UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Capacity Market Forum	**)**	**Docket No. AD23-7-000**

POST-FORUM COMMENTS OF THE SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, AND EARTHJUSTICE

The Sierra Club, Natural Resources Defense Council, and Earthjustice (Public Interest Organizations or "PIOs") appreciate the opportunity to submit these post-forum comments pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commission") June 30, 2023, Notice of Request for Comments to the June 15, 2023, forum held at FERC to discuss the PJM Interconnection, L.L.C. ("PJM") capacity market.

For the capacity market to continue to serve its role of ensuring resource adequacy, deep changes are needed to capacity accreditation and the annual procurement structure. PJM must also ensure robust measures to hold generators accountable, without subjecting generators to obligations unrelated to the assumptions underlying their capacity values. Rather than scolding state and federal policymakers for instituting critical environmental and public health protections with compliance dates a decade away, PJM's focus must be on ensuring that its markets—capacity and otherwise—are sending accurate price signals, and that PJM lowers barriers to new entry within its control, such as its severely backlogged interconnection queue. We look forward to engaging with PJM and at the Commission on future reforms to the capacity market, as well as transmission and other market reforms that are necessary to ensure reliability with both the existing and future resource mixes.

1. **The forum revealed broad support for the current structure of the capacity market but identified many needed areas of reform.**

At the forum, there was a general agreement among speakers that the capacity market does not need a fundamental overhaul and that, despite varying perceptions of its shortcomings, the existing market is better than alternative approaches for resource adequacy in the PJM region. For example, speakers noted that a centralized market design, rather than individual load-serving entities bilaterally procuring capacity to meet their own requirements, is a better fit for the many PJM states that have implemented retail choice. At the same time, speakers noted that the PJM market facilitates bilateral transactions and enables load-serving entities to opt out of the capacity market if doing so is more consistent with state regulatory frameworks or better meets other objectives.

As for necessary reforms, nearly all speakers mentioned the need for updates to capacity accreditation to ensure that contributions to resource adequacy are measured as accurately as possible. We agree that such reforms are fundamental to a functioning capacity market and discuss this topic further below. Some speakers expressed concern about capacity shortfalls, including inaccurate statements that the market is currently short of capacity.[1] A simple fact check shows this to be incorrect. PJM reports that its most recent Base Residual Auction ("BRA") resulted in a reserve margin of 20.4%, which is 5.7% above the target reserve margin

[1] Final Transcript of June 15, 2023 PJM Capacity Market Forum, AD23-7, at 82:18-19 (G. Thomas: "There is no over procurement problem in PJM, it's just the opposite right now.").

of 14.7%.[2] This excess reserve margin is consistent with prior years, in which PJM has routinely procured far more capacity than needed to meet its target."[3]

However, this generous reserve margin has concealed some reliability risks arising from what appears to be underestimation of the risk of large-scale failures of fossil fuel plants, primarily gas-fired plants. Recent analysis by PJM staff finds that gas combined cycle units actually have a capacity value of 83% of nameplate,[4] when accounting for the historical pattern of fleet-wide failure during winter emergencies. However, PJM currently provides a far higher capacity rating of 96.9% for its 62.4 GW combined cycle fleet, based on their average 3.1% outage rate.[5] While these figures are preliminary and may change as PJM refines its approach to winter risk modeling in response to stakeholder feedback, they suggest a material overestimation of the reliability value of gas facilities under the status quo—as much as 8.7 GW of phantom capacity in RPM due to the market's current inability to account for correlated outages of combined cycle gas power plants.[6] Not only does this phantom capacity paint a false reliability picture, it contributes to the recently low capacity clearing prices that these same generators most vocally complain about.[7] PJM's Reliability Pricing Model ("RPM") simply will not function

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[2] PJM, *2024/2025 Base Residual Auction Report*, at 2 (Feb. 2023), available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-planning-period-parameters-for-base-residual-auction-pdf.ashx.

[3] *See* Jim Wilson, *Maintaining the PJM Region's Robust Reserve Margins* at 4 (May 2023), available at https://www.sierraclub.org/sites/www.sierraclub.org/files/2023-05/Wilson%20R4%20Report%20Critique%2005-02-23.pdf; *see also* PJM Annual BRA reports, available at https://www.pjm.com/markets-and-operations/rpm.

[4] PJM, *Capacity Market Reform: PJM Proposal*, at slide 61 (July 2023), available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx.

[5] PJM Resource Adequacy Planning, *2022 PJM Reserve Requirement Study*, at 31 (Oct. 2022), available at https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx.

[6] This 8.7 GW is approximately the same as the excess capacity that cleared in PJM's Base Residual Auction for 2024-2025. *Compare* 2024-25 BRA Planning Parameters (noting a Reliability Requirement adjusted for FRR obligations of 132,056 MW), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-planning-period-parameters-for-base-residual-auction-pdf.ashx, *with* 2024-25 BRA Results (stating that 140,145 MW cleared the auction), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

[7] *See, e.g.*, *Scenario Analysis for Base Residual Auction* (August 2023), at Scenarios 4 and 8 (showing that removing 6 GW of capacity would have raised prices by 94% to 850%, depending on location), available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-scenario-analysis-for-

without correct accreditation of gas power plants. Bad capacity drives out good. RPM can send the correct price signals to attract and maintain sufficient supply, but only if generators are prevented from selling capacity they can't deliver.

