,202	463	6,739
16Jun2022	16	7,201	423	6,778
16Jun2022	15	7,194	460	6,734
15Jun2022	16	7,182	299	6,883
20Jul2022	17	7,178	479	6,699
23Dec2022	23	7,170	1,283	5,887
15Jun2022	17	7,168	278	6,890
16Jun2022	14	7,163	468	6,695
12Aug2021	16	7,153	472	6,681
12Aug2021	15	7,148	488	6,660
16Jun2022	18	7,146	482	6,664
14Jun2022	17	7,145	295	6,850
22Jun2022	15	7,143	363	6,780
06Jul2022	14	7,139	538	6,601
12Aug2021	17	7,135	366	6,769
14Jun2022	16	7,131	283	6,848
15Jun2022	14	7,120	299	6,821
14Jun2022	18	7,115	311	6,804
15Jun2022	18	7,110	303	6,807
11Aug2021	17	7,101	209	6,892
23Dec2022	8	7,101	458	6,643
14Jun2022	15	7,098	307	6,791
20Jul2022	18	7,089	396	6,693
20Jul2022	16	7,086	456	6,630
11Aug2021	15	7,080	216	6,864



Q: Why is this analysis likely conservative?

A: This 600 MW estimate is likely conservative for multiple reasons. First, the Companies were also exporting to some neighbors while importing from others during many of these hours, reducing the net imports shown above. If one excludes exports to only account for gross imports, reflecting that the Companies could likely curtail non-firm exports if needed, the capacity benefit of imports increases modestly to 637 MW. In addition, imports were low during many of these hours because the Companies' own generators were available and operating properly, so they did not need imports. As discussed in more detail below, if the Companies had needed more imports during those hours, market price data indicates additional generation and transmission capacity was available to support a higher level of imports. If one also removes hours in which imports were low because the Companies' generators were providing abundant supply from the table above, the capacity benefit of imports increases to around 900 MW.

By focusing on the single worst hour in which high demand coincided with low imports over the eight-year period, my analysis is more conservative than the probabilistic analysis used by the Companies, which randomly varied imports during peak load hours. My analysis is also more conservative than is needed to meet the one-day-in-10-year Loss Of Load Expectation standard, as my analysis does not allow any loss of load. Allowing enough loss of load to still meet that standard indicates that imports can be credited with 880 MW of capacity value.[29]

Q: As a result, what is your conclusion?

A: Based on these results, 600 MW is a conservative estimate of how much in terms of imports the Companies can rely on during periods of need, while 900 MW is a middle range estimate of the capacity value of imports. In contrast, the Companies' analysis effectively assumed 0 MW of imports were available, based on the assumption that no import transmission capacity was available in 42% of peak hours. Correcting that assumption reduces the Companies' claimed need for capacity by 600-900 MW, which alone negates the need for at least one of the proposed combined cycle generators, and potentially half or more of the capacity provided by the second proposed combined cycle generator. The Companies have relied on imports to meet peak demand over at least the last eight years, and there is no reason to expect that that pattern will not continue.

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[29] This is estimated by calculating the reduction in capacity needs from imports after assuming loss of load is allowed in up to 19 hours (the 1 day in 10 years standard, multiplied by the 8 years covered in the dataset).

Q: Is the Companies' ability to import power during periods of peak need potentially even higher than this?

A: It likely is. The above estimates are conservative because they do not reflect that the Companies could have imported more power if needed, aside from hours during Winter Storm Elliott when the Companies were curtailing firm load. Additional analysis of real-time market prices indicates both additional generation supply and transmission capacity were available during these hours. Locational marginal price data for MISO, PJM, and the Companies' interface with the MISO market[30] show prices in those three areas are almost always comparable during these hours, indicating there is minimal transmission congestion among those areas during the Companies' peak demand hours. Marginal prices are also generally low during the Companies' peak demand hours, indicating imports are available at relatively low cost and more supply would be available if the Companies had a greater need. Specifically, outside of Winter Storm Elliott, prices at the Companies' interface with MISO do not typically exceed $200/MWh during the Companies' peak demand hours, indicating additional supply is available at a reasonable price if the Companies needed to bid for it in the market.

Q: Do imports provide dependable capacity?

A: Yes. The reduction in capacity needs from imports calculated above is based on the highly dependable diversity benefit that results from differences in the timing of peak need across different regions. As noted in the testimony of Mr. Levitt, there is

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[30] Price data for the MISO Indiana hub, the LGE interface with MISO, and the PJM interface with MISO for the relevant peak demand hours was obtained from MISO, *Market Reports*, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Real-Time%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc.

considerable diversity in the timing of peak load between PJM and the Companies. This is mostly driven by the fact that severe weather like extreme heat or cold is only at its most extreme in a relatively small geographic area, as well as the movement of weather systems over time, climatological differences among regions, and time zone differences that affect when consumers are using the most electricity. The data above show the Companies are always net importers during their periods of peak need, which makes sense because when the Companies are experiencing the very worst of a weather event, it is nearly certain that the weather is less extreme in at least some neighboring regions. The Companies are also well-positioned to import from PJM and MISO because those power systems experience peak demand in the summer, while the Companies' analysis indicates they tend to experience their highest need in winter.

I recently analyzed nine years of historical demand, renewable output, and correlated outage data for the Eastern U.S., and found a more than 18% reduction in capacity needs by netting out differences in the timing of when regions experience their peak need.[31] Given that the Companies are located at the nexus of three large power systems (MISO, PJM, and TVA) that in turn stretch from the Dakotas to Virginia and south to the Gulf Coast, they can reliably count on tapping into the large diversity in weather and climate patterns that ensure the entirety of those regions do not experience peak needs at the same time. For example, as Winter Storm Elliott moved eastward out of MISO, the Companies were able to pivot from importing from PJM and TVA to

[31] Michael Goggin, Zach Zimmerman, & Abby Sherman, *Quantifying a Minimum Interregional Transfer Capability Requirement*, Grid Strategies 5 (May 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf (attached as Exh. MG-5).

importing from MISO. The Companies' ability to do this would if anything be enhanced by joining an RTO, given that they offer large geographic diversity and more efficient coordination of transmission usage.

