July 30, 2024

Administrator Michael Regan
Office of the Administrator
U.S. Environmental Protection Agency
Room 3000, WJC West Building
1200 Pennsylvania Avenue NW
Washington, DC 20460

Re: Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration

Dear Administrator Regan:

Mountain State Energy Holdings, LLC (MSEH) submits this Petition for Rulemaking and Reconsideration on behalf of its subsidiary Mountain State Clean Energy, LLC (MSCE). MSEH owns two assets: a highly efficient 710 megawatt coal-fired unit owned by MSEH's subsidiary, Longview Power LLC (Longview Power), and a fully permitted and planned combined cycle gas turbine unit owned by MSCE, which would be the most efficient unit of its kind in the nation.

The EPA's recent rulemaking has managed to effectively terminate both of these assets. New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024) (Final Carbon Rule).

The Administrative Procedure Act provides interested persons the right to petition an agency for the issuance, amendment, or repeal of a rule. 5 U.S.C. § 553(e). Alternatively, Section 307 of the Clean Air Act permits an aggrieved party to petition EPA to consider new information that arises after promulgation of a final rule. 42 U.S.C. § 7607(b)(1).

New information has arisen that warrants reconsideration of the Final Carbon Rule and calls for EPA to repeal or amend the rule. First, under EPA's own assumptions for future energy resources and energy demand, there is a significant likelihood of major power outages in the PJM Interconnection region. Second, regional power authorities have begun to develop FERC-approved accreditation protocols that are significantly more conservative than EPA's estimates for the performance of not just intermittent energy resources but also dispatchable resources, casting serious doubt on EPA's resource adequacy analysis. Third, a new baseline reality for electricity demand is solidifying, with all regional power authorities revising long-term electricity demand forecasts significantly upward. The likelihood of major power outages increases dramatically under a higher energy demand scenario. Fourth, EPA made significant changes to the Final Carbon Rule from the proposed version that have made financing impossible.

The enclosed Petition is styled as a Petition for Rulemaking and Reconsideration. In light of the new information and analysis discussed below MSEH respectfully petitions for rulemaking to amend the Final Carbon Rule, or, in the alternative, reconsideration of the Final Carbon Rule under the Clean Air Act. New information regarding increased electric demand arising since the close of the comment period, coupled with flaws in EPA's modeling approach exacerbated by that increased demand, make reconsideration appropriate and necessary in these circumstances.

MSEH looks forward to EPA's decision with respect to the enclosed Petition.

Respectfully submitted,

By: /Stephen Nelson/
Stephen Nelson
CEO
Mountain State Energy Holdings LLC

Enclosure

CC: Gautam Srinivasan, Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel
Lisa Thompson, Sector Policies and Programs Division, Office of Air Quality Planning and Standards

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

PETITION FOR RULEMAKING AND RECONSIDERATION

INTRODUCTION

Mountain State Energy Holdings, LLC (MSEH) submits this Petition for Rulemaking and Reconsideration on behalf of its subsidiary Mountain State Clean Energy, LLC (MSCE). MSEH owns two assets: a highly efficient 710 megawatt coal-fired unit owned by MSEH's subsidiary, Longview Power LLC (Longview Power), and a fully permitted and planned combined cycle gas turbine unit owned by MSCE, which would be the most efficient unit of its kind in the nation. With its recent Final Carbon Rule,[1] EPA has managed to effectively terminate both of these assets.

The Administrative Procedure Act provides interested persons the right to petition an agency for the issuance, amendment, or repeal of a rule.[2] Alternatively, Section 307 of the Clean Air Act permits an aggrieved party to petition EPA to consider new information that arises after promulgation of a final rule.[3]

New information has arisen that warrants reconsideration of the Final Carbon Rule and calls for EPA to repeal or amend the rule. First, under EPA's own assumptions for future energy resources and energy demand, there is a significant likelihood of major power outages in the PJM Interconnection region. Second, regional power authorities have begun to develop FERC-approved accreditation protocols that are significantly more conservative than EPA's estimates for the performance of not just intermittent energy resources but also dispatchable resources, casting serious doubt on EPA's resource adequacy analysis. Third, a new baseline reality for electricity demand is solidifying, with all regional power authorities revising long-term electricity demand forecasts significantly upward. The likelihood of major power outages increases dramatically under a higher energy demand scenario. Fourth, EPA made significant changes to the Final Carbon Rule from the proposed version that have made financing impossible.