Finally, several speakers expressed concerns about reliability in PJM that cannot be addressed through the capacity market. For example, new resource construction may be delayed by permitting and siting obstacles, and the gas supply industry may be incapable or unwilling to operate as flexibly as needed to meet grid needs.[8] These dynamics are part of the context in which the capacity market works and point to the market's inherently limited role in the overall reliability picture. Neither PJM nor the Commission should attempt to address all reliability issues through the capacity market. Instead, PJM and the Commission should continue important ongoing work on transmission and interconnection reform, as well as improvements to energy and ancillary service markets to ensure robust compensation for the energy that consumers actually need.

2. PJM does not face a policy-driven resource retirement crisis.

Some discussion at the forum arose from PJM's February 2023 report, *Energy Transition in PJM: Resource Retirements, Replacements, and Risks*, which suggests that retirements may outpace entry of new supply resources over the next seven years. While the question posed in this report is important, the report itself is a poor foundation for any discussion because it ignores key mechanisms—including the capacity market's fundamental role in sending price signals—that help to balance the pace of retirements and replacements. This flaw is discussed in detail in

bra.ashx. Note that removal of 6 GW of supply raises prices in some regions to above the level the coal industry panelist stated is necessary for coal units to economically comply with the EPA's ozone transport rule. Tr. at 144:23.

[8] *See, e.g.*, Tr. at 94:10-24 (T. Snitchler noting siting and permitting obstacles); *id.* at 111:4-13 (M. Phillips noting pipeline operational restrictions and nomination timelines); *id.* at 117:2-12 (T. Snitchler noting gas pipeline notification periods).

a report authored by James Wilson, submitted into the record in this matter prior to the forum.[9] PJM President Manu Asthana reflected during the forum that PJM's markets could help reverse the 3 GW of economic retirements predicted in the report and help incentivize new entry.[10] Yet PJM's report—which it continues to cite in discussions with federal and state policymakers—ignores this role of its markets in ameliorating the very situation it warns of.

President Asthana suggested that PJM needed "policy relief" in the form of more flexible deadlines for retirement and declining emission targets.[11] Interestingly, PJM's report ignored the flexibility that does exist in state policies that contribute to retirements in its report. For example, in a later-published Frequently Asked Questions document, PJM acknowledged that it did not consider the "reliability safety valves" in multiple state and federal regulations, "as they mainly address timing of retirements to maintain reliability," rather than permitting "unlimited retirement deferral."[12] This explanation is perplexing, considering that the timing of entry and exit was precisely the focus and alleged concern of PJM's report. It also precludes deeper dialog about what kind of flexibility PJM would find necessary, and whether that degree of flexibility is at all compatible with the urgent environmental, public health, and community investment objectives that states seek to achieve with these regulations. Finally, we note that the flexibility PJM seeks actually risks undermining the signal for new entry.[13] Identifying in advance the deadline on which generation will exit (or face increased costs) sends a clear signal to those

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[9] *See* Opening Statement of Casey Roberts, Senior Attorney, Sierra Club, at Attachment B, James F. Wilson, *Maintaining the PJM Region's Robust Reserve Margins: A Critique of the PJM Report: Energy Transition in PJM: Resource Retirements, Replacements and Risks* (May 26, 2023).
[10] Tr. at 53 (M. Asthana).
[11] *Id.* at 40.
[12] PJM, *Resource Retirements, Replacements & Risks, Frequently Asked Questions* (Apr. 21, 2023), at Question No. 11, available at https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230328-special/resource-retirements-replacements-and-risks-faq.ashx.
[13] Tr. at 147:3-11 (J. Wilson noting that state and federal policies provide years of notice regarding lead times, which the market has shown itself able to respond to without significant swings in prices).

developing new generation about when their resources will be needed. If those deadlines are muddled, developers may instead choose to wait and see whether their resource will be needed, thus worsening the new entry timing concerns that PJM's report focuses on. Rather than advocating for less stringent state climate policies, PJM should focus on refining its markets to send more effective price signals and addressing the barriers to entry within its control. As CAPS Executive Director Greg Poulos noted, "consumers want PJM to focus on developing and running a capacity construct, not on preserving certain resources."[14]

The forum also featured some overheated concerns about environmental regulations driving the retirement of broad swaths of the current generation fleet to the detriment of reliability, such as assertions that the U.S. Environmental Protection Agency's ("EPA") recently proposed rule to address carbon emissions under Section 111(d) of the Clean Air Act will cause massive coal retirements by 2030.[15] While EPA's Section 111(d) rule would require existing coal plants to achieve a 90% capture of carbon emissions if they plan to operate past 2039, the rule features numerous exceptions.[16] For instance, plants that cease operation by 2032 will be exempt from any new emission limitations. Plants that cease operation by 2035 can avoid application of new emission limitations if they operate at no more than 20% capacity.[17] These time frames—roughly a decade or more out—are more than adequate to accommodate resource adequacy needs while new resources come online. The Commission will explore the reliability impacts of EPA's proposed Section 111(d) rule at its November 9, 2023, technical conference in

[14] *Id.* at 30.
[15] *Id.* at 72-74 (M. Bloodworth).
[16] U.S. EPA, *Fact Sheet, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule*, at 6, available at https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf.
[17] *Id.* at 7.

greater detail,[18] and should avoid prejudging the issue based on incomplete and alarmist characterizations of the rule.