This benefit will only increase as more renewables are added to the power system, as those resources also benefit from geographic diversity in weather phenomenon. Geographically diverse renewables, as well as a more diverse portfolio of solar and wind resources, provide more dependable capacity because their output profiles are weakly or negatively correlated. Multiple studies have confirmed that using imports and exports among grid operators to access that diversity is extremely valuable at high renewable penetrations.[32] Utilities' increasing reliance on gas generation is also increasing the benefit of geographic diversity, given repeated instances of localized failures of gas generation due to extreme weather.

Mr. Levitt is correct that the Companies would realize even more of these diversity benefits if they joined one of those large grid operators, though given their large transmission ties they already receive significant capacity benefit from imports today.

Q: What do the DOE data indicate about the transmission capacity for imports?

A: The DOE import data used in the above analysis also confirm that the Companies have strong physical capability to import power, contradicting the Companies' claim to the

[32] *See, e.g.*, Patrick Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, JOULE (Jan. 20, 2021), https://www.sciencedirect.com/science/article/pii/S2542435120305572; Aaron Bloom, et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, NREL (Oct. 2020), https://www.nrel.gov/docs/fy21osti/76850.pdf; Alexander E. MacDonald, et al., *Future cost-competitive electricity systems and their impact on US CO2 emissions*, Nature Climate Change 6, 526-531 (Jan. 25, 2016), https://repository.library.noaa.gov/view/noaa/14578 (articles collectively attached as Exh. MG-6).

contrary discussed in Section A above. The Companies' maximum net imports from each neighbor over the eight-year period are shown below. Summing each of these maxima, which do not occur at the same time, shows a total physical import capacity of 4,653 MW in the theoretical but implausible case that all ties were importing at the maximum at the same time. Over the eight-year period, the Companies' maximum net imports during any one hour were 1,515 MW. These figures are much higher than the assumptions used in the Companies' reserve margin analysis, as expected based on the flaws discussed in Section A above.

Neighboring grid	Maximum hourly imports, July 2015 - June 2023
MISO	1,420 MW
PJM	1,250 MW
TVA	937 MW
OVEC	710 MW
Gridliance	336 MW
Non-coincident import maximum	**4,653 MW**
Coincident net import maximum	**1,515 MW**

II. <u>The Companies understate the capacity value of renewable and storage resources.</u>

Q: What do the Companies assume for the capacity contribution of solar and battery storage?

A: The Companies assume solar offers a 78.6% capacity value in summer, which is reasonable, and a 0% contribution in winter,[33] which is not reasonable. The assumed 82% capacity value for 4-hour battery storage is also low.[34] As explained below, correcting

[33] LG&E-KU, Joint Application at 9.

[34] LG&E-KU Resp. to Joint Intervenors' Second Data Req. 60.a, Attachment 2 (provided May 4, 2023).

those assumptions would increase the accredited capacity of solar and storage the Companies are planning to add by a total of nearly 200 MW. More importantly, undercounting the capacity value of these resources while overstating the capacity value of gas, as discussed in the next section, reduced the amount of renewable and storage resources chosen in the Companies' economic analysis.

Q: Why does the Companies' analysis understate the capacity value of 4-hour battery storage?

A: A primary factor is that the analysis does not include the 1,100 MW of solar capacity that the Company plans to bring online over the next several years.[35] Many studies have documented that higher solar penetrations increase the capacity value of storage. By producing a large amount of energy during the early to mid-afternoon, solar tends to reduce the duration of system peak demand periods, allowing batteries with limited duration to better contribute throughout the peak demand period, as shown in the chart below.[36] NREL has calculated that on the U.S. power system up to 28 GW of batteries can be installed before their capacity value begins to decline. However, that figure doubles to around 60 GW once solar penetrations reach 10%.[37] The Companies note that planned solar resources will bring them to a 9% solar energy penetration by 2030.[38] Given the Companies' current lack of battery storage and high planned solar penetration,

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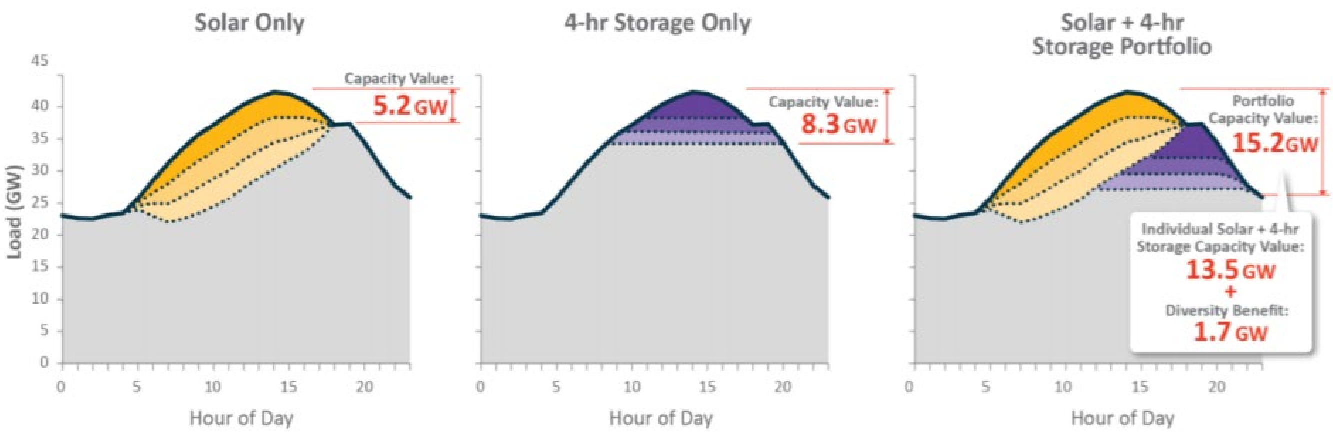
[35] *Id.* at D23.

[36] Nick Schlag, et al., *Capacity and Reliability Planning in the Era of Decarbonization*, Energy and Environmental Economics 6 (Aug. 2020), https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

[37] Paul Denholm et al., *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States*, NREL (2019), https://www.nrel.gov/docs/fy19osti/74184.pdf.

[38] Dir. Test. of David S. Sinclair at 22.

a more reasonable estimate is that 4-hour batteries would provide nearly 100% capacity value. That would increase the accredited capacity of the 125 MW Brown BESS by 22.5 MW.



Capacity Value Synergies between Solar and Storage.

Source: Capacity and Reliability Planning in the Era of Decarbonization[39]

Q: How would batteries have contributed during Winter Storm Elliott?

