STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)

DIRECT TESTIMONY OF JENNIFER CHEN ON BEHALF OF CLEAN ENERGY BUYERS ASSOCIATION

May 28, 2024

Q: Please state your name and title.

A: My name is Jennifer Chen. I am the Senior Manager of Clean Energy at the World Resources Institute (WRI) and Board Member of the Council for New Energy Economics (NEE). WRI is a nonpartisan, nonadvocacy, and nonprofit think tank, and NEE is a nonprofit organization committed to helping utilities and energy decision-makers navigate rapidly evolving utility industry economics.

Q: Please describe your education and professional experience.

A: Previous to WRI, I led electricity policy work at the Nicholas Institute at Duke University. I was also an independent consultant working with R Street Institute, the Clean Energy Buyers Institute, and renewable energy and consumer advocacy groups. I was an attorney with the Natural Resources Defense Council and at the United States Federal Energy Regulatory Commission (FERC).

I earned a J.D. from New York University School of Law and a Physics Ph.D. from the University of Chicago. I serve on the Advisory Board at the Horizon Climate Initiative and was appointed by Secretary Granholm to the U.S. Department of Energy's Electricity Advisory Committee.

Q: Please summarize your current responsibilities with WRI.

A: My current employment responsibilities are as follows:

- Lead WRI work on electricity market and transmission issues.
- Engage with the expert community on resource adequacy issues across the US.
- Research, write, and publish objective and well-supported analysis.
- Convene stakeholders, advise decision makers, and educate the public.

Q: Have you previously testified before the North Carolina Utilities Commission (the Commission)?

A: No, but I have provided expert testimony on electricity issues before the U.S. Congress, FERC, and other state public utility commissions.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to comment on the 2023 Resource Adequacy Study for Duke Energy Carolinas & Duke Energy Progress (hereinafter, the Astrapé Study), which is the reserve margin study filed by Duke Energy Carolinas and Duke Energy Progress (collectively, the Companies or DEC/DEP) as Attachment I to its initial filing to support its target reserve margin proposal, and to provide some broader perspectives on reliability and customer costs.

Q: What is the reserve margin and how is it related to reliability?

A: Resource adequacy—ensuring the system has sufficient resources to balance supply and demand now and into the future—is one component of a reliable system but by itself cannot guarantee reliability. Completely failsafe reliability is impossible to achieve and building more resources can have diminishing marginal returns. Thus, the foundational questions utilities and state public utilities commissions should ask are what level of reliability is acceptable and at what costs.

The Astrapé Study focuses on resource adequacy and models how much extra capacity (*i.e.*, reserve margin) is needed beyond the projected future demand determined in DEC/DEP's long-term load forecast. This analysis is based on an industry rule of thumb in place since the 1940s: the 1-in-10 Loss of Load Expectation (LOLE) criterion.[1] Under this criterion, the utility builds out its system to withstand all but rare grid events that do not typically happen more than once in ten years.

Costs are not considered in setting the resource adequacy requirements to meet or exceed this criterion. The costs for building and maintaining the resources needed to meet the criterion could be quantified after the resource adequacy requirements are determined. However, DEC/DEP have not yet quantified the costs of the capacity that it would need to build to satisfy the proposed higher reserve margin requirements.[2]

Q: How is reserve margin generally established?

A: The reserve margin is expressed as a percentage of extra resources needed on top of the forecasted demand to meet resource adequacy targets. Because the reserve margin is a percentage, the total megawatts needed to satisfy the reserve margin will increase with a higher long-term load forecast. Generally, utilities and grid operators make conservative assumptions in forecasting load to make sure they are not deficient in resources. Certain utilities also have a financial incentive to forecast robust load because cost-of-service business models reward utilities for capital investments. These conservative assumptions in the long-term load forecast build in extra capacity in addition to the reserve margin. Thus, load forecasts generally tend be higher than actual peak loads, and reserve margins sit on top of these conservative load forecasts. Even in the case of Winter Storm Elliot,

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[1] There are criteria other than LOLE that grid operators can use. *See* Lawrence Berkley National Laboratory, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems (June 2023). Accessed at: https://eta-publications.lbl.gov/sites/default/files/ra_project_-_final.pdf.

[2] "The Companies have not quantified the additional cost from the increase in winter planning reserve margin relative to the impacts of the load forecasts analyzed in the CPIRP and its resulting impact to resource selection." Duke Response to CEBA DR4-3 (Exhibit 1 at 2).

which was an unusually high demand peak, the DEP/DEC long-term load forecast was not too far from the actual peak.[3]

DEC/DEP's resource adequacy requirements will grow based on both the Companies' January 2024 load forecast increase and the Astrapé recommended reserve margin increase. Taking the latest load forecast increase as a given, Astrapé's recommendation to raise DEC/DEP's current target reserve margin of 17% to 22%[4] will produce an increase of 1,831 MW in additional capacity for 2031. Each percentage increase in the reserve margin for the 2031 forecasted load translates to an increase of about 366 MW in capacity procurement.[5]

Q: Is a large reserve margin indicative of greater reliability?

A: No, the reserve margin only indicates the quantity and not quality of available capacity, which will depend on the types and vintages of power plants and fuel delivery systems. While a recommended reserve margin is modeled based on historic outages, as a single

[3] Duke Response to CEBA DR4-23 (Exhibit 1 at 9) ("After normalizing for weather, the DEP system peak was 399 MW (2.8%) below the forecast that appeared in the 2018 IRP, while the DEC system peak was 57 MW (0.3%) below the forecast from the 2018 IRP. In both cases, the recorded peak exceeded the forecast peak, which was computed using what was calculated as normal weather at the time the forecast was made.").

[4] Astrapé Study at 8.

[5] "SPA Table 2-6 DEC has a projected System Winter Peak Load of 21,120 MW in 2031. A 17% winter planning reserve margin results in 3,590 MW of firm winter reserve capacity above the weather-normal projected winter peak. A 22% winter planning reserve margin results in 4,646 MW of firm winter reserve capacity above the weather-normal projected winter peak. The difference in firm winter reserve capacity required under a 22% winter planning reserve margin compared to a 17% winter planning reserve margin is 1,056 MW. From SPA Table 2-7 DEP has a projected System Winter Peak Load of 15,504 MW in 2031. A 17% winter planning reserve margin results in 2,636 MW of firm winter reserve capacity above the weather-normal projected winter peak. A 22% winter planning reserve margin results in 3,411 MW of firm winter reserve capacity above the weather-normal projected winter peak. The difference in firm winter reserve capacity required under a 22% winter planning reserve margin compared to a 17% winter planning reserve margin is 775 MW." Duke Response to CEBA DR4-2 (Exhibit 1 at 1).

metric, it does not provide information on the resources' expected performance and ability to contribute to a reliable electricity supply.[6]

A fleet of generators with lower outage rates would not need as high of a reserve margin to maintain reliability as a fleet that experiences more frequent and serious outages, whether due to insufficient maintenance and weatherization or reliance on pipelines and fuel supplies prone to interruptions.

In other words, a lower reserve margin requirement can be an indicator of a well-performing and efficiently managed fleet.[7] A pure cost-of-service business model that prioritizes capital expenditures may not sufficiently incentivize operational improvements, smaller upgrades, and maintenance that improves the performance of a fleet. Appropriately designed incentives and updating a fleet with newer and more efficient energy resources can help improve performance of committed capacity. For example, PJM Interconnection LLC (PJM) rewards capacity resources for overperformance and penalizes them for underperformance. PJM has cited improvements in generator performance as a driver in

[6] Higher planning reserve margins and excess reserve capacity ahead of the season do not necessarily equate to guaranteed reliability, especially during extreme weather events. For example, ERCOT reported a 49.8% Anticipated Reserve Margin in NERC's 2020-2021 Winter Reliability Assessment, and subsequently experienced 20,000 MW of firm load shed over a four-day period. *See* National Association of Regulatory Utility Commissioners, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms at 21 (Nov. 2023). Accessed at: https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3.