In any case, coal plants are far from a panacea for reliability. Coal plants are known for their inflexibility, and their lengthy start up times can significantly limit their contributions to reliability when tight grid conditions arise on short notice. And while coal plants may not be subject to the same fuel supply issues as gas plants, they nevertheless face operational problems of their own, as PJM saw during Winter Storm Elliott when over 10 GW of coal units were on forced outage for a sustained period of time due to boiler problems, tube leaks, and other plant equipment issues.[19]

Of course, any projections of resource adequacy must look not only at the pace of retirements, but also of new entry. PJM's report paints a rather pessimistic picture of new entry, despite asserting that its recent interconnection queue reforms would enable it to process sufficient new entry to meet the report's "High New Entry" scenario. In that report, PJM suggested that new resources that have already cleared the interconnection queue and have signed interconnection service agreements are not moving forward with construction.[20] However, as Abby Hopper, Executive Director of Solar Energy Industries Association, noted during the forum,[21] recent analysis from the Rocky Mountain Institute shows that relatively few of the 38 GW of projects with signed interconnection agreements are behind schedule or significantly delayed.[22] First, the median time since these 38 GW of projects signed ISAs is only

[18] 2023 Annual Reliability Technical Conference, AD23-9-000, https://ferc.gov/news-events/events/2023-annual-reliability-technical-conference-11092023.
[19] PJM, *Winter Storm Elliott Event Analysis and Recommendation Report* (Jul. 17, 2023), at Fig. 32.
[20] PJM, *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (Feb. 2023) at 19.
[21] Tr. at 93:20-25.
[22] Claire Wayner, *Analysis of PJM Interconnection Queue Projects with Signed ISAs* (Jul. 2023), https://rmi.org/wp-content/uploads/2023/07/pjm_queued_projects_isa_analysis_v3.pdf.

8 months—hardly an adequate amount of time to judge them collectively as delayed.[23] Of the 38 GW, only about 20% of clean energy projects are past their projected in-service date, whereas about 34% of natural gas projects are behind schedule.[24] Given that many of these projects had to wait for a significant amount of time in the interconnection queue—the clean energy projects waited on average 60% longer than the natural gas projects[25]—it is not surprising that some projects are not ready to immediately begin construction. PJM should engage in constructive discussions with project developers and other siting and permitting authorities to better understand the issues affecting the timeline for project development. As part of this effort, PJM should also seek to understand how lengthy wait times in the interconnection queue can contribute to later delays in development.

Finally, we note that PJM stakeholders have just begun a process to examine ways to improve the efficiency of capacity interconnection right transfers. Such transfers have the potential to better align entry and exit, while enabling new resources to leverage available tax credits and low-interest loans for reinvestment in existing energy communities.

3. Gas supply limitations must be reflected in accreditation and risk modeling.

The primary cause of reliability issues during both Winter Storm Elliott and the 2014 Polar Vortex was mechanical problems at fossil-fuel fired power plants.[26] During those two events, gas supply issues were responsible for only 23% and 11% of unavailable MW,

[23] *Id.* at 13.
[24] *Id.* at 12.
[25] *Id.* at 15.
[26] *See* PJM, *Winter Storm Elliott: Event Analysis and Recommendations Report* (July 17, 2023), at 50 ("As with other resource types, outages on gas units were primarily attributed to physical plant issues…"); *see also* PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, at 24-25 (May 2014).

respectively.[27] Maintenance failures—not gas supply limits—primarily drove emergencies on those days.[28]

Nonetheless, the 11 GW of outages caused by gas supply issues during Elliott is significant. Few, if any, of these outages were due to failures of FERC-jurisdictional gas infrastructure. Physical gas supply shortfalls were overwhelmingly caused by freezing issues at wellheads.[29] Of the nine pipelines serving PJM generators that reported higher risk of, or actual, delivery curtailments during Winter Storm Elliott, seven reported upstream supply loss.[30] There is little evidence that problems with the interstate gas delivery system play a role in current reliability problems. What assertions panelists made regarding the gas delivery system were generally speculative and related to the ability to attract investment for pipelines in support of hypothetical future gas plants.[31]

a. The Capacity Market Must Fully Consider Gas Physical and Commercial Limitations.

Natural gas suppliers often require buyers to nominate their purchases well in advance, sometimes as far as four days in advance.[32] Even after nomination, there may be delays of hours before gas arrives at the plant.[33] This has the effect of reducing potentially fast-acting gas plants to slow-start facilities. These delays have significant reliability impacts. PJM reports that gas

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[27] *Id.*

[28] *See, e.g.*, Tr. at 127:3 (J. Bowring: "A relatively small part of the total problem was gas supply. If the gas supply just hadn't occurred -- or had occurred, and that was all we had seen, we would not have had Elliott, we would not have PAI would not have had an issue. A large part of it was the units failing. Units failing to weatherize, units failing to have tested, all that basic stuff…there's no excuse for that.").

[29] *Id.* at 61-62.

[30] PJM *Winter Storm Elliott: Event Analysis and Recommendations Report*, at 21-22.