A: Experience during Winter Storm Elliott confirms that 4-hour batteries have sufficient duration to meet peak demand periods. The Companies curtailed load for about 4 hours on December 23, with nearly all of the MWh of firm load curtailment occurring during the first 3 hours of the event.[40] The Companies argue the extended multi-day period of high demand during Winter Storm Elliott would have challenged short-duration batteries.[41] However, this ignores that the multi-day period was actually brief periods of supply shortages that were repeatedly interrupted by periods when demand was lower or

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[39] Nick Schlag, et al., *Capacity and Reliability Planning in the Era of Decarbonization* Energy and Environmental Economics 6, (Aug. 2020), https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

[40] *Winter Storm Elliott: Events in the LG&E and KU Balancing Authority Area (BAA) Dec. 23-24, 2022*, LG&E-KU Resp. to Att'y Gen. First Data Req. 1.13 attachment 1, pp. 2, 9 (provided Mar. 10, 2023).

[41] Dir. Test. of Tim A. Jones at 12.

renewables, imports, or conventional generation were more abundant, which would have allowed batteries to recharge for the next brief period of shortage. Moreover, even long-lasting high demand events have extreme peaks lasting a few hours or less, as can be seen in the daily morning and evening peaks shown in the chart in Witness Jones' testimony showing hourly load profiles during the 2014 polar vortex.[42] Short-duration batteries are able to offer full capacity value towards meeting these peaks.

Q: Why is the assumed winter solar capacity value of 0% unreasonable?

A: Solar resources provide significant output during the winter, including during morning peak demand periods. Department of Energy data[43] show solar resources performed well during Winter Storm Elliott, with a 20-40% capacity factor during morning peak periods on both December 23 and 24, 2022. Solar performance is likely to be even better later in the winter, when temperatures are usually lower but the days are longer and the sun is higher in the sky. SPP has analyzed solar's winter capacity value, and found it is commonly in the range of 15% at solar penetrations comparable to what the Company is proposing to reach later this decade.[44] Assuming a 15% winter capacity value for solar, the 1,100 MW of solar the company proposes to add would provide around 165 MW of accredited capacity that was not accounted for in the Company's analysis.

Q: How will regional expansion of wind energy benefit the Companies?

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[42] *Id.*

[43] U.S. Dep't of Energy, Energy Info. Admin., *Form 930 Datafile for LGE/KU*, https://www.eia.gov/electricity/gridmonitor/knownissues/xls/LGEE.xlsx (accessed July 7, 2023).

[44] Southwest Power Pool, *2020 ELCC Wind and Solar Study Report* (July, 2021), https://www.spp.org/documents/65169/2020%20elcc%20wind%20and%20solar%20study%20report.pdf.

A: As noted in the preceding section, the capacity value of solar will increase as more wind is added in the region, and vice versa, as those resources tend to have opposite output profiles on a daily and seasonal basis because wind tends to produce more at night and during the winter. For example, MISO wind is accredited with a 40.3% capacity value in winter.[45] As explained above, MISO is developing major expansions of transmission and wind energy capacity, including large additions to the interconnection queue in the last year.[46]

The Companies can most directly benefit from this by contracting with these wind resources, which they can do regardless of whether they join an RTO. Purchasing wind helps create a more balanced generation portfolio, which would address a range of the Companies' claimed concerns, including cost, reliability, and emissions by providing low-cost zero-emission energy during nighttime and winter hours when solar resources' output is low. However, the Companies will receive some benefit indirectly regardless as higher wind output increases the availability of low-cost imports at night and during the winter.

[45] MISO, *Planning Year 2023-2024 Wind and Solar Capacity Credit Report*, (Mar. 2023), https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf.

[46] MISO, *Generator Interconnection: Overview* (last modified Mar. 30, 2023), https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf.

Q: How do you respond to the Companies' claim that "there is growing evidence around the country that moving away from fuel-dispatchable generation technologies too quickly is putting the grid at risk for blackouts due to lack of generation"[47]?

A: FERC's preliminary data indicate that Winter Storm Elliott caused the loss of more than 70,000 MW of generating capacity and led to more than 5,000 MW of firm load being shed in the Southeast.[48] Data from multiple regions indicate that gas generators accounted for the vast majority of generator outages, with coal the second largest contributor.[49]

Constrained gas supply and delivery appears to have been a major factor behind many of the generator outages during Winter Storm Elliott. As discussed in more detail in the next section, the Companies' own review shows reduced gas supply was the primary factor causing it to resort to rolling blackouts: "During the time of the load shedding event, derates attributable to the inability of Texas Gas to meet contractual delivery obligations ranged from 785MW to 943 MW. Derates unrelated to Texas Gas supply ranged from 45MW to 361MW."[50] As noted in the next section, the Companies' coal capacity also performed poorly during this time.

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[47] Dir. Test. of David S. Sinclair at 18.

[48] FERC et al., *December 2022 Winter Storm Elliott Inquiry into Bulk-Power System Operations – Status Update*, (June 15, 2023), https://www.ferc.gov/news-events/news/presentation-december-2022-winter-storm-elliott-inquiry-bulk-power-system.

[49] *See, e.g.*, Mike Bryson et al., PJM, *Winter Storm Elliott* (2023), https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx; MISO, Reliability Subcommittee, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023), https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

[50] *Winter Storm Elliott: Events in the LG&E and KU Balancing Authority Area (BAA) Dec. 23-24, 2022*, LG&E-KU Resp. to Att'y Gen. First Data Req. 1.13 attachment 1, p. 3 (provided Mar. 10, 2023).

To be clear, widespread systemic failures of gas generators, followed by equipment failures of coal generators, were the primary causes of the rolling blackouts and near-misses experienced during Winter Storm Elliott, Winter Storm Uri, the 2018 cold snap event, the 2014 polar vortex event, and other extreme weather events. Increasing dependence on gas generation only increases that risk. Renewable resource performance was strong across these events.

III. <u>The Companies overstate the reliability of gas and coal generation.</u>

Q: What do the Companies claim about the reliability of gas generation?