[7] Note that in Japan, which is known for efficiency and well-maintained infrastructure, Japanese utilities are required to have a reserve margin of 3%. *Japan Electricity Security Policy*, International Energy Agency, https://www.iea.org/articles/japan-electricity-security-policy (last visited May 24, 2024).

reducing its reserve margin.[8] In a sensitivity analysis, PJM found that each 1% increase in the forced outage rate required PJM to increase its reserve margin by 1.36%.[9]

Going into Winter Storm Elliot, DEC and DEP's weather normal projected reserve margins were approximately 25% and 18%, respectively. The North American Electric Reliability Corporation's (NERC) November 2022 report projected that SERC-East (North and South Carolina combined) had a weather normal On-Peak Reserve Margin of approximately 24%,[10] which was higher than the proposed reserve margin in the Astrapé Study. With that reserve margin, DEC/DEP should have sufficient capacity to withstand a 1-in-10 LOLE event according to the Astrapé Study. Thus, long-term load forecasting and resource adequacy planning and procurement were not the issues that led to the firm load shed during Winter Storm Elliot. Instead, as detailed in reports from NERC, FERC, and other entities, the problems included inaccurate short-term load forecasting, power plant failures, and gas pipeline interruptions.[11]

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[8] "Continued improvements in generator performance in the region served by PJM are helping to reduce the percentage of reserve capacity needed to ensure the reliability of the system. . . . In particular, the IRM reduction is driven by a lower average Effective Equivalent Demand Forced Outage Rate (EEFORd) – the forced outage rate used for reliability and reserve margin calculations." *Capacity Reserve Needs Shrink with Increased Generator Efficiency*, PJM Inside Lines (Dec. 10, 2020), https://insidelines.pjm.com/capacity-reserve-needs-shrink-with-increased-generator-efficiency/.

[9] PJM, 2020 PJM Reserve Requirement Study at 28, Appendix B (Oct. 6, 2020). Accessed at: https://www.pjm.com/-/media/committees-groups/committees/mc/2020/20201119/20201119-cac-2-2020-installed-reserve-margin-study-results-report.ashx.

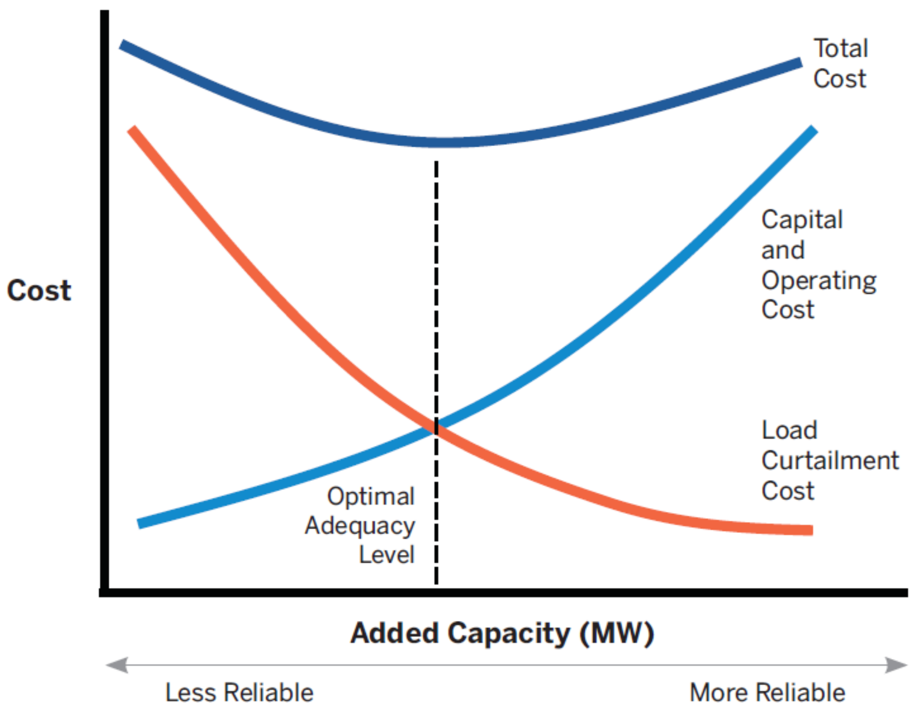
[10] Duke Response to CEBA DR4-4 (Exhibit 1 at 3) (citing NERC 2022-2023 Winter Reliability Assessment Report).

[11] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 18, 45-56, 94-123 (Oct. 2023). Accessed at: https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

Q: How does increasing the reserve margin impact consumer costs?

A: Requiring a higher reserve margin generally increases the capital costs paid by consumers, while inadequate resources resulting in load curtailment can also impose costs.[12] In the tradeoff between costs and reliability, there is an economically optimal reserve margin. However, most utilities do not establish target reserve margins by optimizing costs. Instead, they use the 1-in-10 LOLE criterion, which tends to establish reserve margins higher than the economically optimal reserve margin.[13]

Figure 1: Optional Adequacy Level as a Function of Investment Cost and Load Curtailment Damages[14]



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[12] Customers' willingness to pay for capacity resources is related to the costs they face due to load curtailment ($/MWh). This can depend on the customer type and needs, and how long an outage lasts.

[13] *See, e.g.*, The Brattle Group and Astrapé Consulting, Resource Adequacy Requirements: Reliability and Economic Implications at v (Figure ES-1: Study RTO Reliability Costs as a Function of Study RTO Reserve Margin) (Sept. 2023). Accessed at: https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.

[14] Energy Systems Integration Group's Resource Adequacy Task Force, New Resource Adequacy Criteria for the Energy Transition at 41 (Figure 13). Accessed at: https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024a.pdf.

Industry experts have asserted for some time that resource adequacy criteria should better balance cost and reliability.[15]

One way to estimate the cost of increasing resource adequacy requirements is through the Cost of New Entry (CONE), which quantifies the current, annualized capital cost of constructing a power plant. CONE varies by resource and region and can be on the order of magnitude of $100,000/MW-year for a reference CT gas plant.[16]

At $100,000 per megawatt, a five percentage point increase in the reserve margin (from 17% to 22% of forecasted demand) translates to an additional 1,831 MW of capacity by 2031 which could result in incremental costs of hundreds of millions of dollars per year. Each percentage point increase in the reserve margin could mean tens of millions of dollars more per year borne by ratepayers. DEC/DEP could better quantify the cost increases from their higher forecast, reserve margin increase, and choice of resources in their portfolios, given their information on resource addition plans and maintenance costs.

Note that even when resource adequacy requirements are based on 1-in-10 LOLE and not based on optimizing costs and willingness to pay for reliability, utilities can still maintain the same level of reliability at lower cost by sharing capacity with neighbors and procuring capacity competitively. Capacity sharing between non-RTO utilities is possible;

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[15] *Id.* at 38 ("The resource adequacy criteria should be used to establish the appropriate trade-off between reliability and cost."); *see* The Brattle Group and Astrapé Consulting, Resource Adequacy Requirements: Reliability and Economic Implications at iv-v (Sept. 2013).

[16] *See* MISO, MISO Cost of New Entry (CONE) Planning Year 2023/2024 at 11 (Oct. 12, 2022). Accessed at: https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf.
Monitoring Analytics, CONE and ACR Values – Preliminary at 2 (Jan. 21, 2020). Accessed at: https://www.monitoringanalytics.com/reports/Reports/2020/IMM_CONE_ACR_Preliminary_Report_20200121.pdf

for example, the Western Resource Adequacy Program, designed by Western Power Pool and administered by Southwest Power Pool, has been approved by FERC.[17]

Competitive procurement aside from an RTO capacity market is also possible and beneficial, for example, through all-source procurement appropriately tailored to public policy needs.