This new information leads to a single conclusion: The Final Carbon Rule will dramatically undermine grid reliability, and it must be reconsidered and amended to allow new dispatchable energy resources to be developed that will stabilize grid reliability.

Accordingly, this Petition is styled as a Petition for Rulemaking and Reconsideration. In light of the new information and analysis discussed below MSEH respectfully petitions for rulemaking to amend the Final Carbon Rule, or, in the alternative, reconsideration of the Final Carbon Rule under the Clean Air Act. New information regarding increased electric demand

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[1] New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024) (Final Carbon Rule).

[2] 5 U.S.C. § 553(e).

[3] 42 U.S.C. § 7607(b)(1).

arising since the close of the comment period, coupled with flaws in EPA's modeling approach exacerbated by that increased demand, make reconsideration appropriate and necessary in these circumstances.

EXECUTIVE SUMMARY

MSEH has built its business on the generation of reliable, dispatchable, efficient, and clean fossil fuel-powered electricity. With a heat rate of only 8700 Btus/KWh, Longview Power's coal-fired unit in Maidsville, West Virginia is one of the most efficient coal-fired units in the world. Longview Power is a global leader in terms of control of conventional environmental pollution and heat efficiency.

Building on this legacy, MSEH and MSCE have been for several years developing one of the most efficient natural gas combined cycle (NGCC) units in the world. This unit is fully permitted to utilize both natural gas and hydrogen, which positions it perfectly to provide reliable, resilient, and low-carbon power to a grid needing more dispatchable power to meet the growing needs of the PJM region. Yet, despite being on the bleeding edge of gas- and hydrogen-powered baseload generation technology, no financing is available. Financiers refuse to take the risk that EPA's mandates in the Final Carbon Rule are technically and economically feasible within the time limits specified within the Rule. As a merchant plant, costs of the project cannot be passed on to ratepayers, so the viability of the project lies in the hands of financiers and their assessment of the Final Rule's feasibility.

Although not the subject of this Petition, EPA's Final Carbon Rule also threatens MSEH's other essential asset given that EPA's unrealistic mandates for existing coal-fired units will force Longview Power's state-of-the-art, highly efficient coal-fired unit to cease operating as such and perhaps cease operating entirely. No coal-fired power plant can implement CCS with 90% capture in the next 7 years, even Longview Power's unit.

This is a challenge for MSCE and MSEH, but more importantly, this is a problem for the grid. Since EPA has finalized the Final Carbon Rule, several new developments have emerged that warrant the Agency's reconsideration of the Final Carbon Rule. First, a deeper examination of the Agency's resource adequacy study demonstrates significant issues with its methodology and assumptions—EPA's own analysis shows that significant power outages are likely. Second, electricity demand continues to surge nationwide, casting serious doubt on EPA's resource adequacy assurances in the Final Carbon Rule. The grid is facing a fundamental reliability crisis, and new dispatchable energy resources are needed to fill the gap. EPA must reconsider the Final Carbon Rule and re-propose these standards to allow generation resources that have already been planned and permitted to be constructed.

Under Section 307(d)(7)(B) of the Clean Air Act (CAA) and Sections 553 and 705 of the Administrative Procedure Act (APA), MSCE petitions the Administrator of the United States Environmental Protection Agency to reconsider and rescind the natural gas combustion turbine portion of the Final Carbon Rule. EPA should grant reconsideration and re-propose standards for natural gas combustion turbines that have been permitted but not yet constructed in order to support grid reliability.

BACKGROUND

MSCE has been developing for many years a 1,100+ megawatt combined cycle gas turbine facility. This facility is fully permitted and would be constructed adjacent to Longview Power's coal facility in Maidsville, West Virginia.