A: The Companies repeatedly overstate the dependability of gas with claims about how it is "fully dispatchable to provide customers energy when they need it, including cloudy but hot summer days and frigid, dark winter nights."[51] Recent experience contradicts this claim, including the rolling blackouts in which the Companies shed up to 317 MW of firm load during Winter Storm Elliott. However, the Companies' reliability analysis ignores the risk from events like Winter Storm Elliott and other cold snaps because it does not account for correlated outages of conventional generators. Accounting for correlated outages could reduce the capacity value of the proposed gas generators by 30 percentage points, reducing the accredited capacity of the Companies' proposed 1,242 MW of combined cycle additions to below 900 MW.

Q: Why are correlated outages ignored?

A: The Companies' reliability analyses are based on the incorrect assumption that conventional generator outages are random, uncorrelated events.[52] For example, if data

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[51] LG&E-KU, Joint Application at 8.

[52] LG&E-KU Resp. to Sierra Club Second Data Req. 2.7.b (provided May 4, 2023).

indicate that each unit of a certain type of resource has a forced outage 10% of the time, then the standard method predicts that the odds of two units having an outage at the same time are only 1% (10% times 10%). However, recent operating experience in Kentucky and elsewhere demonstrates that that prediction is invalid, as extreme winter weather and other events can cause many conventional generators to fail simultaneously through correlated outages due to equipment failures, fuel supply interruptions, and other problems, also known as "common mode" failures. Similarly, hot weather can cause many conventional generators to experience derates at the same time, reducing their capacity value. These problems are increasing as climate change causes more frequent and extreme heat, as well as more severe weather of various types.

The Company uses capacity accreditation methods that account for how correlated output profiles of wind, solar, or storage resources reduce their capacity value, but not how similar correlations reduce the capacity value of conventional generators. To ensure a level playing field and prevent sub-optimal ratepayer outcomes in its resource selection, the Companies should account for correlations in the output of all generators.

Q: Have analyses quantified how correlated outages reduce the capacity value of gas generation?

A: Yes. The Companies' consultant Astrape recently completed analysis showing that the capacity value of conventional generators in part of PJM can be 24% lower in winter and 15% lower in summer relative to their nameplate capacity.[53]

[53] Advanced Energy United, *Getting Capacity Right: How Current Methods Overvalue Conventional Power Sources* (Mar. 2022), https://www.aee.net/aee-reports/getting-capacity-right-how-current-methods-overvalue-conventional-power-sources (attached as Exh. MG-7).

During Winter Storm Elliott in Kentucky, the reduction in the capacity value of gas generators was even greater. Hourly output data tracked by EPA's Continuous Emissions Monitoring System show that the Companies' gas generators dropped from providing 70% of their maximum net winter capacity at the start of the load shed event on the evening of December 23, to around 62% of their maximum at the end of the 4-hour event.[54] This suggests a reduction in winter capacity value of 30-38%. Conducting the analysis without the 138 MW Brown 10 gas unit, which the Companies note was on outage since early December, shows gas's fleetwide performance starting at 74% and dropping to 65%. This suggests a reduction in winter capacity value of 26-35%. The data show the Companies' coal generators were running at 81-83% of their maximum net winter capacity, which is also much lower than normal for a record demand period. This data confirms the Companies' own analysis documenting these fleetwide failures.[55]

Q: Based on those results, what is a reasonable estimate of the capacity value provided by the 1,242 MW of proposed gas combined cycle capacity?

A: It would be significantly lower than the Company's estimate. Assuming a 30% reduction in capacity value based on the performance of the existing gas fleet during Elliott, the 1,242 MW from the two combined cycles would provide 869 MW of dependable capacity.

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[54] EPA, *Clean Air Markets Program Data: Custom Data Download* (Mar. 6, 2023), https://campd.epa.gov/data/custom-data-download.

[55] *Winter Storm Elliott: Events in the LG&E and KU Balancing Authority Area (BAA) Dec. 23-24, 2022*, LG&E-KU Resp. to Att'y Gen. First Data Req. 1.13 attachment 1, p. 3 (provided Mar. 10, 2023).

Q: Have other studies quantified the impact of correlated outages?

A: Yes, a recent paper used NERC data[56] to demonstrate that conventional generators experience common mode correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events. As shown below, in the SERC region that includes Kentucky, simultaneous winter generation outages (red line) are roughly twice the level of outages that would be expected under the assumption that generator outages are uncorrelated independent events (gray area), with about 15-20 GW more concurrent outages than expected.[57] In the Reliability First Corporation region (which covers PJM and parts of eastern MISO) concurrent winter outages exceeded the level of expected outages by an even larger margin, with 50 GW of outages versus an expectation of 20-25 GW. Because large RTOs like PJM have significant geographic diversity in their load and generation, PJM has been able to avoid shedding firm load during these correlated outages.

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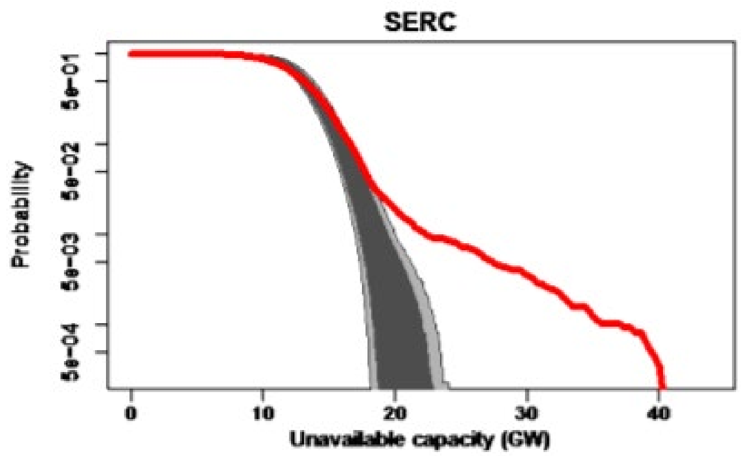
[56] Sinott Murphy et al., *Resource Adequacy Risks to the Bulk Power System in North America*, Carnegie Mellon Elec. Indust. Cent. 29 https://www.andrew.cmu.edu/user/fs0v/papers/CEIC_17_02R1%20Resource%20adequacy%20risks%20to%20the%20bulk%20power%20system%20in%20North%20America.pdf,

[57] *Id.* at S-22.



Simultaneous generator outages in Southeast (red) are twice as high as expected if they were actually uncorrelated events (gray area).[58]

Q: Do the data indicate which resources are experiencing correlated failures?