Q: How can different resources contribute to resource adequacy? How are different resources affected by weather?

A: Both supply- and demand-side resources can contribute to resource adequacy requirements. On the supply side, all resources have weather-dependent performance or seasonal risk, and this can affect how much capacity is credited to each resource type.

Historically, utilities and grid operators have assigned capacity factors to wind and solar to reflect their seasonal performance. The Astrapé Study assigns 5% of nameplate capacity to solar for the winter peak. Astrapé has also prepared reports on the Effective Load Carrying Capability (ELCC) for wind, solar, and storage.[18] ELCC determines capacity credit based in part on other resources in a portfolio. For example, ELCC may assign less credit to solar as solar accumulates on a utility's system and shifts the system net peak to times when solar is less productive.

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[17] *Western Resource Adequacy Program*, Western PowerPool, https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program (last visited at May 24, 2024); Clean Energy Buyers Association and Western Resource Advocates, Resource Adequacy in the Western Interconnection at 12-13 (Aug. 2023). Accessed at: https://cebi.org/wp-content/uploads/2023/08/CEBI_Resource-Adequacy-in-the-Western-Interconnection-August-2023.pdf.

[18] Astrapé notes that storage improves the ELCC of solar. Astrapé Study at 45. With transmission and greater sharing of resources across broader geographies, ELCC for solar would be higher because peak solar production and electricity demand would be spread across more time zones and weather patterns.

However, this kind of diminishing returns during peak periods is not unique to wind and solar resources. Fuel-dependent generation suffers correlated outages during extreme weather peaks, including during Winter Storm Elliot. The frequency of these winter outages has been highlighted in the NERC and FERC report on Winter Storm Elliot, which was the fifth such event in the last 11 years.[19]

Q: How can extreme weather impact gas-fired generation?

A: Gas generation correlated outages occur when gas wellheads, pipelines, and/or power plants cannot operate due to extreme cold weather. Thus, adding more gas to a system where gas is repeatedly experiencing outages during winter peak may contribute less to reliability during winter peak than the capacity credit that is assigned to gas using traditional accreditation methods. During warmer months, drought and extreme heat conditions can impact thermal plant cooling, which can also result in correlated outages. The graph below published by U.S. DOE shows the correlation of temperature and outages of different types of generators. [20]

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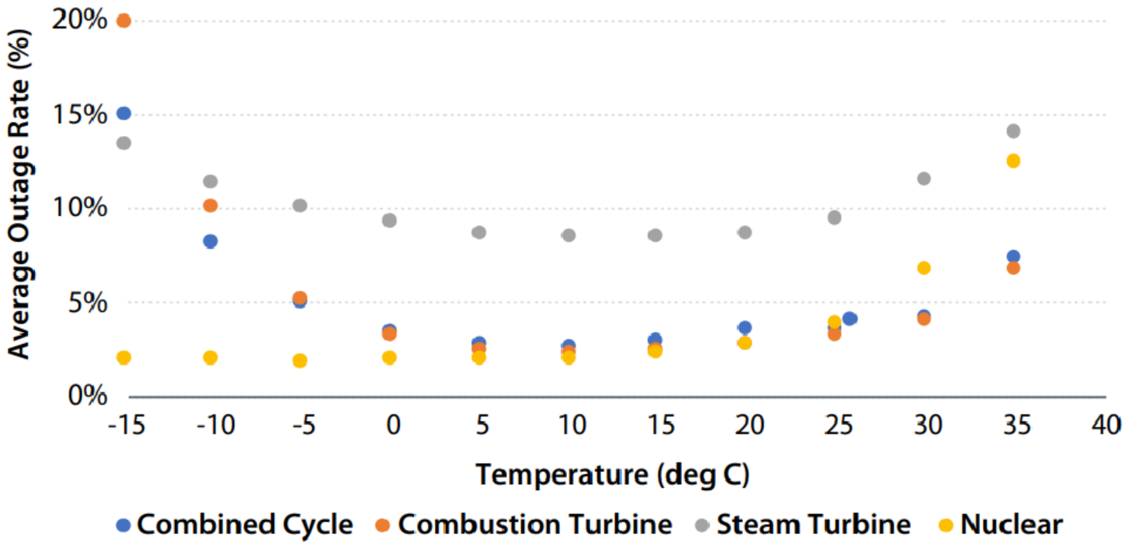
[19] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 5-6 (Oct. 2023).

[20] U.S Department of Energy, The Future of Resource Adequacy at 10 (Figure 2) (Apr. 2024). Accessed at: https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf.

Figure 2: Historical Outage Rates for Fossil and Nuclear Power Plants By Temperature



Better accounting for all resources prone to outages during certain weather conditions will improve accreditation for how much they will likely contribute to system reliability, including during extreme peaks. Many RTOs are developing means of accounting for and crediting all resources for their contributions to resource adequacy by seasons.[21] These efforts can help match procured resources to seasonal resource adequacy needs as well as appropriately compensate these resources where they are paid for performance. NREL notes this as a best practice.[22]

The Astrapé Study recommends an increase of 2.5 percentage points to the reserve margin based on data with greater outage rates from the last five years (including Winter

[21] *See* The Brattle Group, Capacity Resource Accreditation for New England's Clean Energy Transition (June 2, 2022). Accessed at: https://www.mass.gov/doc/capacity-resource-accreditation-for-new-englands-clean-energy-transition-report/download. Astrapé Consulting, Accrediting Resource Adequacy Value to Thermal Generation (Mar. 30, 2022). Accessed at: https://www.Astrapé.com/wp-content/uploads/2024/01/Accrediting-Resource-Adequacy-Value-to-Thermal-Generation-1.pdf.
[22] Lawrence Berkley National Laboratory, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems at 30-31 (June 2023).

Storm Elliot) and greater winter risk. However, many of these historical outages are avoidable with better winter preparedness, as recommended in the NERC/FERC Winter Storm Elliot report and the other reports studying previous winter fossil plant failures.[23]

Further, some of the fuel-free resources coming online as part of DEC/DEP's proposed new resource portfolios would not suffer from the same fuel-delivery outage problems. The historical outage rates used to support the proposed target reserve margin increase may not accurately reflect DEC/DEP's future fleet performance once the Companies incorporate recommendations to improve winter outages and newer generation resources that are less prone to outages come online. These improvements to fleet performance could mitigate the proposed reserve margin increase due to historical outages and winter risk while maintaining the same level of resource adequacy.

In Astrapé's modeling, some planned outages occur during loss-of-load events. With better short-term load forecasting, some of these planned outages could be scheduled for when the capacity is not needed. Including planned outages during loss-of-load events in the modeling can overestimate unavoidable outages and underestimate capacity availability during certain times.[24]

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[23] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 103-105, 131-136 (Oct. 2023).

[24] "Forced outage data is based on historical data. The planned maintenance percentage rates are based on planned data and not historical data. SERVM schedules planned outages based on the average daily peak net loads. SERVM optimizes the planned maintenance to be scheduled during off peak days. This results in no planned maintenance scheduled in the vast majority of loss of load events for DEC and DEP." Duke Response to CEBA DR4-13 (Exhibit 1 at 6).

Q: How can electricity imports and resource sharing contribute to reliability?

A: Imports and resource sharing have been critical to ensuring reliability during each extreme weather event stressing the grid. As noted by NARUC:

> Neighboring Grids and Transmission Should Be Modeled as Capacity Resources: Resource sharing can be a significant, low-cost alternative to procuring new resources. Imports from neighboring regions are likely to become more valuable for resource adequacy due to the increased diversity of chronological wind, solar, and load patterns over a much larger area. While extreme weather can happen anywhere, it does not happen everywhere at once.[25]

Winter Storm Elliott produced the largest controlled firm load shed in the history of the Eastern Interconnection. NERC and FERC noted that it was "especially disconcerting that it happened in the Eastern Interconnection which normally has ample generation and transmission ties to other grid operators that allow them to import and export power."[26]

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[25] National Association of Regulatory Utility Commissioners, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms at 44 (Nov. 2023).