MSCE first submitted its air quality permit application on July 3, 2019. The West Virginia Public Service Commission granted MSCE's siting certificate on April 3, 2020. The facility's construction permit was granted by the West Virginia Department of Environmental Protection's (WVDEP) Department of Air Quality on January 5, 2022. At the end of 2023, MSCE submitted an air permit modification to allow the facility to utilize up to 30% hydrogen; approval for this modification is expected in August 2024.

MSCE's combined cycle gas turbine project is designed to fire both natural gas and hydrogen, and if constructed, would provide between 1,100 megawatts (hydrogen) or 1,270 megawatts (natural gas) of power to the PJM Interconnection market. MSCE's project is uniquely positioned to provide reliable, resilient and affordable power to meet demand growth in PJM while having the flexibility to comply with a rapidly changing environmental compliance and electricity demand landscape.

The project is capable of meeting a significant need. It could provide power generation to major metropolitan areas such as Baltimore, Washington, D.C., New Jersey, and Philadelphia. As planned, the turbines would be capable of co-firing hydrogen with natural gas from 30% to 50% blend with plans to be fully hydrogen capable at some point in the future. With hydrogen as its primary fuel, MSCE's project would be one of the first, if not the first, large scale hydrogen-fired dispatchable power plants with a significant output of carbon-free power. With an expected capacity factor of greater than 90%, MSCE's project could produce a significant amount of low-carbon power while still utilizing Appalachia's natural gas supply by capturing and sequestering most of the carbon dioxide produced through the hydrogen production process. An expected baseload nominal heat rate of ~6,100 Btu/kWh (NG fired) would place the project as one of the most efficient CCGTs in PJM burning low-cost gas.

But this incredible facility may never be constructed.

The viability of MSCE's CCGT project is threatened by EPA's treatment of new combustion turbines in EPA's New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024) (Final Carbon Rule).

For new gas-fired power plants, the Final Carbon Rule subcategorized units based on annual capacity factor, creating three subcategories:

- Low-load units, with an annual capacity factor of less than 20%;
- Intermediate load units, with an annual capacity factor between 20% and 40%; and
- Base load units, with an annual factor of 40% or greater.

For base load units, such as MSCE's 1,100+ megawatt combined cycle gas turbine facility, EPA determined that the Best System of Emissions Reduction (BSER) under § 111(b) of the Clean Air Act was a standard based on carbon capture and storage with a 90% CO_2 capture rate.[4] New units that commence construction after May 23, 2023, would be required to meet this standard by January 1, 2032.[5]

As MCEH argued in its comments submitted as a part of the regulatory docket for the Final Carbon Rule, CCS with 90% capture is not adequately demonstrated for either existing coal-fired units or new gas-fired combined cycle units.[6] But even if it were, new projects that must comply with EPA's regulatory deadline are not financeable. MSEH knows this because it has been working to obtain financing for its project for the last year: no bank or investor believes CCS with 90% capture is possible on EPA's timeline.[7] As an independent power producer (IPP), MSEH cannot build what it cannot finance. Unlike vertically integrated utilities, IPPs cannot simply pass the risk on to captive ratepayers.

Although EPA proposed an annual capacity factor threshold of 50% for baseload units, this threshold was lowered to 40% in the Final Carbon Rule. As an IPP, MSEH cannot recover the cost of its investment in this state-of-the-art, highly efficient unit while operating less than 40% of the year.

Further, although EPA proposed emissions guidelines for existing gas- and oil-fired combustion turbines, EPA did not move forward with finalizing these guidelines in the Final Carbon Rule.[8] This shift fundamentally changed the economics from the proposed to final rule because new gas-fired units must compete with existing, uncontrolled gas- and oil-fired capacity. Until the standards for these existing units is known, significant regulatory uncertainty overhangs the electricity markets and financing for new projects.

[4] 40 C.F.R. § 60.5520a (referring to Table 1 to subpart TTTTa).

[5] *Id.* § 60.5509a.

[6] Mountain State Energy Holdings, LLC, Comment Letter on EPA Proposed Carbon Rule (Aug. 8, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0829.