A: Yes, the NERC data show that correlated forced outages tend to occur more frequently at certain types of conventional generators, with simple cycle gas generators experiencing the highest correlated outage rate in SERC.[59]

Rather than using a higher winter reserve margin as the Companies propose, a more accurate and fair way to account for the correlated outages of certain resources would be to reduce those resources' capacity value. The correlated output patterns of wind or solar resources are typically accounted for in calculating their capacity value, so failing to account for correlated outages of conventional generators overstates their capacity contributions relative to renewable resources.

[58] *Id.*

[59] *Id.* at 27.

Q: Aside from overvaluing conventional generators' capacity value relative to alternatives, what harm can result from failing to account for correlated conventional generator outages?

A: Accurately assessing the capacity value contributions of resources is critical for ensuring that the Companies' planned resource portfolio is adequate to meet reliability needs. Overestimating the capacity value of new gas generation not only results in an economically suboptimal resource mix, but it can also cause electricity supply to fall short of demand. Adding gas capacity that tends to fail at the same time as existing gas generators provides less capacity value than expected. This is particularly true if new gas generators are susceptible to the same outage causes as the existing fleet, like dependence on the same gas supply fields and pipelines.

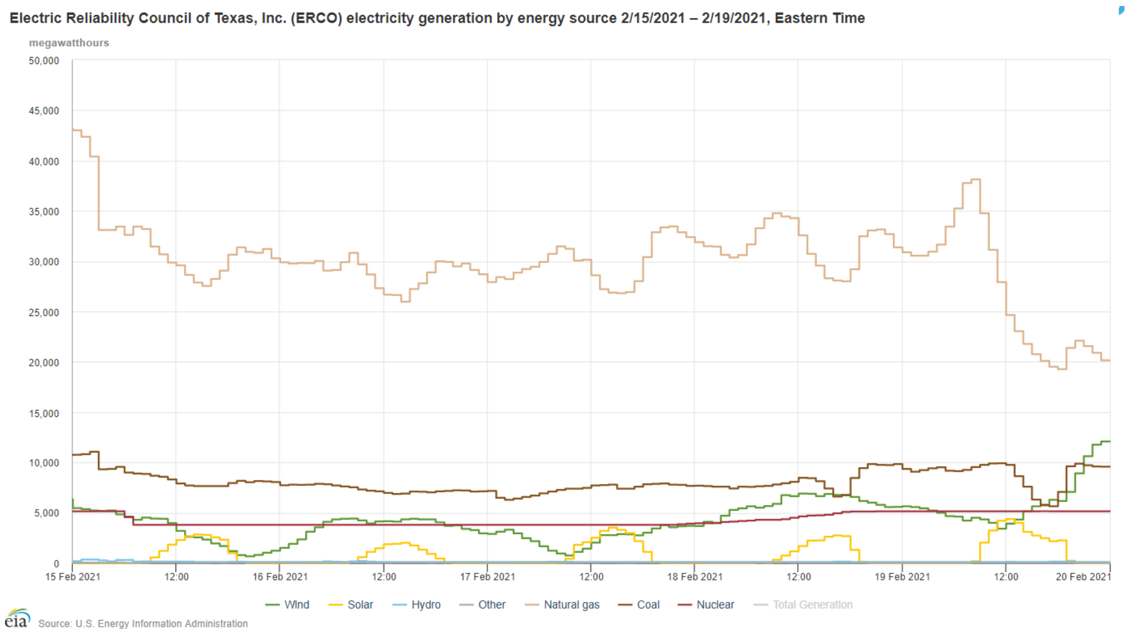
In contrast, adding renewable and storage generation that is not affected by fuel delivery and other constraints reduces risk and increases resilience by diversifying the generation mix. This finding has been confirmed by high levels of renewable output during recent extreme cold weather events.

Q: What caused the rolling blackouts in Texas during Winter Storm Uri?

A: Similar correlated failures of gas and coal generators were the primary cause of the large and extended power outages in Texas caused by Winter Storm Uri in February 2021.[60] As shown below, a steep drop in gas and coal generation (light brown and dark brown, respectively) early on February 15, 2021, coincided with the start of the rolling outages in ERCOT. In contrast, solar output (yellow) as a share of its nameplate capacity was high

[60] *See* FERC & NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* 17 (2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

on each day of the event, as solar panels operate at a higher efficiency at lower temperatures.



ERCOT Generation Mix during Winter Storm Uri[61]

Other recent events in which gas generators experienced widespread outages include the 2018 Bomb Cyclone,[62] the 2014 Polar Vortex event,[63] and another cold snap that led to rolling power outages in Texas and parts of the Southwest in February 2011.[64] During a

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[61] *See* U.S. Energy Info. Admin., *Hourly Electric Grid Monitor*, https://www.eia.gov/beta/electricity/gridmonitor/expanded-view/electric_overview/US48/US48/GenerationByEnergySource-4/edit (last visited July 10, 2023) (created using interactive graphs).

[62] U.S. Energy Info. Admin., *January's Cold Weather Affects Electricity Generation Mix in Northeast, Mid-Atlantic* (Jan. 23, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34632.

[63] NERC, *Polar Vortex Review* iii (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[64] FERC & NERC, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations* 1 (2011), https://www.ferc.gov/sites/default/files/2020-05/ReportontheSouthwestColdWeatherEventfromFebruary2011Report.pdf.

cold snap on January 17, 2018, TVA, AECI, and LGE/KU lost a combined 5,000 MW of generation, or 29% of their generating capacity, though LGE/KU does not appear to have lost any generation during that event.[65]

Hot weather can also cause conventional generators to experience outages and derates at the same time, reducing their capacity value, as occurred in California in August 2020[66] and September 2022; during the second event, correlated outages and derates reduced the capacity contributions of California's gas generators by around 10-15%.[67] As another example, many types of conventional power plants in the Southeast, including TVA's Browns Ferry nuclear plant, have been forced to reduce their output when extreme heat and drought have affected their water supply.[68]

Q: Can the Companies take steps to prevent the loss of gas supply?

A: Not effectively, as the primary factor in recent events has been the freezing of gas supply wells, which are primarily in other regions. Press reports about Winter Storm Elliott

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[65] FERC & NERC, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* 6 n.6, 35 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf (noting that the TVA Reliability Coordinator footprint includes TVA, AECI, and LGE/KU).