[26] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 5-6 (Oct. 2023).

Figure 3: Bulk Electric System Map of Entities in the U.S. Eastern Interconnection Affected by the Extreme Cold Weather

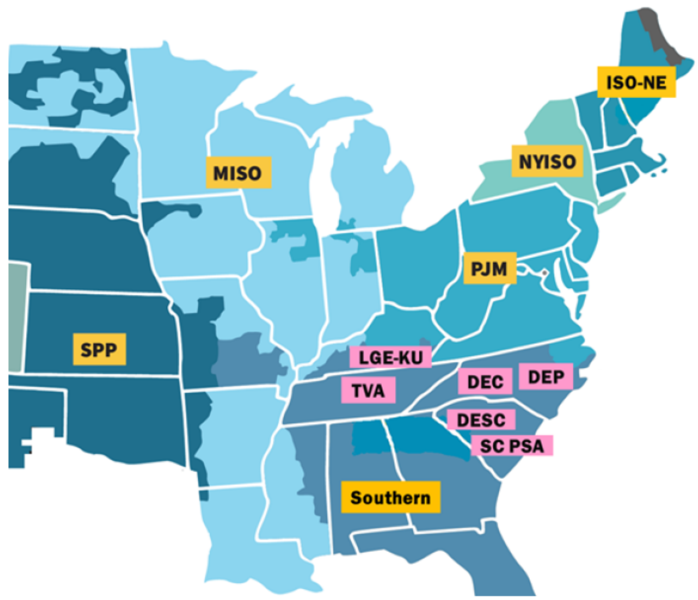


Figure 3 comes from the NERC and FERC report and "shows the entities in the U.S. Eastern Interconnection most affected by Winter Storm Elliott." RTOs and larger balancing areas did not need to shed firm load, while "[t]he entities represented by a pink box shed firm load at some point during the Event."[27] These smaller balancing areas do not have the diversity advantage of larger regions, and while DEC/DEP benefited from power purchases from PJM primarily, some non-firm purchases were curtailed.[28] Note that grid operators

[27] *Id.* at 7 (Figure 1).

[28] "[O]n December 23, Duke Energy contracted 'day-ahead' for 940 MW of firm power purchases. These purchases were primarily sourced from [PJM] for delivery on December 24. On a day-ahead and intra-day basis, Duke Energy made 370 MW of non-firm power purchases (primarily sourced from PJM) for delivery during the second half of December 23. From approximately 5:15 to 7:30 PM, DEC experienced curtailment of 300 MW from the non-firm purchases primarily sourced from PJM. On an emergency basis, Duke Energy made sales to [redacted] that began in the morning of December 23, increased throughout the day to a maximum amount of 830 MW from 7:00 to 11:00 PM, and subsequently ended early the next morning." South Carolina Office of Regulatory Staff, Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts at 9 (Aug. 25, 2023). Accessed at: https://dms.psc.sc.gov/Attachments/Matter/ec372380-8639-406e-816e-fc9fe0d45cfd. *Id.* at 35-36 (describing curtailed bilateral purchases from suppliers, including from within PJM).

tend to prioritize their own balancing areas and service to their own members and thus curtailments could be less likely if DEC/DEP were members of PJM.

Based on DEC/DEP discovery responses so far, transmission limits were not at issue in determining allowable imports into DEC/DEP during Winter Storm Elliot.[29] Thus, arrangements to bring in available power could be made without having to wait for transmission upgrades. If needed, additional transmission capacity could be made available with grid enhancing technologies like dynamic line ratings (DLR), which can increase available transmission capacity.[30]

Q: How did the Astrapé Study address electricity imports?

A: The Astrapé Study's assumption of lower neighbor assistance produced a 1.75 percentage point increase in the recommended target reserve margin from the previous resource adequacy study. Neighbors were modeled as if they only had enough capacity to meet their minimum resource adequacy requirements needed for the 1-in-10 LOLE criterion.[31]

[29] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 44 (Oct. 2023) ("DEP and DEC indicated that they had no significant transmission outage plans or outages before or during the Event."); *see also* South Carolina Office of Regulatory Staff, Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts at 44 (Aug. 25, 2023) (describing how transmission capacity was not at issue).

[30] "The [transmission] limits are set based on seasonal firm transfer capability. In general, dynamic line ratings are only used in real-time operations with the application of real-time environmental conditions and thus are not utilized in the determination of the transmission limits referenced in Section L, page 43." Duke Response to CEBA DR4-19 (Exhibit 1 at 8).

[31] "Astrapé believes in modeling the neighbors at 1-in-10 LOLE reliability so as to not overstate the reliance on neighbor assistance. It would not be prudent for the Companies to plan their system assuming TVA, PJM, or Southern Company would plan to be long capacity in order to assist the Companies during capacity shortfalls. This shortage of capacity during extreme winter periods was seen during Winter Storm Elliot. Assuming a 1-in-10 LOLE target for neighbors is reasonable and provides a way to capture the weather and generator outage diversity benefits the Companies have with their neighbors" Duke Response to CEBA DR4-14 (Exhibit 1 at 7).

However, neighbors historically have had capacity exceeding what is needed to meet this criterion, as noted by the NERC Winter and Summer Assessments, as seen below.[32]

Figure 4: NERC regions in the Southeast Neighboring DEC/DEP

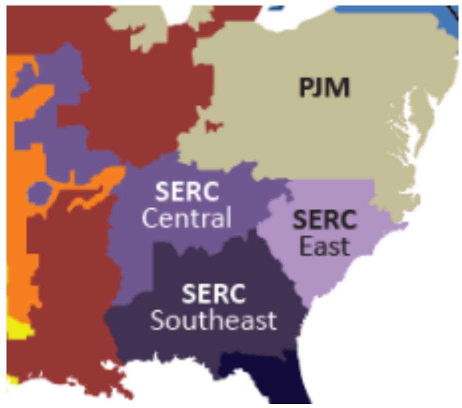
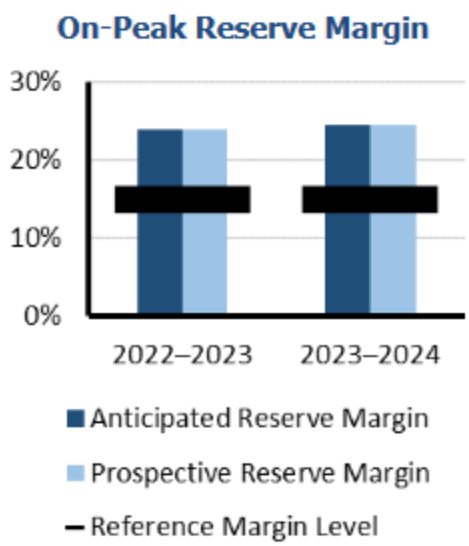


Figure 5: SERC-East (NC and SC)[33]



[32] See the Summer and Winter Assessments for each year available here: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[33] NERC, 2023-2024 Winter Reliability Assessment at 22 (Nov. 2023). Accessed at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.
Anticipated reserve margin resources include: commercially operable generation with firm capability with firm transmission and/or designated market resources; capacity under construction or has received approved planning requirements; and transfers with firm contracts. Prospective reserve margin resources include all of the anticipated resources plus generation that could be available to serve load for the period of peak demand for the season but do not meet the anticipated resource definition.