[31] *See, e.g.*, Tr. at 39, 67 (J. Bowring), & 123 (A. Keech).

[32] Tr. at 114:17 (M. Bloodworth).

[33] Tr. at 111:6 (M. Phillips).

plants that were not scheduled day-ahead had an outage rate during Elliott eight times higher than those that were.[34]

From the capacity market perspective, this is ultimately an accreditation problem: if gas plants require long notification times, their capacity value should be adjusted as it would be for any technology, as discussed further in the accreditation section below. While this accreditation may not correct operational issues arising from the lack of gas-electric coordination, it at least addresses the resource adequacy risks the coordination issues create. Ideally, the reduction in capacity revenue will encourage power plants to push for gas supply arrangements more suitable to the needs of the electricity system. In any event, the current approach of ignoring reliability effects of gas scheduling simply transfers the consequences of gas suppliers' commercial practices to consumers, leaving little incentive for industry reform.

Natural gas plants may have "firm" or "non-firm" supply arrangements. These arrangements make a difference in how likely the plant is to have fuel during emergencies.[35] The specific pipeline on which a resource is located, or where on that pipeline a resource sits, may also affect fuel availability.[36] Again, the capacity market may not be able to control these factors, but must take them into account in resource accreditation. Failure to incorporate fuel arrangements into accreditation creates a race to the bottom, as plants with the lowest-quality fuel contracts benefit from the average reliability supported by plants with firm fuel. Factoring

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[34] *See also id.* at 110:17 (M. Phillips: "Units that had day ahead awards got their gas. Units that didn't couldn't get gas.").

[35] *See* PJM, *Winter Storm Elliott: Event Analysis and Recommendation Report*, at 59 ("gas units with firm and non-firm fuel supply arrangements experienced forced outage rates of 13.8% and 33.9%, respectively"). Some market participants have expressed the view that firm fuel arrangements offer little additional value given nomination cycles—i.e., that even generators with firm fuel contracts may be unavailable if called with less than 24 hours' notice. This dynamic points to the importance of considering operating parameters in accreditation, as discussed in Section 4.b, below. It does not mean that firm fuel arrangements have no additional value from a resource adequacy perspective.

[36] Tr. at 118:9 (G. Thomas).

into accreditation the pipeline from which a plant takes gas is also vital for reliability: the system obviously should not rely on power plants added to a fully subscribed pipeline, yet that is exactly what can occur now.

b. Correct Capacity Market Price Signals are a Prerequisite to Addressing Gas Infrastructure Needs.

Several panelists noted the longer-term challenge regarding investment in the gas system.[37] While PIOs do not agree with other panelists that the need for additional pipelines has been demonstrated, correct capacity market price signals are a no-regrets solution that should be considered necessary to identify and incent investment.

Failure to implement the accreditation reforms discussed in the previous section will inhibit investment in gas infrastructure. Reforms to account for gas supply inflexibility and unreliability address situations where gas plants currently receive full capacity revenue even when required investments have not been made. If this situation is not remedied, it reduces the incentive for power plants to demand, or pipeline developers to make, investments in more reliable gas service. As Panelist Robb stated, "[m]arkets typically don't reward firm fuel contracts. Yet that may be one of the keys to our ability to expand the gas system to support the needs of the electric sector."[38] Identical capacity payments to gas plants with firm or interruptible contracts prevent proper compensation for the reliability value of firm contracts. Bad capacity drives out good.

Considering gas supply in accreditation also addresses the cost recovery issues raised during the forum's second panel.[39] If accreditation were to consider fuel security, a generator

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[37] Tr. at 17 (M. Asthana), 23 (J. Robb), 21, 38-39 & 67 (J. Bowring); 123 (A. Keech).
[38] *Id.* at 25.
[39] Tr. at 71 (M. Phillips reporting result from consultant study for New England that firm gas adds $6/kW-month to generator costs, which we calculate is equivalent to $20/MW-day).

would be able to increase its capacity value by obtaining firm fuel. When the cost of firm supply is included in the offer price of that segment of capacity, the market can determine if firm fuel is a cost-effective resource adequacy measure, and the supplier can be assured they are appropriately compensated for their fuel supply arrangement.

PJM needs a robust system of accreditation and penalties to incent gas generators to obtain firm and flexible fuel supply arrangements. If these gas plants, with all these costs reflected, are still needed by the market, then the market will send appropriate signals for the development of any infrastructure necessary to support them. The need for additional pipelines should not be assumed, as several panelists suggested, but rather must be demonstrated by market demand for firm service and transportation, as incented through PJM's market rules.

c. Electricity Markets Should Not Create Opportunities for Market Manipulation by Gas Suppliers.

Generators must be able to recover the costs they incur to deliver cleared offers in any market, including fuel costs. However, guaranteed cost recovery creates an opportunity for market manipulation. To prevent manipulation, the Commission has created a rigorous system of market monitoring for the electricity sector that aims to prevent anti-competitive outcomes. A key aspect of this system is reviewing the legitimacy of claimed costs.

Panelists raised issues regarding gas supply cost recovery. PIOs are concerned that unmitigated fuel cost recovery by gas units—through either capacity or energy market offers—may enable behavior by gas suppliers that has the same effect on electric ratepayers as market manipulation by generation owners. The Commission should not allow anticompetitive behavior simply because it has moved upstream.