[7] Indeed, in its Regulatory Impact Analysis, EPA appears to assume that very few natural gas combined cycle power plants with CCS will be constructed (1 GW total capacity). Regulatory Impact Analysis for the Final Carbon Rule, 3-31 to 3-32, *docketed as* EPA-HQ-OAR-2023-0072-8913.

[8] Final Carbon Rule, 89 Fed. Reg. at 39,798.

ISSUES MERITING RECONSIDERATION AND RULEMAKING

I. Through its Final Carbon Rule, EPA Endangers the Electric Grid.

In promulgating the Final Carbon Rule, EPA argued that the Rule would not cause grid reliability impacts:

> The EPA does not believe that determining CCS to be [the Best System of Emissions Reduction] BSER for base load combustion turbines will cause reliability concerns, for several independent reasons. First, the EPA is finalizing a determination that the costs of CCS are reasonable and comparable to other control requirements the EPA has required the electric power industry to adopt without significant effects on reliability. Second, base load combined cycle turbines are only one of many options that companies have to build new generation. The EPA expects there to be considerable interest in building intermediate load and low load combustion turbines to meet demand for dispatchable generation. . . . In 2023, combined cycle turbines are only expected to represent 14 percent of all new generating capacity built in the U.S. and only a portion of that is natural gas combined cycle capacity. . . . Several companies have recently announced plans to move away from new combined cycle turbine projects in favor of more non-base load combustion turbines, renewables, and battery storage.[9]

However, information available to the Agency during the rulemaking process combined with new information that has arisen after promulgation of the Final Carbon Rule clearly establishes that the Final Carbon Rule endangers grid reliability.

A. <u>EPA Failed to Conduct a Grid Reliability Study When Considering the Final Carbon Rule and Has Yet to Conduct or Release One.</u>

EPA provided assurances that the Final Carbon Rule would not jeopardize the electric grid, but the Agency's assurances lack basis at least with respect to PJM.[10] Indeed, the Agency conducted only an annualized resource adequacy study, rather than an hourly or even daily grid reliability study before issuing the Final Carbon Rule.[11] This annualized resource adequacy analysis cannot answer the question of whether electricity supplies will meet demand every hour of the day due to seasonal and hourly fluctuations in both supply and demand. Indeed, EPA concedes this point in its Resource Adequacy Analysis Technical Memo, where the Agency notes that "[r]resource adequacy is an important *aspect of* grid reliability."[12]

Although several commenters provided grid reliability studies that demonstrated that the proposed version of the Final Carbon Rule would create significant grid issues, EPA did not

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[9] *Id.* at 39,937.

[10] *Id.* at 39,803.

[11] *Id.*

[12] Resource Adequacy Analysis: Technical Support Document, 2 (Apr. 2024), *docketed as* EPA-HQ-OAR-2023-0072-8916 (emphasis added).

meaningfully respond to these comments in the preamble to the final rule or the response to comments document issued as a part of the rule.

Using the Integrated Planning Model, EPA modeled and predicted the power resources that will be available for each of its model years. The Agency then compared these energy resource predictions to expected electricity demand for each year. This kind of analysis is merely a starting point and does not account for seasonal fluctuations, extreme weather events, or real-world performance of dispatchable resources.

To that point, EPA's annual capacity values for renewable energy resources are unreasonably disconnected from how regional power authorities, with approval from the Federal Energy Regulatory Commission (FERC) forecast and manage grid reliability. EPA uses *annual* capacity values for renewable energy resources, while regional power authorities and FERC are moving to *seasonal* accreditations for grid planning purposes. This trend flows from the commonsense recognition that seasonal weather plays a significant role in the performance of wind and solar energy resources.