Figure 6: SERC-Central
(Tennessee and parts of Georgia, Alabama, Mississippi, Missouri, and Kentucky)[34]

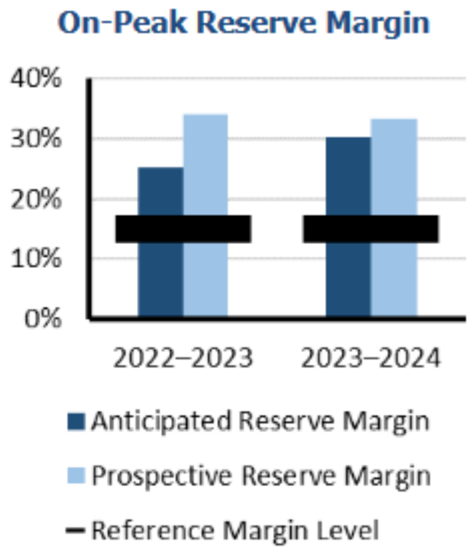
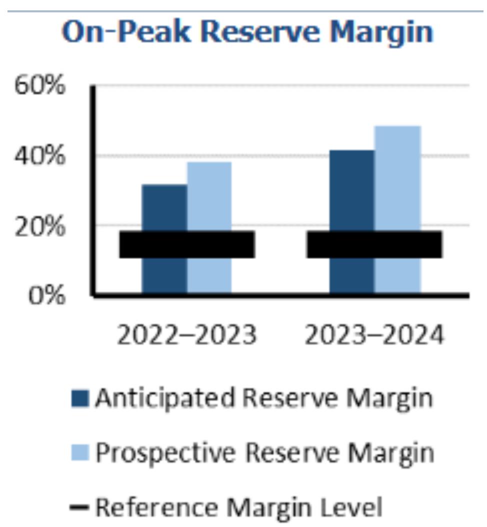
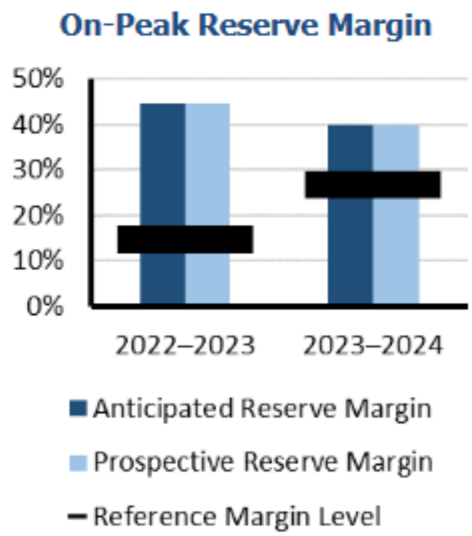


Figure 7: SERC-Southeast
(All or portions of Georgia, Alabama, and Mississippi)[35]



[34] *Id.* at 23.
[35] *Id.* at 24.

Figure 8: PJM[36]



The reduced need for new assets is one of the largest cost savings benefits to sharing resources with neighbors.[37] DEC/DEP raises wheeling concerns,[38] but there are ways to mitigate wheeling charges, such as by being a member of an RTO.

An example of a resource sharing mechanism that does not require RTO membership is the Western Resource Adequacy Program (WRAP). WRAP requires participants to demonstrate their ability to meet their peak demand plus a reserve margin in the seven months ahead of winter and summer seasons. It features an operations program to address shortfalls ahead of an operating day. Participants monitor and report their daily resource availability and demand as well as comply with dispatch instructions from the

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[36] *Id.* at 21. PJM's latest reserve requirements study recommends an Installed Reserve Margin of 17.7%, and thus the reference margin level for 2023-2024 in the graphic may be an error. PJM, 2023 Reserve Requirement Study at 19 (Dec. 29, 2023). Accessed at: https://www.pjm.com/-/media/planning/res-adeq/2023-pjm-reserve-requirement-study.ashx.

[37] *See, e.g.*, *Value Proposition*, MISO, https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/ (last visited May 24, 2024); National Association of Regulatory Utility Commissioners, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms at 95-96 (Nov. 2023).

[38] Docket No. E-100, Sub 190, 2023 Carolinas Resource Plan; Duke Response to CEBA DR4-12 (Exhibit 1 at 5).

program operator. Participants needing supply can call on resources from other WRAP participants with surplus. Southwest Power Pool acts as the program operator, as directed by Western Power Pool.[39] Initial estimates for the planning reserve margins are 9%-15% in the summer and 13%-19% in the winter to meet the 1-in-10 LOLE criterion.[40] These are lower than the target reserve margin recommended in the Astrapé Study.

While the Southeast has the Southeast Energy Exchange Market and the Southern Company Energy Auction, neither mechanism is a resource adequacy sharing program. DEC/DEP are part of the VACAR reserve sharing group, but this program is limited in geography and scale.

Assistance to states for resource sharing with neighbors to improve resilience and resource adequacy is being set up by the National Association of State Energy Officials (NASEO) with $3 million in funding from DOE. North Carolina is part of this effort. The program will include examining how state-level integrated resource planning can be coordinated with broader regional plans.[41]

Q: How can energy efficiency and demand response contribute to reliability?

A: Demand-side resources have the benefits of being co-located and coincident with load. They have shorter deployment timelines compared to traditional generation and do not face

[39] *WRAP FAQs*, Western PowerPool, https://www.westernpowerpool.org/news/wrap-faqs (last visited May 24, 2024).
[40] Western PowerPool, Western Resource Adequacy Program: Detailed Design at 128 (Mar. 2023). Accessed at: https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf.
[41] Grid Deployment Office, *Biden-Harris Administration Announces more than $10 Million to Support State Engagement and Analysis in Wholesale Electricity Markets, Reducing Costs for Consumers*, Department of Energy (Apr. 11, 2024), https://www.energy.gov/gdo/articles/biden-harris-administration-announces-more-10-million-support-state-engagement-and?auHash=yIq0PsIfO6awQSoS-klIYxAGEevWEBXgo0GfAk-PS6s&utm_medium=email&utm_source=govdelivery.

the same permitting and siting risks.[42] Grid operators may treat these resources as demand-side only, including them in the long-term load forecasts and/or providing a means of avoiding costs. However, supply-side payments to demand-side resources for capacity commitments as well as emergency services result in more demand-side resource availability.[43] For example, demand-side resources can participate in capacity markets for a chance to earn compensation. In PJM and ISO-New England, demand-side resources, including energy efficiency, accounted for around 10% of the cleared capacity in capacity auctions.[44] In PJM, energy efficiency is 5% of cleared capacity for the 2024/25 delivery year.[45]

Further, some of the load growth in DEC/DEP territory is large new loads that could be flexible if provided with the right incentives and timely information.[46] Better short-term

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[42] *See* The Brattle Group, Real Reliability: The Value of Virtual Power (May 2023); U.S Department of Energy, The Future of Resource Adequacy at 24 (Apr. 2024) ("VPPs have the potential to address 10% - 20% of peak demand by 2030 and save approximately $10B per year in grid spending nationally."); The Pathway to: Virtual Power Plants Commercial Liftoff, U.S Department of Energy, https://liftoff.energy.gov/vpp/ (last visited May 24, 2024).

[43] *See* The Brattle Group and Advanced Energy Economics, Enabling Cost-Effective Energy Efficiency in the Midcontinent ISO Resource Adequacy Construct (Apr. 2021). Accessed at: https://info.aee.net/hubfs/Enabling-Cost-Effective-Energy%20Efficiency-in-the-Midcontinent-ISO%20Resource-Adequacy%20Construct_.pdf.

[44] Ellen Foley & Matt Kakley, *New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2026/2027*. ISO New England (Mar. 10, 2023), https://www.iso-ne.com/static-assets/documents/2023/03/20230310_pr_fca17_initial_results_final.pdf; PJM, 2024/2025 RPM Base Residual Auction Results at 10 (Table 6) (Feb. 2023). Accessed at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

[45] PJM, 2024/2025 RPM Base Residual Auction Results at 10 (Feb. 2023).