First, several panelists identified the need to allow suppliers to include the cost of firm gas supply in their capacity offers.[40] This is a legitimate need (assuming these costs are not recoverable through energy market offers), and as described above, in a competitive market is best addressed through accreditation and market clearing. However, RPM is not a competitive market.[41] The Market Monitor routinely finds that all suppliers in RPM auctions have market power and are subject to mitigation.[42] Under these conditions, allowing unmitigated pass-through of gas supply contract prices may give gas suppliers (who are not subject to PJM's mitigation rules) market power. A gas supplier that determines a power plant it supplies is pivotal in RPM would have the opportunity to raise supply contract prices to a level limited only by RPM clearing caps. Generation owners would be indifferent to any costs fully recoverable through capacity payments if they were also confident they would clear.

Second, panelists noted costs associated with inflexible gas scheduling. Gas customers often have to purchase 24 hours of gas service to ensure supply during peak hours. The situation worsens on weekends and holidays, when several days' nominations must be made at once.[43] Currently, those costs cannot be passed on to ratepayers,[44] forcing generator owners to evaluate those costs on their economic merits and thus disciplining gas providers' asking prices. If generators are guaranteed recovery of costs associated with gas scheduling, this discipline weakens. When a generator is determined to have energy market power, it is mitigated to cost-based offers. To the extent that a generator's gas supplier has control over items included in

[40] Tr. at 25:19 (J. Robb); 71 (M. Phillips). The Market Monitor disagrees with the claim that firm gas is not recoverable. Tr. at 39.
[41] *See, e.g.*, Monitoring Analytics, *2022 State of The Market Report for PJM*, at 299 (Mar. 2023) ("The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change…Market power is and will remain endemic to the structure of the PJM Capacity Market.").
[42] *Id.* at 300.
[43] Tr. at 127-28 (M. Phillips).
[44] *Id.*

cost-based offers, the generator's market power is simply transferred to the gas supplier. Any cost recovery scheme must ensure that this does not become a loophole to evade market monitoring. Similar concerns apply in times when the energy market is in shortage, or when generators face capacity penalties.

Ideally, FERC will holistically address the reliability and market power issues arising from gas-electric coordination. Until then, accurately incorporating the reliability consequences through accreditation and limiting generator fuel-supply cost recovery to costs prudently incurred by the supplier are partial solutions that can be implemented through electricity tariffs.

4. Improving Accreditation is the Most Important Next Step for RPM.

As PJM's Vice President of Market Design and Economics asserted, "accreditation is incredibly important."[45] We agree. Accreditation is the process of quantifying resources' contribution to resource adequacy. Shortcomings in PJM's current accreditation process are behind both the immediate reliability dangers of poor winter performance and may contribute to inaccurate price signals. Correct accreditation will ensure least-cost resource adequacy through the energy transition.

a. Estimated Load Carrying Capacity ("ELCC")

ELCC has emerged as the industry standard for resource adequacy accreditation.[46] While the calculations are complex, the concept behind ELCC is simple: starting with a model system that meets reliability standards, add a unit of some type of resource. This will raise reliability. Then, increase the load in the model until reliability falls back to the standard. The amount of load the new resource enables while holding reliability constant determines its ELCC.

[45] Tr. 83:23 (A. Keech).
[46] Tr. 117 (J. Wilson); *see also id.* at 83-34 (A. Keech); 77 (A. Hopper).

The modeling used to estimate the reliability of a system is what gives ELCC its distinctive advantages. This modeling is generally done at hourly or finer resolution over a large number of load and generator profiles which are derived from historical data. This approach allows ELCC to capture features that are missed in legacy statistical approaches, including correlations between generator performance and load, between generators and each other, dispatch limits, and detailed characteristics of supply performance.

The output of an ELCC model is generally expressed as a percentage of nameplate, and can be interpreted to mean the amount of "perfect capacity" that resource can replace without affecting reliability. This is a measure of a resources' contribution to meeting reliability targets, and not a statement of the resources' real-time operational capacity.[47] Take, for example, hypothetical nuclear and solar plants, both with an ELCC of 97 MW. For the nuclear plant, this might reflect that it can be expected to be available to deliver 100 MW of energy 97% of the time. For the solar plant, it reflects that the plant might be able to deliver 250 MW on summer days, 20 MW on winter afternoons, and nothing at night. The ELCC value incorporates the system risk during each of those periods, and reflects the finding that the two plants' output profiles bring equivalent reliability benefits. It should not be misunderstood as an assumption that the solar plant produces energy at night, or is compensated as though it does.

Critically, this approach allows ELCC to incorporate many supply attributes into a single metric.[48] Because the underlying models incorporate dispatch and performance at an hourly level, generator operating parameters, storage energy limits, renewable intermittency, and correlated outages of fossil plants can all contribute to a resource's ELCC.

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[47] *See id.* at 134 (C. Roberts).
[48] *See* Tr. at 104 (A. Keech).

b. ELCC addresses today's resource adequacy concerns.