Further, regional power authorities across the board are revising accreditations downward as renewables play a bigger part of the overall energy mix and as dispatchable energy resources retire.[13] EPA's assumptions for intermittent resource capacity values bear little resemblance to the assumptions used by regional power authorities.[14]

The problems with EPA's assumptions are not solely related to renewable energy resources. The Agency also uses unrealistic capacity values for dispatchable resources, assuming they will be available 100% of the time. All energy resources must undergo routine maintenance and scheduled downtime and some will be forced offline during periods of peak demand. Yet EPA assumes they will be fully available when needed during extreme weather events. As grid

[13] For instance, the Southwest Power Pool is in the process of moving to a new set of accreditation rules. These new rules use an effective load carrying capability (ELCC) methodology for wind, solar, and battery resources. To maintain grid reliability, this means that these resources would receive an accreditation value that considers its loss of load expectation during extreme weather events. Practically, this means that these resources receive a lower accreditation value as that resource becomes a greater share of the energy mix within SPP. *See* Southwest Power Pool, Submission of Tariff Revisions to Implement Effective Load Carrying Capability Methodology and Performance Based Accreditation, FERC Docket No. ER24-1317-000 (Feb. 23, 2024), *available at* https://www.spp.org/spp-documents-filings/?id=438816. The Midcontinent Independent System Operator (MISO) is undergoing a similar reform of its accreditation framework to address reliability issues. Midcontinent Independent System Operator, Inc.'s Filing to Reform MISO's Resource Accreditation Requirements, FERC Docket No. ER24-1638-000 (Mar. 28, 2024), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240328-5329&optimized=false.

[14] As an example, EPA's resource adequacy modeling relies on an 82% annual capacity factor for existing solar resources within the SPP region for each model year run by the Integrated Planning Model. *See* EPA, Analysis of the Final Greenhouse Gas Standards and Guidelines: Power Sector Modeling, Final Rule Output Files, https://www.epa.gov/power-sector-modeling/analysis-final-greenhouse-gas-standards-and-guidelines. Capacity values are calculated by summarizing the Reserve Margin Capacity by capacity type for the applicable regions and dividing by the respective Dispatch Capacity from the GHG Final Rule RPT file named "Final Rules SupplyResourceUtilization.xlsx" contained within the Final Rule IPN run zip file.

This stands in stark contrast to SPP's pending accreditation values for solar capacity, which begin at 72% in the summer and only 19% in the winter. As solar becomes a larger share of the overall grid within SPP, these capacity values decrease to 40% in the summer and 6% in the winter. Southwest Power Pool, Submission of Tariff Revisions to Implement Effective Load Carrying Capability Methodology and Performance Based Accreditation, at 17.

reliability becomes a greater concern, regional grid operators are recognizing this issue as well. To that point, PJM recently adjusted its accreditations for coal from 100% to 84% for the 2025–2026 Base Residual Auction (BRA) rules.[15]

Indeed, regional power authorities are the entities with the best local knowledge about performance of both dispatchable and intermittent resources within their region. But FERC also plays a key role, one granted by Congress. Under the Federal Power Act, FERC must approve a regional power authority's accreditation values as a part of reviewing and approving wholesale electricity auction rules within a region.[16] It is curious—if not arbitrary and capricious—for EPA to substitute its judgment on renewable resource performance for that of the federal agency Congress tasked with maintaining grid reliability.

In short, as renewable energy resources have become a more significant part of the grid, regional power authorities are learning how these intermittent resources impact the grid and adjusting their regulatory response accordingly. These trends were beginning when EPA was developing the Final Carbon Rule—although the Agency did not directly acknowledge or discuss them. Rather than addressing comments head-on about rising electricity demands, EPA simply noted that it "performed a variety of sensitivity analyses looking at higher electricity demand."[17] The world is changing rapidly, but EPA's assumptions are not keeping up. This puts the electric grid across the country—not just PJM—in serious risk.

B. <u>EPA's Own Modeled Grid Will Lead to Significant Power Outages and Shortfall Events—Rising Demand Makes these Outages Much Worse.</u>

To truly be able to assert that the grid will be reliable despite the requirements of the Final Carbon Rule, EPA would have needed to conduct its analysis at an hourly rather than annual level. While EPA did not conduct this analysis, MSEH's PJM study does that legwork. MSEH commissioned Energy Ventures Analysis (EVA) to undertake a grid study and analysis. The results

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[15] *ELCC Class Ratings for the 2025/2026 Base Residual Auction*, PJM *available at* https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx. PJM also made adjustments for natural gas combined cycle resources (from 100% to 79%) and natural gas combustion turbine resources (from 100% to 62%).