[46] *See* Mehra and Hasegawa, *Supporting power grids with demand response at Google data centers*, Google (Oct. 3, 2023), https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption; Chen, Leveraging Locational and Temporal Flexibility in Transportation Electrification to Benefit Power Systems (Mar. 2023). Accessible at: https://www.esig.energy/wp-content/uploads/2023/03/ESIG-Retail-Pricing-EV-flexibility-Chen-wp-2023.pdf.

forecasting, notice, and price signals can improve the ability to call and rely on demand response.[47]

Q: How can better shorter-term forecasts improve reliability?

A: While DEC/DEP's long-term load forecasts that determine resource adequacy planning have not been low in general, the load forecast for Q3 looking ahead to Q4 when Winter Storm Elliot occurred was low.[48] For the several days prior to the event, DEC/DEP's forecasts were grossly under actual load. The two figures below are from the NERC/FERC report and show that DEC and DEP were forecasting significantly below their peers in the days leading up to the loss-of-load event.

[47] South Carolina Office of Regulatory Staff, Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts at 22-23, 44-45 (Aug. 25, 2023) (noting that DEC/DEP did not call on all of the demand response available during Winter Storm Elliot).

[48] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 30 (Figure 13) (Oct. 2023) (Figure 13 summarizes peak load forecasts in advance of the 2022-2023 winter season, typically developed during the third calendar quarter in advance of the subsequent winter, and compares the forecast against the actual peak loads that occurred within each Core Balancing Authority footprint during the Event, as well as against the estimated peak if firm load shed or demand response had not reduced the actual peak load).

Figure 10: Balancing Authorities Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual Peak Loads (Percent Difference) For December 23, 2022[49]

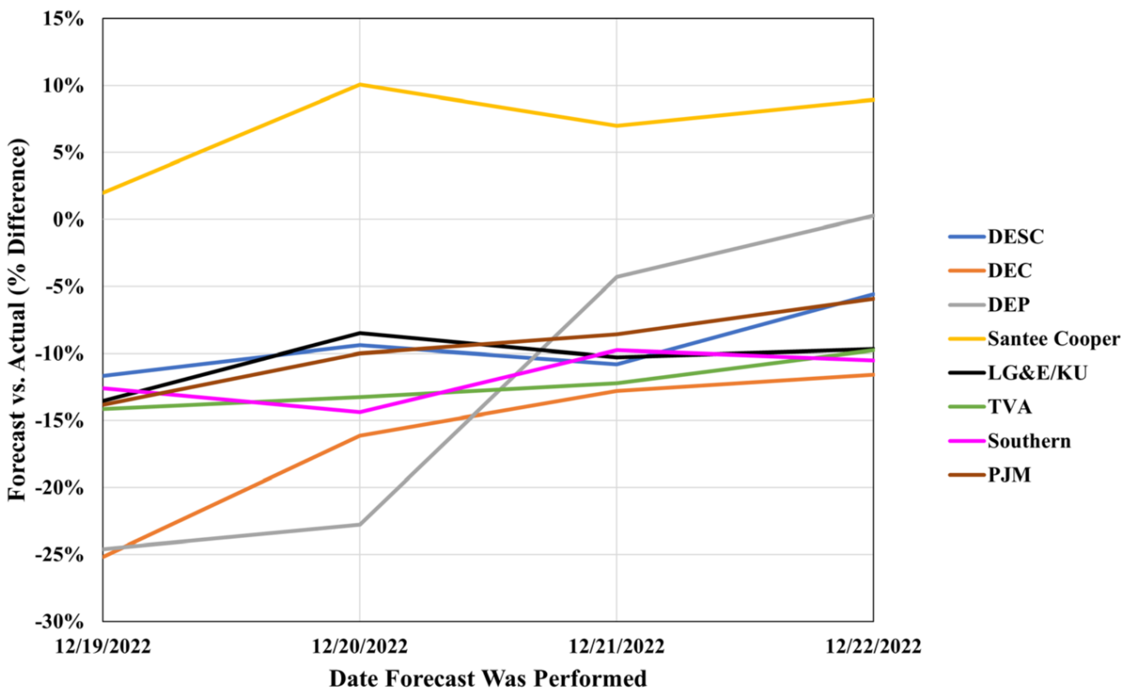
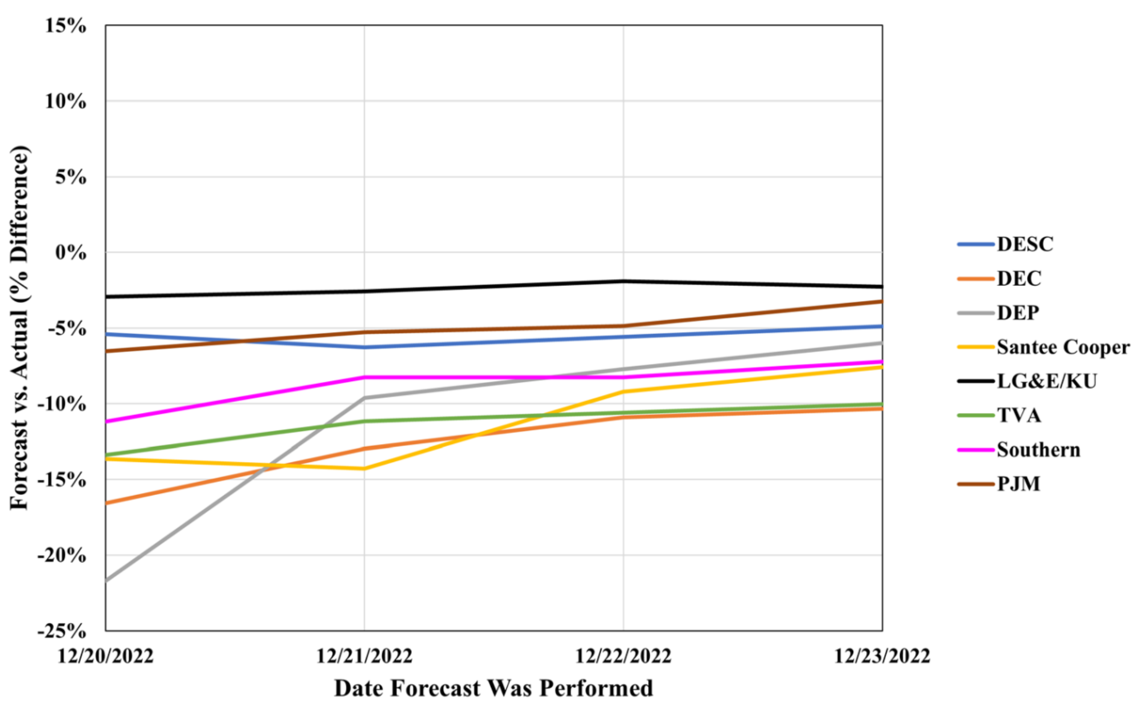


Figure 11: Balancing Authorities Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual Peak Loads (Percent Difference) For December 24, 2022[50]



By improving the quarter-ahead forecast, DEC/DEP could better anticipate and alter its planned outage scheduling to avoid scheduling outages during anticipated extreme peaks. By improving the Daily 7 Day Peak Load Forecast, which is used in calculating the forecasted daily operating reserve for the next seven days, DEC/DEP could better determine if there is a need for additional reserves in the days ahead.[51] The NERC/FERC report surveys how each balancing authority plotted in the figures above performs its forecasts and assesses accuracy.[52] It also offers some potential improvements for more accurate forecasting.[53] Some of the balancing authorities' forecasting methods produced more accurate forecasting results than others during Winter Storm Elliot. Short-term forecast improvements could improve reliability while mitigating increases to the target reserve margin.