[66] *See* Cal. Indep. Sys. Operator et al., *Root Cause Analysis: 2020 Extreme Heat Wave* 1 (2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[67] Regenerate California, *California's Underperforming Gas Plants, How Extreme Heat Exposes California's Flawed Plan for Energy Reliability* (2023), https://caleja.org/wp-content/uploads/2023/06/2023-Regenerate-Heat-Wave-Report.pdf.

[68] *See* Julia Pyper, *Electricity Generation "Burning" Rivers of Drought-Scorched Southeast*, Sci. Am. (June 29, 2012), https://www.scientificamerican.com/article/electricity-generation-buring-rivers-drought-southeast/; Associated Press, *Heat and Drought Shut Down TVA Reactor*, Ala. Pub. Radio (Aug. 17, 2007, 6:50 AM), https://www.apr.org/2007-08-17/heat-and-drought-shut-down-tva-reactor.

explain that gas production dropped off markedly as wells from Texas to Appalachia froze, severely limiting gas deliveries:

> *On Dec. 23, US natural gas production suffered its worst one-day decline in more than a decade, with roughly 10% of supplies wiped out because of wells freeze-offs. Output was as low as 84.2 billion cubic feet on Saturday, a 16% decline from typical levels, before a slow recovery started, according to BloombergNEF data based on pipeline schedules… Most of the output loss was seen in the Northeastern Appalachia basin, where supplies plunged to the lowest level since 2018. US natural gas futures posted gains on Tuesday as supplies remained severely constrained by freeze-offs. Supplies from Appalachia to the Tennessee Valley and the Midwest more than halved from typical levels, according to pipeline flow data compiled by BloombergNEF.*[69]

With more than one-third of U.S. gas production now concentrated in a relatively narrow area at the intersection of West Virginia, Ohio, and Pennsylvania,[70] and declining production in areas like the Gulf of Mexico that have historically supplied these pipelines,[71] the risk of supply interruptions appears to be increasing.[72]

Recent expansion of gas generating capacity in neighboring regions like PJM, MISO, and TVA puts even further strain on gas supply and transportation infrastructure during peak electric demand periods than was observed during these historical events.

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[69] Gerson Freitas, Jr. et al., *America's electrical grid barely escaped a calamity as massive storm exposes a vulnerable natural-gas infrastructure*, Fortune (Dec. 27, 2022, 2:36 PM EST), https://fortune.com/2022/12/27/america-electrical-grid-barely-escaped-a-calamity-as-massive-storm-exposes-a-vulnerable-natural-gas-infrastructure/.

[70] U.S. Energy Info. Admin., *Today in Energy: Shale Natural Gas Production in the Appalachian Basin Sets Records in the First Half of 2021* (Sept. 1, 2023), https://www.eia.gov/todayinenergy/detail.php?id=49377.

[71] U.S. Energy Info. Admin., *Today in Energy: Appalachia, Permian, Haynesville Drive U.S. Natural Gas Production Growth* (Aug. 28, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36934.

[72] Naureen Malik, *Why Natural Gas Makes the US Power Grid Vulnerable*, Bloomberg (June 27, 2023), https://governorswindenergycoalition.org/why-natural-gas-makes-the-us-power-grid-vulnerable/.

The Companies have limited dual fuel capability in their gas fleet, acknowledging that only Brown units 8-11 have dual fuel capability with onsite fuel oil storage.[73] Accurately accrediting the capacity value of the proposed gas generators during extreme winter weather is particularly important, because peak winter demand appears to drive the Companies' claimed incremental capacity need. Reducing the capacity value of new gas generators, while increasing that of renewable and storage resources for the reasons discussed in the preceding section, could have shifted the analysis of optimal resource additions.

IV. <u>Other factors cause the Companies to overstate the need for capacity.</u>

A. <u>The Companies' Assumed Value of Lost Load is excessive.</u>

Q: What is the Companies' assumption for the value of lost load, and how does it compare to the assumption used in other regions?

A: The Companies' assumed $21,000/MWh Value Of Lost Load (VOLL)[74] is excessive. The VOLL reflects the assumed average cost to customers for curtailment of firm load. For comparison, MISO has concluded that $3,537/MWh best reflects the VOLL, based on a meta-analysis of 24 studies in the Midwest region,[75] in contrast to the four national

[73] LG&E-KU Resp. to Sierra Club Second Data Req. 2.1.b (provided May 4, 2023).

[74] *See* Dir. Test. of Stuart A. Wilson, Exh. SAW-1, 2022 RFP Minimum Reserve Margin Analysis, at D19.

[75] MISO, *Value of Lost Load (VOLL) and Scarcity Pricing*, 19, 31 (September 10, 2020), https://cdn.misoenergy.org/20200910%20MSC%20Item%2005b%20RAN%20Value%20of%20Lost%20Load%20(IR071)472095.pdf.

studies included in the Companies' analysis. ERCOT has similarly used estimates of $2,000/MWh, $5,000/MWh, and $9,000/MWh for the VOLL.[76]

Q: What impact does the assumed Value Of Lost Load have on the Companies' calculation of the optimal reserve margin?

A: A higher assumed VOLL increases the estimated cost of outages, and thus the optimal reserve margin. Analysis for ERCOT conducted by Astrape using the SERVM model, the same consultant and model used for the Companies' analysis, confirmed that varying the assumed VOLL has a large impact on the economically optimal reserve margin, particularly at higher values.[77] Specifically, the economically optimal reserve margin was found to be 10.25% at a $5,000/MWh VOLL, 11% at $9,000/MWh, and 13.25% at $30,000.[78] Earlier analysis by the Brattle Group confirms the sensitivity to that assumption.[79] This suggests that the Companies assuming a VOLL of $21,000/MWh may overstate the optimal reserve margin by several percentage points. A reduction in the reserve margin of this magnitude significantly reduces the Companies' claimed capacity

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[76] ERCOT, *2022 Biennial ERCOT Report on the Operating Reserve Demand Curve* (October 31, 2022) https://www.ercot.com/files/docs/2022/10/31/2022%20Biennial%20ERCOT%20Report%20on%20the%20ORDC%20-%20Final_corr.pdf.

[77] Astrape Consulting, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*, 15 (January 15, 2021) https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf (attached as Exh. MG-8).

[78] *Id.* at 26.