[16] 16 U.S.C. § 824(d); 18 C.F.R. § 35.13.

[17] EPA's Responses to Public Comments on the Final Carbon Rule, ch. 16, at 20, *docketed as* EPA-HQ-OAR-2023-0072-8914. When responding to comments pointing out EPA's failure to conduct a grid reliability study or the possibility of increased demand, EPA resorted to boilerplate responses. *See, e.g.*, *id.* (The EPA also performed a variety of sensitivity analyses looking at higher electricity demand (load growth) and impact of the EPA's additional regulatory actions affecting the power sector.") The Agency also refers to its IPM Sensitivity Runs Memo, which is notably bereft of serious analysis with respect to resource adequacy. *See* IPM Sensitivity Runs Memo, ch. 3, *docketed as* EPA-HQ-OAR-2023-0072-8917. The memo simply asserts that the model projects that sufficient resources will be constructed.

As noted above, EPA's Resource Adequacy Analysis Technical Memo concedes at the outset that its resource adequacy modeling is merely an "aspect of" grid reliability. EPA, Resource Adequacy Analysis Technical Memo, at 2. The Agency also released a Resource Adequacy Analysis Technical Memo that considers the impact of several rules promulgated by the Agency. While this memo refers to grid modeling conducted by third parties, implicit in the Agency's analysis is that it did not undertake a grid reliability study of its own. EPA, Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR: Technical Memo, 4–7, *docketed as* EPA-HQ-OAR-2023-0072-8915.

demonstrate that the energy resources EPA predicts will exist in the future cannot meet EPA's own demand estimates, let alone increased demand estimates.

EVA analyzed whether the energy resource mix EPA projects through its Integrated Planning Model (referred to as "EPA's 2035 modeled grid") will meet EPA and PJM's predicted demand in EPA's 2035 model year.

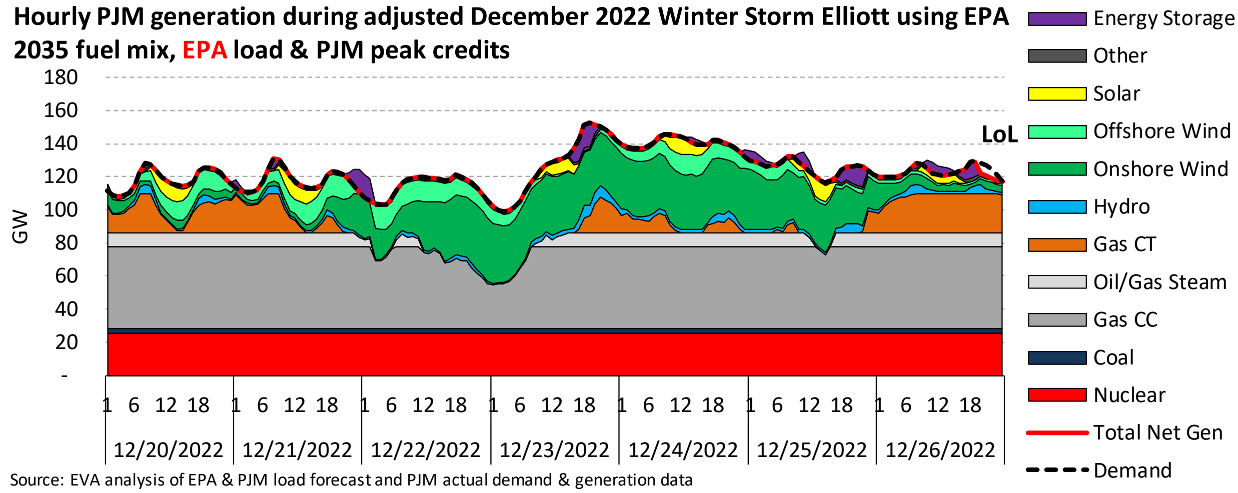
EVA's methodology for analyzing the hourly dispatch of power plant types during high-demand weeks in PJM involves several steps. First, historical hourly data on PJM demand, net generation by fuel type, and power exports/imports are collected from the EIA hourly grid monitor. Wind and solar capacity factors are calculated by dividing actual hourly generation by the installed capacity using data from the U.S. Energy Information Administration's Form EIA-860 dataset. The actual hourly demand is then adjusted based on forecasted peak demand increases for 2022–2035 and 2024–2035 using projections from both the EPA and PJM. Future wind and solar resources are derived by multiplying EPA's projected 2035 wind and solar capacity values with the historical capacity factors determined previously. Assumptions for hourly offshore wind capacity factors during December and June weeks are taken from EPA's modeling assumptions. For the purposes of this modeling exercise, EVA assumed that PJM would not export power to other regions, although historical export averages are considerable.