Q: How do the assumptions and modeling in the Astrapé Study's islanding scenarios depart from real world situations?

A: The Astrapé Study's modeled scenarios are combinations of islanding: whether DEC & DEP are separate islands, whether they are one combined island, or whether they are islanded from each other but have limited connections with other neighbors. The base case, which is the basis for the reserve margin increase, has limited resource sharing across DEC,

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[51] "Request: Does the short-term forecast inform the level of operating reserves? Could there have been sufficient operating reserves during Winter Storm Elliot if the short-term forecast was accurate?
Response: Yes, each Company's Daily 7 Day Peak Load Forecast includes a daily forecast of the Balancing Authority ("BA") Peak Load for the next seven days that is used in calculating the forecasted daily operating reserve for the next seven days. The forecasted operating reserve is then compared against the established day ahead operating reserve target to determine if there is a need for additional planning reserves. The established day ahead operating reserve target is not informed by the short-term forecast." Duke Response to CEBA DR4-25 (Exhibit 1 at 10).

[52] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 42-43 (Oct. 2023).

[53] *Id.* at 146-151 (Oct. 2023).

DEP, and their neighbors. DEC and DEP are allowed to assist one another in the base case for modeling purposes, but it is not clear to what degree and whether dispatch is co-optimized as a single system.

The islanding scenarios are situations that do not occur in the real world and reflect conservative situations that would require higher reserve margins. DEC and DEP do not act as separate islands, and they are not islanded from the rest of the grid.[54] Even though these scenarios are not realistic on their own, they show how much sharing resources across borders can reduce resource adequacy requirements. As seen in the Astrapé Study, the most islanded scenarios would have produced target winter reserve margins of 28.5% (DEC) and 26% (DEP),[55] much higher than the 22% increase recommended where DEC and DEP share some resources with one another and have limited sharing with neighbors. These savings scale up as resources are more robustly shared across broader footprints with greater diversity in supply and load.

Other assumptions mentioned in the sections above that could significantly impact the recommended reserve margin include:

(1) Winter risk: The Astrapé Study assumes DEP/DEC system outages remain at historical levels despite recommended improvements and newer and fuel-free resources coming

[54] "Request: Consistent with Astrapé's approach of looking at historical data and trends for the past 5 years, have there been cases where DEC and DEP have acted as separate islands from each other as modeled?
Response: No. As outlined in the 2023 Resource Adequacy Study, the Combined scenario where DEC and DEP prioritize assisting each other and have access to a majority of all SEEM members is considered the Base Case and reflects how the DEC and DEP systems are actually operated. The additional cases including the island, combined island, and individual interconnected scenarios are also considered in order to quantify the reserve margin benefit from both the prioritization of helping each other as well as the benefit of having access to neighboring regions which provide weather and generator outage diversity." Duke Response to CEBA DR4-6 (Exhibit 1 at 4).
[55] Astrapé Study at 4.

online. Further, the model does not always reflect grid operators' ability to schedule planned outages around system outages as short-term forecasts are improved.

(2) Neighbor assistance: The Astrapé Study assumes neighbors only have the bare minimum capacity to meet the 1-in-10 LOLE criterion, rather than using actual historical levels or projected future capacity availability. As seen in NERC resource adequacy assessments, however, neighbors all have capacity exceeding what is needed to satisfy the 1-in-10 LOLE criterion and are planning on increasing capacity further.

Q: Is there a clear conceptual explanation for the 0.75 percentage point target reserve margin increase from the change in the economic load forecast error distribution in the Astrapé Study?

A: The Astrapé Study, clarified by Duke's response to CEBA DR4-20, noted that the 2020 economic load forecast error distribution model weighed over-forecasting more than under-forecasting load, while the 2023 study used a more symmetrical distribution. The 2020 version used historical data, while this new distribution looks forward. But aside from the mention of a change of methodology, there has been no clear conceptual explanation provided for why the updated economic load forecast error distributions represent near symmetrical probabilities for over and under forecasting in the 2023 Resource Adequacy Study with a slight skew towards under-forecasting load growth in the future. This is in contrast to error distributions seen in the past.[56] There is also no explanation about how the new methodology will produce better forecast error distributions. This change adds a 0.75

[56] The Direct Testimony of Richard Nichols Wintermantel and Cole Michael Benson at 15-17 similarly does not make clear what are assumptions versus modeled results. Is it mostly assumed that future forecasting produces results that would equally over- and under-forecast whereas in the past most utilities' long-term forecasts tended to be over? How is the forecast error determined in the future if there are not yet actual numbers with which to compare the forecasts?

percentage point increase to the recommended target reserve margin. While 0.75 percentage points may seem insignificant, it translates to an increase of 275 MW based on the 2023 fall update forecast, which could result in tens of millions of dollars of additional ratepayer costs per year.

Q: How could DEC/DEP model the system beyond the scenarios presented in the Astrapé Study to better understand different options for maintaining reliability in a cost-effective way?

A: The Astrapé Study recommends increasing DEC/DEP's reserve margin from 17% to 22%, based on conservative assumptions and choices on whether to use historical data or not in a way that leads to higher target reserve margins. First, the Astrapé Study only includes islanded scenarios that are more conservative than the real world in terms of resource sharing between neighbors. Second, the Astrapé Study assumes minimum resource adequacy levels for DEC/DEP's neighbors, not their historical reserve margins that are in excess of what they need to meet the 1-in-10 LOLE criterion. The Astrapé Study uses historical outage rates, that may not reflect improvements to fleet turnover, performance, and scheduling in the future. Instead of using an error distribution that reflects historic over-forecasting for long-term economic, Astrapé is implementing new error distributions that look forward.

If the goal is to investigate what actions could help maintain reliability at lower cost, we could view the Astrapé Study from a different angle. It appears that addressing historic winter outages and risk could significantly reduce the need to increase the reserve margin and thus overall costs. Astrapé could model the impact of eliminating preventable planned or forced outages during loss of load events (whether from better short-term forecasting or better maintenance and weatherization) from the historical data set on the target reserve margin. This could include implementing NERC and FERC's winter preparedness recommendations.[57]

Astrapé could add scenarios and assumptions that reflect additional resource sharing to model the savings. This could include modeling the impacts of actual and projected reserve margin levels of neighbors (*e.g.*, as documented in NERC assessments) as well as scenarios where DEC/DEP is part of a regional resource adequacy program or RTO.

Other scenarios could include additional participation from demand-side resources at the levels seen in PJM or ISO-New England. These resources could be incentivized through payments for capacity commitments, performance incentives, and better notice and price signals before and during loss-of-load events. Quantifying the cost of increasing the reserve margin can help estimate the value of programs that reduce demand during peak periods.

Q: Does this conclude your testimony at this time?

A: Yes.

[57] FERC, NERC, and Regional Entity, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott at 103-105, 131-136, 45-56, 94-123 (Oct. 2023); *id.* at 146-151 (description of short-term forecast improvements and better coordination with neighbors).

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

How much additional capacity in MWs does the higher load forecast and recommended reserve margin translate to?

Response:

From SPA Table 2-6 DEC has a projected System Winter Peak Load of 21,120 MW in 2031. A 17% winter planning reserve margin results in 3,590 MW of firm winter reserve capacity above the weather-normal projected winter peak. A 22% winter planning reserve margin results in 4,646 MW of firm winter reserve capacity above the weather-normal projected winter peak. The difference in firm winter reserve capacity required under a 22% winter planning reserve margin compared to a 17% winter planning reserve margin is 1,056 MW.