[79] The Brattle Group, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region* 37 n.42 (2018), https://www.brattle.com/wp-content/uploads/2021/05/15258_estimation_of_the_market_equilibrium_and_economically_optimal_reserve_margins_for_the_ercot_region.pdf ("[V]arying the VOLL to range from $5,000 to $30,000 changes the EORM to range from 8.25% to 10.5%, respectively.") (attached as Exh. MG-9).

need by several hundred MW; for example, 3% of the Companies' projected 2028 peak load of 6,319 MW equates to a change in capacity need of 190 MW.

Q: Are there other reasons to question the Companies' Value of Lost Load assumption?

A: The studies cited by the Companies note widely divergent estimates of outage costs across and within customer classes. At least two of the four studies the Companies relied on to arrive at the $21,000/MWh assumption noted that their survey design may not have adequately accounted for the reduction in outage costs due to the presence of backup generator equipment.[80] It is also intuitive that there would be a positive correlation between a customer having high outage costs and the presence of backup generation, as the latter is a way to mitigate the former, but it is not clear if this was taken into account in the studies.

All of the studies cited by the Companies are from 2000 to 2009, and there is reason to believe increased use of backup generation and other factors may have reduced the cost of outages since then. Backup generators have become more common over time due to increasing reliance on sensitive electronic equipment and declining costs for backup, including due to cost declines for batteries.

Q: Based on these facts, what is your conclusion?

A: In short, the true cost of shortages is significantly lower than the Companies' assumption, which would reduce the optimal reserve margin by at least several percentage points,

[80] Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States* 97 (2009), https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf ("[T]he presence of the generator and the tally of interruption costs are separated, so it is not clear if the respondent is adequately taking the backup generation capability or costs into consideration.").

which in turn would reduce the need for capacity by several hundred MW, further negating the need for the two proposed combined cycle generators. As noted in Mr. Levitt's testimony, the Companies could further reduce their reserve margin by joining PJM and directly tapping into the diversity benefits offered by its large footprint.

Q: Are there additional reasons why the Companies' assumed reserve margin is too high?

A: As discussed above, the Companies can respond to a shortfall by importing more power from RTOs. Prices are capped at $3,500/MWh in MISO and $3,700/MWh in PJM, which effectively sets a ceiling on the price at which the Companies could buy power during a shortfall. This helps ensure that if the Companies are willing to pay even modestly more than those price caps, supply is likely to be available. However, the Companies' VOLL assumption is about 6 times higher than the price caps in MISO and PJM.

The Companies' reserve margin analysis also assumes there are very high costs associated with generation shortages even prior to the point at which firm load shedding would begin. The Companies' analysis claims this is needed to reflect that:

> As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply… The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power.[81]

There are several problems with this assumption. First, the scarcity price adders reach $21,000/MWh, which as noted above is nearly six times higher than the price caps in the MISO and PJM markets. The RTO price caps would thus prevent prices from going that high. In response to discovery questions, the Companies attempt to defend the

[81] Dir. Test. of Stuart A. Wilson, Exh. SAW-1, p. D21.

scarcity price adders by arguing that "During Winter Storm Elliott on December 23 and 24, the Companies purchased power at prices in excess of $3,000/MWh. These purchases corroborate the Companies' scarcity price curve."[82] However, prices of around $3,000/MWh would still be under the price caps in MISO and PJM, confirming my point that a $21,000/MWh price adder does not reflect realistic market prices.

Second, this assumption appears similar to an Operating Reserve Demand Curve, which is a tool used in RTO markets to set prices during periods of shortage. However, there is no reason to apply that assumption in a non-RTO market where there are no centralized market prices, as a shortage would not impose a cost on customers until firm load is shed.

This assumed price adder could greatly inflate the Companies' calculated reserve margin need. Because a shortage inherently precedes all losses of load, but shortages can also occur without leading to a loss of load, shortages will tend to occur more frequently and last longer than actual loss of load. As a result, the assumed value of avoiding this cost would significantly weight the scale towards a higher reserve margin, which in turn overstates the need for capacity.

Q: Are there other assumptions that may overstate the need for capacity?

A: The Companies assume the small-frame SCCTs Haefling 1-2 and Paddy's Run 12 will be retired in 2025. However, in discovery the Companies note that this retirement will not happen until the units suffer a major failure, which could be significantly later than 2025.[83] If some or all of these units are able to operate longer, this would add 47 MW of

[82] LG&E-KU Resp. to Sierra Club First Data Req. 1.8.b (provided Mar. 10, 2023).

[83] LG&E-KU Resp. to Sierra Club Second Data Req. 2.8 (provided May 4, 2023).

summer capacity and 55 MW of winter capacity that reduces the Companies' need for other capacity. While it would be risky to assume that all three units will continue operating indefinitely, it seems likely that at least one or two will be able to remain online.

B. <u>The Companies' load growth assumption may be too high.</u>

Q: Are the Companies' assumptions about the impact of heat pump incentives in the IRA reasonable?

A: No. While the Companies' load forecast does account for increased electric load due to heat pumps displacing gas heating, it does not appear to account for the offsetting impact of heat pumps reducing load by displacing less efficient electric resistance heating.[84] Given the significant prevalence of electric heating in Kentucky, the majority of which is from inefficient resistance heating furnaces,[85] the move to much more efficient heat pumps can significantly reduce load. Even at outside temperatures of zero degrees Fahrenheit, modern heat pumps can be more than twice as efficient as resistance heating,[86] and analysis in Minnesota confirms the reduction in electricity consumption for

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[84] Dir. Test. of Tim A. Jones at 26-27.

[85] EIA data show that only 22% of homes in Kentucky use heat pumps, Energy Info. Admin. (Mar. 2023), https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Space%20Heating.pdf, but 49% of homes use electricity, Energy Info. Admin. (Mar. 2023), https://www.eia.gov/consumption/residential/data/2020/state/pdf/State%20Space%20Heating%20Fuels.pdf. This indicates that 27% of total homes, or the majority of homes with electric heat, use a technology other than heat pumps, which in most cases is presumably resistance heating. The first citation also notes that 66% of homes in Kentucky use furnaces, which suggests a large share of the resistance heating is through ducted electric furnaces, which are the least efficient form of electric heat. *See* U.S. Dep't of Energy, *Electric Resistance Heating*, https://www.energy.gov/energysaver/electric-resistance-heating (last visited July 14, 2023). Because these homes already have ducts, conversion to heat pumps is even more likely.