As discussed in more detail in Section 3.a, incorrect accreditation of gas-fired power plants is a direct cause of winter reliability problems and artificially inflates supply. Moving those resources to an ELCC-based accreditation can solve both of these issues. As the Commission considers ELCC accreditation for thermal resources, it should ensure that the approach considers both fuel supply arrangements and resource operating parameters. Fuel supply is important both for the obvious reason that resources with firm fuel offer more reliability benefits, and to send an actionable price signal to fossil plant owners on the value of firm fuel and allow firm fuel gas to be compared on an economic basis with other capacity resources.

Resource operating parameters, including those created by gas scheduling constraints, should also be included in accreditation. Regardless of the cause, resources that must be scheduled well in advance have less reliability value, simply because emergency situations may evolve before those units can respond. Meaningful quantities of capacity were unavailable due to lead times during Elliott in PJM and ISO-NE, contributing to emergency conditions in both ISOs.[49]

c. ELCC supports reliability through the energy transition.

ELCC values are a function not only of a resource and load, but of the characteristics of the base system it is being modeled against. A resource that produces power primarily during low-risk hours will have a low ELCC. This prevents results such as those raised by Commissioner Danly where a capacity market clears 100% solar resources.[50] As the amount of

[49] *See Opening Statement of Casey Roberts*, *supra*, at 2-4; *see also id.,* Attachment A, Synapse Energy Economics, *The Impact of Resource Inflexibility on Capacity Accreditation in New England* (March 2023).
[50] Tr. at 80.

solar increases, reliability risk during daylight hours decreases, reducing solar's ELCC. When the system reaches the point where all reliability risk is at night, additional solar will bring no additional value, and thus stop displacing other resources.[51]

More generally, because ELCC is based on detailed modeling of the electrical system as a whole, it captures many of the characteristics needed for resource adequacy and reflects them in accreditation. This is a major step forward from legacy approaches such as PJM's current system for thermal generators, which are based on statistical summaries of individual generators considered in isolation. Resources that do not provide needed attributes will see their capacity values decline or even vanish.[52] This ensures that the capacity market will clear a resource mix that supports reliability, and, via accreditation values, send economic signals regarding what resources are most needed for reliability.

This holds true in the face of policies that benefit particular technologies—a concern raised by Commissioner Danly during the forum.[53] While these technologies will displace others with fewer policy-driven revenues, accurate accreditation ensures that this will only happen to the extent consistent with reliability. A resource with a capacity value of zero will not displace anything no matter how much revenue it receives pursuant to state and federal policy. Provided accreditation is correct, ordinary market forces will support less-subsidized resources to the level necessary to meet the reduced need for their capacity. This is the point supporters of the old MOPR miss: policy-supported resources reduce the need for other resources. To the extent these resources' offers reduce the market price, this is the mechanism that shrinks the less-subsidized

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[51] The exact mechanism for this varies depending on ELCC implementation. Under "marginal" approaches, the ELCC value of solar becomes zero in this situation. Under "average" approaches, the ELCC value of the solar fleet stops growing, and as more solar is added is spread more thinly over all solar resources.
[52] Tr. at 135-36 (J. Wilson); 77-78 (A. Hopper).
[53] *See* Tr. at 40-41 & 80-81.

fleet. Once that fleet is appropriately sized, prices will return to previous levels. The MOPR was always about preventing the quantity of less-subsidized resources from correctly adjusting in response to state energy policies.

d. ELCC implementation will require some changes to capacity market structures.

We are in a transition period from legacy accreditation methods to ELCC; as of now, only NYISO has an approved tariff using ELCC for all resources, and that has yet to be fully implemented. As this change progresses, contradictions will emerge between market rules based on the current paradigm, where a MW of capacity reflects a commitment to provide a MW of energy, and the ELCC paradigm, where a MW of capacity reflects the contribution (or marginal contribution) to resource adequacy. While those issues will be addressed in specific in future dockets, we raise two general concerns here.

- Benefits of ELCC resources must be allocated fairly. In some implementations of ELCC, a portion of reliability value is not reflected in accreditation, but instead is accounted for by reducing capacity requirements.[54] To date, NYISO is the only region that has implemented this "marginal" approach, but it appears likely to be adopted by PJM and other RTOs. In a multi-state RTO, the market must consider which wholesale customer's capacity requirements should be reduced to equitably assign the benefits of ELCC resources. A simple blanket reduction in required reserve margins across the region would appear to result in some benefits of state-supported resources being allocated to states that did not pay for them.

[54] *New York Independent System Operator*, 179 FERC ¶ 61,102 at P 77 (May 10, 2022) (explaining that NYISO's method of reducing the procurement target to reflect its marginal accreditation approach avoided undercounting the reliability value of capacity resources).

- Obligations and penalty structures must align with accreditation. In several RTOs, including PJM, obligations and penalties are based on the definition of capacity as a guarantee to deliver energy. Applying this to ELCC resources creates several inconsistencies. First, it does not support reliability, as the system operator will often count on an ELCC-accredited resource to deliver more energy than its ELCC rating, sometimes much more.[55] Obligating resources to perform at their accreditation does not reflect this, and can result in the unacceptable situation where all resources meet their commitments but the system still is unable to serve load. In such a case, the capacity performance structure may need revisions to serve its intended purpose. Conversely, ELCC resources' limits are already reflected in their ELCC values, and so requiring them to deliver during periods they were not expected to perform is equivalent to penalizing them for not providing services they aren't being paid for. The most obvious example of this is PJM penalizing solar for not being available at night.[56] Market rules must be corrected so that ELCC resources' obligations match the assumptions used in their accreditation.