From SPA Table 2-7 DEP has a projected System Winter Peak Load of 15,504 MW in 2031. A 17% winter planning reserve margin results in 2,636 MW of firm winter reserve capacity above the weather-normal projected winter peak. A 22% winter planning reserve margin results in 3,411 MW of firm winter reserve capacity above the weather-normal projected winter peak. The difference in firm winter reserve capacity required under a 22% winter planning reserve margin compared to a 17% winter planning reserve margin is 775 MW.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

How much additional cost does this additional reserve margin translate to given DEC/DEP's rising load forecasts and proposed resource mix?

Response:

The Companies have not quantified the additional cost from the increase in winter planning reserve margin relative to the impacts of the load forecasts analyzed in the CPIRP and its resulting impact to resource selection.

Responder: Michael T. Quinto, Director, IRP Advanced Analytics

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

What was DEC/DEP's actual reserve margin in 2022 (not the recommended reserve margin of 17% from the 2020 study)? Is this consistent with NERC reports for SERC-East for 2022?

Response:

DEC's weather normal projected reserve margin for the winter of 2022-2023 was approximately 25%. DEP's weather normal projected reserve margin for the winter of 2022-2023 was approximately 18%. The NERC 2022-2023 Winter Reliability Assessment report issued in November 2022 projected a weather normal On-Peak Reserve Margin for the SERC-East Region (North and South Carolina) of approximately 24%. See attached "NERC 2022-2023 Winter Reliability Assessment Report."

NERC 2022-2023
Winter Reliability Ass

Responder: Tiffany Weir, Rates & Regulatory Filings

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Consistent with Astrape's approach of looking at historical data and trends for the past 5 years, have there been cases where DEC and DEP have acted as separate islands from each other as modeled?

Response:

No. As outlined in the 2023 Resource Adequacy Study, the Combined scenario where DEC and DEP prioritize assisting each other and have access to a majority of all SEEM members is considered the Base Case and reflects how the DEC and DEP systems are actually operated. The additional cases including the island, combined island, and individual interconnected scenarios are also considered in order to quantify the reserve margin benefit from both the prioritization of helping each other as well as the benefit of having access to neighboring regions which provide weather and generator outage diversity.

Responder: Tom J. Davis, Principal Planning Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Astrape Table 2 and 3 shows that the SEEM footprint with AECI adds significant load diversity and the system is 2.1% to 3.6% lower than system peak when DEC/DEP is at peak. If firm contracts with neighbors and transmission were available, how much assistance would that diversity translate to during DEP/DEC peak? How would that change the recommended reserve margin?

Response:

Duke Energy objects to this request to the extent it refers to "firm contracts with neighbors and transmission" as vague and ambiguous.

Notwithstanding this objection, the Companies state that the diversity with AECI and other neighbors is already captured in the Base Case modeling. If a firm purchase was made with AECI and firm transmission was available, then Astrapé expects the reserve margin would likely increase slightly because there would be less non-firm purchases available for market assistance during peak periods. This is because the non-firm purchase would become firm and make-up part of the 22% required reserve margin, and thus there would be less available non-firm to be used in the simulations. Furthermore, AECI has a peak load of approximately 5 GW and is two transmission wheels away so it isn't expected to drive the reserve margin study results significantly.

Responder: Tom J. Davis, Principal Planning Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

In the modeling, the historical outage data includes planned outages. Could some of these planned outages be scheduled for when the capacity is not needed, particularly as short-term load forecasts are improved? If so, does including these planned outages in historical outage data overestimate outages and underestimate capacity availability during certain times? In other words, does SERVM include the grid operator's ability to schedule planned outages around events? How large of an impact is that on the resulting recommended reserve margin?

Response:

Forced outage data is based on historical data. The planned maintenance percentage rates are based on planned data and not historical data. SERVM schedules planned outages based on the average daily peak net loads. SERVM optimizes the planned maintenance to be scheduled during off peak days. This results in no planned maintenance scheduled in the vast majority of loss of load events for DEC and DEP.

Responder: Tom J. Davis, Principal Planning Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Each neighbor was modeled assuming they are at their 1-in-10 LOLE, but actual reserve margins are typically much higher than that. Consistent with your use of historical data, could you please model a scenario using neighboring capacity at historical levels? What would the results be? (Section L, Astrape)

Response:

Duke Energy objects to this request as it would require original work.

Notwithstanding this objection, Astrapé believes in modeling the neighbors at 1-in-10 LOLE reliability so as to not overstate the reliance on neighbor assistance. It would not be prudent for the Companies to plan their system assuming TVA, PJM, or Southern Company would plan to be long capacity in order to assist the Companies during capacity shortfalls. This shortage of capacity during extreme winter periods was seen during Winter Storm Elliot. Assuming a 1-in-10 LOLE target for neighbors is reasonable and provides a way to capture the weather and generator outage diversity benefits the Companies have with their neighbors.

Responder: Tom J. Davis, Principal Planning Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Also in reference to Section L, could you please specify how the transmission limits are set? For example, are these transmission limits static, seasonal, or dynamic? What would be the result if you used dynamic line ratings?

Response:

The limits are set based on seasonal firm transfer capability. In general, dynamic line ratings are only used in real-time operations with the application of real-time environmental conditions and thus are not utilized in the determination of the transmission limits referenced in Section L, page 43.

Responder: Jack W. Armstrong, Initiative Management Manager

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Was the long-term forecast error under the actual demand for the period covering Winter Storm Elliot? For example, if Duke performs its forecasts three years in advance, what was the forecast three years before the period covering the 2022 Winter Storm Elliot event?

Response:

Please refer to the material the Companies provided to Public Staff DR3-7. After normalizing for weather, the DEP system peak was 399 mw (2.8%) below the forecast that appeared in the 2018 IRP, while the DEC system peak was 57 MW (0.3%) below the forecast from the 2018 IRP. In both cases, the recorded peak exceeded the forecast peak, which was computed using what was calculated as normal weather at the time the forecast was made.

Responder: Benjamin W. Passty, Principal Load Forecasting Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Does the short-term forecast inform the level of operating reserves? Could there have been sufficient operating reserves during Winter Storm Elliot if the short-term forecast was accurate?

Response:

Yes, each Company's Daily 7 Day Peak Load Forecast includes a daily forecast of the Balancing Authority ("BA") Peak Load for the next seven days that is used in calculating the forecasted daily operating reserve for the next seven days. The forecasted operating reserve is then compared against the established day ahead operating reserve target to determine if there is a need for additional planning reserves. The established day ahead operating reserve target is not informed by the short-term forecast.

Duke Energy objects to this data request on the grounds that it calls for speculation and requests information that is outside the scope of the issues to be decided in this proceeding and therefore is not reasonably tailored to lead to the discovery of admissible evidence. Subject to and without waiving its objections, on December 22, 2023, the Commission issued its Order Making Findings and Directing Actions Related to Impact of Winter Storm Elliott in Docket No. M-100, Sub 163 in which it established a Winter Reliability Assessment docket and a Gas-Electric Coordination docket and directed Duke Energy to report on certain items related to Winter Storm Elliott and the Companies' general procedures for winter preparedness as well as to file concurrently with the Commission Duke Energy's reports to NERC and FERC on winter preparedness and extreme weather events. The Companies expect that the information requested by this data request may be covered by one or more of those reports, which are currently in the process of being prepared. In addition, the Companies incorporate by reference and reiterate information submitted to the Public Staff in discovery and filed publicly in Docket No. M-100, Sub 163 as well as information presented to the Commission during the January 3, 2023 briefing and the September 26, 2023 Technical Conference.

Responder: Tiffany Weir, Director, Rates & Regulatory Filings

CERTIFICATE OF SERVICE

The undersigned for Clean Energy Buyers Association hereby certifies that she served the foregoing Direct Testimony and Exhibit upon the parties of record in this proceeding by electronic mail as set forth in the Service List for such docket maintained by the NCUC Chief Clerk's Office.

This 28th day of May, 2024.

/s/ Alicia Zaloga
Alicia Zaloga