[86] R.K. Johnson, *Measured Performance of a Low Temperature Air Source Heat Pump*, U.S. Dep't of Energy 14 (Sept. 2013), https://www.nrel.gov/docs/fy13osti/56393.pdf.

homes that switch from legacy electric heating to heat pumps.[87] Accounting for this benefit can have a significant impact on the Companies' claimed incremental capacity need, because winter demand appears to drive the need for capacity and the Companies' peak winter demand is heavily driven by heating load.

V. Batteries are superior to gas in providing flexibility.

Q: What do the Companies claim regarding how gas can meet flexibility needs?

A: The Companies overstate the challenges associated with reliably integrating renewable resources like solar, while also overstating the value of gas generators for addressing those claimed challenges. For example, LGE/KU Witness Bellar argues that the proposed gas combined cycle generators'

> ramping ability is particularly useful to support the Companies' proposed expanding solar portfolio, including the solar facilities proposed in this case. For solar generation, even a passing cloud can greatly affect solar generation immediately, and, of course, solar generation is not possible at all as soon as it becomes dark. Thus, increased reliance on solar generation requires the ability to very quickly respond to rapid changes in the amount of solar generation. The fast ramping times NGCCs can achieve will position the Companies well to react to the volatility and intermittence of solar generation allowing for the integration of greater levels of solar generation.[88]

Q: What is your reaction to these claims?

A: First, clouds and other localized weather events do not have a significant impact on the total output of a solar generation fleet, given that geographic diversity across even a

[87] Minn. Div. of Energy Res. & Minn. Dep't of Com., *Air Source Heat Pump Efficiency Gains from Low Ambient Temperature Operation Using Supplemental Electric Heating* 15-17 (June 2011), https://www.leg.mn.gov/docs/2014/other/141021.pdf.

[88] Bellar Dir. Test. at 10.

relatively small number of solar installations cancels out those localized impacts.[89] Solar output can also be forecast. In contrast, the instantaneous and unpredictable failures of large conventional generators create a far larger need for fast-acting reserves. As a result, this concern is overstated.

Second, gas combined cycle generators are quite inflexible relative to batteries, and even other types of gas generators. The steam generator component of a combined cycle has relatively slow ramp rates and high minimum output levels, with the Companies noting each proposed combined cycle generator has a minimum output level of 226 MW.[90] In contrast, batteries offer nearly instantaneous response with no minimum output level. Batteries can also absorb power during periods of low demand or high supply, including renewable output that would have been curtailed. Fossil generators cannot absorb excess power. Batteries also offer twice the ramp range that conventional generators offer, as they can ramp between fully charging and fully discharging. As a result, there is no need for the proposed gas combined cycle generators to provide flexibility.

Q: Do the Companies acknowledge these benefits of batteries?

A: They do, in admitting that the value of batteries' fast flexibility was not quantified in the Companies' economic analysis:

> Brown BESS [Battery Energy Storage System] might provide quantifiable benefits the Companies have not attempted to quantify here. For example, battery energy storage systems can provide instantaneous load following and

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[89] *See, e.g.*, Lawrence Berkeley Nat'l Laboratory, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (Sept. 2010), https://eta-publications.lbl.gov/sites/default/files/report-lbnl-3884e.pdf.

[90] Sinclair Dir. Test. at 15.

> compensation for fluctuations in intermittent generation that might otherwise require rapid ramping from the Companies' SCCT and NGCC units, reducing wear (and related costs) on such units. The Brown BESS might also allow the Companies to carry lower amounts of spinning reserves, which could also provide savings.[91]

Q: Do batteries offer other benefits?

A: Batteries are highly modular with a small footprint, so they can be added when, where, and in the precise quantity that is needed. This makes them highly useful for providing a range of additional benefits, like deferring needed transmission or distribution upgrades, including costs or congestion associated with interconnecting new generators or local reliability problems caused by generator retirements. The 100 MW minimum size requirement in the Companies' RFP likely excluded these valuable smaller projects.

Q: Are there are other arguments put forward by the Companies to which you would like to respond?

A: The Companies argue that solar development costs and timelines are risky due to increasing costs.[92] The Companies note that the cost of raw polysilicon was \$45/kg when they filed their testimony, yet the cost is now under \$30/kg, and under \$20/kg for Chinese production.[93]

The Companies' argument also ignores that these supply chain constraints and cost pressures are affecting all generation types, including gas generators.[94] Increasing

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[91] Wilson Dir. Test. at 34.

[92] Sinclair Dir. Test. at 20.

[93] PV Magazine, *Polysilicon Prices Plunge Worldwide on Bearish Market Sentiment* (June 2, 2023), https://www.pv-magazine.com/2023/06/02/polysilicon-prices-plunge-worldwide-on-bearish-market-sentiment/.

[94] *See, e.g.*, Diego Mendoza-Moyers, *Consumer Advocate Challenges El Paso Electric as Utility's Newest Power Plant Comes in \$37 Million Over Budget*, El Paso Matters (July 11, 2023),

labor and material costs, equipment shortages, and transport constraints will also affect the timeline and cost of building a gas generator. In the case of the gas generators built by the Companies, those higher costs and risks related to cost and timeline are passed through to ratepayers.

These inflationary pressures on most cost inputs appear to be easing over time, which highlights an important benefit of renewable and storage resources over gas. Gas generator equipment would have to be ordered much sooner than equipment for building solar and storage resources, given the significantly longer time required to construct a gas generator, and the fact that gas generator (and particularly combined cycle) equipment must be tailored to the needs of a particular installation while solar and storage equipment is highly modular and thus can be procured closer to its installation date.

Q: Please summarize your testimony.

A: Multiple errors cause the Companies to overstate the need for capacity. The Companies also understate the reliability contributions of renewable and storage resources and overstate those of gas generators. In total, correcting those errors reduces the need for capacity by at least 1,000 MW, displacing more than the capacity value that would be provided by the proposed gas generators after accounting for correlated outages. As a result, the proposed gas combined cycle generators are not needed.

Q: Does this conclude your testimony?

A: Yes.

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https://elpasomatters.org/2023/07/11/el-paso-electric-plant-to-cost-more-than-expected-increase-utility-bills/.

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of direct testimony in this action is being electronically transmitted to the Commission on July 14, 2023, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
JOE F. CHILDERS