5. Ongoing PJM Stakeholder Discussions Regarding Capacity Market Reform

PJM is currently engaged in a stakeholder process through its Critical Issue Fast Path – Resource Adequacy ("CIFP"), which will result in a proposal for significant reforms to the capacity market with a targeted filing date of October 1, 2023. Various forum participants suggested that the Commission should not mandate reforms to the capacity market until the

[55] For example, based on 2025/26 ELCC values, a fixed panel solar resource is expected to deliver 270% of its ELCC during peak output hours and a 4-hour storage system is expected to deliver 130% of its ELCC during those four hours.
[56] This unreasonable penalty structure is at issue in a complaint pending before the Commission. *SunEnergy1, LLC v. PJM Interconnection, LLC*, Docket No. EL23-58.

Commission has an opportunity to review the reforms that PJM itself will suggest. PIOs have been active participants in the CIFP process and believe that it will likely result in some necessary improvements to the capacity market. However, further improvements will likely remain necessary even after the CIFP process concludes. This sort of iterative work on the capacity market's structure is appropriate as PJM adapts to the energy transition.

During the CIFP process, PJM has properly focused on risks to reliability throughout the year, rather than basing the market's annual structure solely on summer peak loads. PJM has presented results from its own modeling showing that a large portion of the risks to reliability actually occur in the winter, due in significant part to correlated outages at thermal plants.[57] We appreciate PJM's recognition of the significant role that fossil fuel plants' correlated outages play in driving reliability risks. However, we also believe that PJM must be careful not to over-correct by exaggerating winter risks or by taking an approach to reliability that is more conservative than the risks actually merit. An accurate assessment of winter risks will require a well-vetted and data-driven approach to weather trends, evolving generator performance, and other risk factors. One way in which PJM appears to be taking an overly conservative approach is by ignoring the likelihood of imports from other regions when calculating its installed reserve margin. PJM has not provided any analysis that such imports are unlikely to be available from diverse neighboring regions (an analysis it has done for years as part of its Reserve Requirement Study), but instead has stated simply that it thinks it should not rely upon the possibility of imports. Such an unsubstantiated approach overstates reliability risks and will cause consumers to buy unnecessary capacity at unreasonably high prices.

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[57] *See generally* PJM, *Update on Reliability Risk Modeling*, Presentation to CIFP – Resource Adequacy (Jul. 17, 2023), available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230717/20230717-item-03---reliability-risk-modeling---july-update-v2-copy.ashx.

As a result of its modeling demonstrating heightened winter risk, PJM began developing a proposal for a seasonal capacity market. We strongly support PJM moving to a seasonal market, which—if designed correctly—can allow more accurate procurement levels in each season, promote more fruitful market participation from resources with seasonal characteristics, and ensure that consumers are purchasing the lowest-cost mix of resources to guarantee reliability throughout all times of the year. A seasonal market also sharpens the price signal for firm gas supply, both identifying if and where pipeline investment might be needed and encouraging full utilization of gas infrastructure in the summer. However, in part because PJM began work on a seasonal market late in the CIFP process, the design of this market is not complete. Because PJM's seasonal market design continues to evolve, we remain uncertain whether PJM's final proposal will include the granularity or other essential design components that maximize the value of a seasonal market—or even whether PJM will propose a move to a seasonal market at all. It is critical to get this design right, which will require ample opportunities for stakeholder input and feedback. However, PJM must move quickly to solicit such input and propose a seasonal design in order to avoid the unreasonable result of requiring consumers to procure capacity to meet a summer peak based on capacity accreditation factors strongly influenced by performance issues that are unique to winter. Regardless of whether PJM proposes a seasonal or annual market as part of its CIFP package, the Commission should strongly urge PJM to continue to work with stakeholders on the design of a robust and accurate seasonal market.

PJM has made significant progress toward improving its accreditation to more accurately reflect correlated outages. PJM intends to propose applying an ELCC accreditation to all capacity resources, which should more accurately account for correlated outages and help to put all capacity resources on an even playing field. Combined with a seasonal market, this approach may also facilitate more full participation in the capacity market by resources with different generation profiles in different seasons. However, based on recent presentations during the stakeholder process, we are concerned that PJM does not intend to incorporate fuel-supply arrangements into the accreditation of gas plants. Fuel-supply arrangements significantly affect whether gas plants can perform when needed. During Winter Storm Elliott, gas plants with non-firm fuel supply performed much more poorly than plants with firm supply or dual-fuel capability.[58] Incorporating fuel supply into accreditation is also the best option to price the electric reliability value of gas delivery infrastructure. We encourage PJM to continue to consider this issue, to incorporate fuel-supply arrangements into accreditation, and to do so in the near future if it finds it lacks information necessary to do so as part of the CIFP. We will also continue to monitor whether an approach taking unit-specific performance into account can adequately address this issue; thus far PJM has offered little transparency regarding the impact of unit-specific adjustments, which will be critical for the market's ability to differentiate between gas plants based on their fuel supply arrangements.

PJM also appears likely to retain a capacity performance system that involves significant penalties for capacity resources that fail to perform when called and bonus payments for capacity resources that exceed their expected performance during times of system stress. PJM staff have proposed changes to the triggers for Performance Assessment Intervals ("PAIs"), similar to those recently approved by the Commission for the next two delivery years, which will likely mean that fewer PAIs occur and that overall levels of penalties and bonuses will be smaller than those

[58] PJM, *Winter Storm Elliott: Event Analysis and Recommendation Report*, at 59 (depicting that on each day of Winter Storm Elliott, non-firm gas plants had far higher outage rates than plants with firm fuel supply or dual-fuel capability).

accrued during Winter Storm Elliott. PJM will also likely propose that only capacity resources that cleared the auction in the delivery year would be eligible for bonuses, which would alter the present system in which any capacity resource that overperforms during times of system stress is eligible for bonuses. Finally, PJM will likely retain a must-offer exemption to its participation requirements, under which intermittent and storage resources do not have an obligation to offer into the capacity market. Many other aspects of PJM's capacity performance structure will remain unaltered, including the potential for penalties to accrue to intermittent resources that do not perform when it is physically impossible for them to do so.

Generally, we support PJM's retention of a robust capacity performance system. However, PJM's retention of a must-offer exemption for intermittent and storage resources is effectively an acknowledgement that capacity market obligations and penalties are not reasonable for all resource types.[59] PJM has explained that "removing the must offer exemption while continuing to subject units of these resource types to PAI penalties during time periods in which they have no ability to physically hedge the risk (e.g. solar at night) imposes inefficient risks for them."[60] While we agree that penalizing solar resources for not generating electricity at night is unreasonable and provides no incentive to improve reliability,[61] the must-offer exemption is not the optimal solution to this problem, as it results in less available capacity being offered.[62] Especially because solar resources, and more generally renewable and storage

[59] *See* Section 4.c, *supra.*
[60] PJM, Capacity Market Reform: PJM Proposal, July 27, 202 at 26, available at https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230727/20230727-item-02a---cifp---pjm-proposal-update---july-27.ashx.
[61] *See* Combined Protest and Answer of Sierra Club to Complaints Regarding Nonperformance Penalties During Winter Storm Elliott at 12-25, Docket No. EL23-53 et al. (May 26, 2023), Accession No. 20230526-5252.
[62] *Id.* at 21-25; *see also ISO New England Inc. New England Power Pool Participants Committee*, 179 FERC ¶ 61,139, at P 50 (2022) (noting that deterring resources from participating in the capacity market "effectively ignore[s]" their "contribution to resource adequacy," which in turn causes the capacity market "to clear surplus resources that are not actually needed to maintain reliability"); *New York Independent System Operator*, 179 FERC ¶ 61,102, at P 39 (2022) (noting that deterring resources from participating in the capacity market can cause "at least

resources, constitute the vast majority of the resources in PJM's interconnection queue, it is imperative that PJM design a capacity performance structure that allows for these resources to fully participate without being exposed to unreasonable penalties. We do not believe the CIFP process will resolve this issue, and we strongly encourage PJM to take this issue up as soon as possible after the CIFP concludes.

Finally, we have concerns that consumers and other stakeholders lack adequate information about likely price impacts from PJM's capacity reforms. Whereas NYISO and ISO-NE perform consumer-impact analyses when considering significant market reforms,[63] PJM has been reluctant to provide similar information, purportedly due to concerns about potentially disclosing competitively sensitive information. As a result, although it appears likely that PJM's CIFP reforms will increase prices in the capacity market, the scale of this change remains unclear. While we recognize that the Commission's ultimate approval or disapproval of PJM's CIFP reforms will not require a detailed cost-benefit analysis, we believe that all stakeholders—and consumer advocates in particular—would be able to participate in a more full and informed manner if they have information about reforms' likely impacts on prices. We recognize that PJM has responded to stakeholder calls for such information by indicating that it will perform a limited analysis of how its potential reforms would have altered the clearing price from a prior auction. However, there is no guarantee that this information will be available to stakeholders before they have to vote on PJM's proposed reforms. We believe that it would be very helpful

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three significant harms: over-procurement of capacity, inflated capacity market prices, and inefficient price signals from the capacity market").

[63] *See, e.g.*, NYISO, Capacity Accreditation: Consumer Impact Analysis, Oct. 19, 2022, https://www.nyiso.com/documents/20142/33857891/03_Consumer%20Impact%20-%20Capacity%20Accreditation.pdf/1e9097c6-c0ae-b137-dd44-15ce1f5a7841 (evaluating cost impacts of changes to capacity accreditation rules); Todd Schatzki et al., Analysis Group, *Energy Security Improvements Impact Assessment*, Apr. 2020, https://www.iso-ne.com/static-assets/documents/2020/04/esi-impact-assessment-final-15-apr-2020.pdf (on behalf of ISO-NE, evaluating consumer cost impacts of ISO-NE Energy Security Improvements proposal).

for future stakeholder proceedings for the Commission to provide guidance on what level of analysis PJM should conduct on price impacts and when that analysis should be available to stakeholders.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing has been served in accordance with 18 C.F.R. § 385.2010 upon each party designated in the official service list compiled by the Secretary in this proceeding, by email.

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Dated: August 14, 2023