The maximum available generation by hour for other types of generation (fossil, biomass, geothermal, hydro) is determined by multiplying the EPA's 2035 modeled grid by PJM's capacity credits. Energy storage systems, assumed to be 4-hour lithium-ion batteries, are managed by charging during power surplus and discharging during shortfall. If a power surplus persists after maximizing battery charging, the dispatch of gas turbines (CT), steam turbines (ST), and combined cycles (CC) is sequentially reduced. Finally, the dispatch analysis is performed for both the EPA and PJM load forecasts to compare scenarios and analyze grid reliability.

The shortcomings of EPA's modeled grid are significant. As the EVA study shows: "Using the growth-adjusted Winter Storm Elliott net energy for load and actual renewable resource performance during the event period, modeling results show a [loss of load] LoL duration of 5 hours and 22.5 GWh of unmet demand during a period with little to no expected generation from wind and solar resources."[18] Figure 1 illustrates the shortfall.

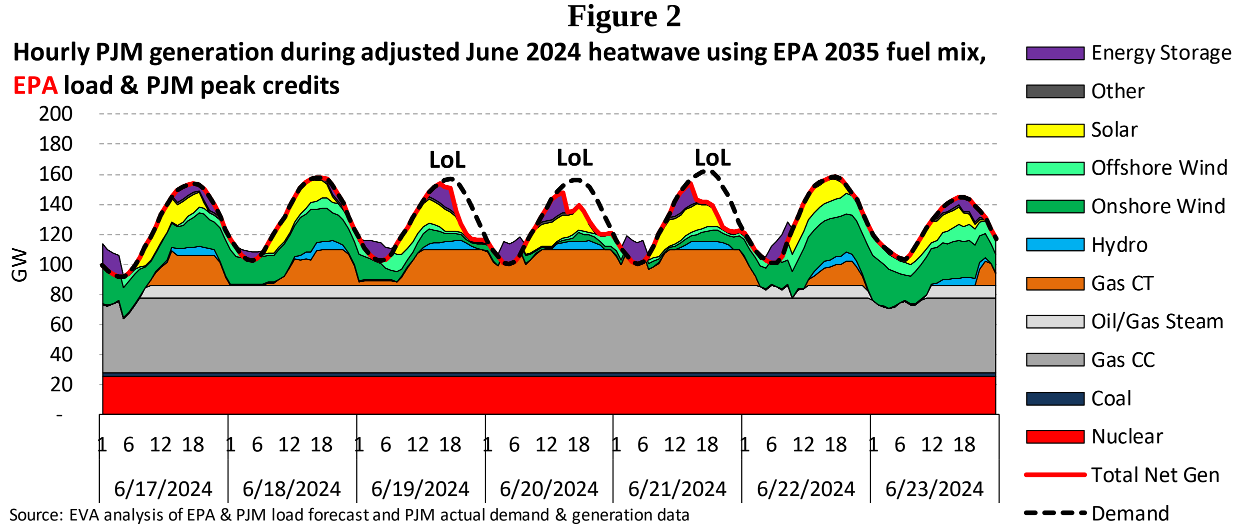
[18] EVA Grid Modeling Study, at 7.

Figure 1



During summer heatwaves, EPA's modeled grid performs even worse against recent weather events. EVA analyzed potential shortfall events during the most recent heatwave in PJM (June 2024) under EPA's 2035 modeled grid. EVA concludes that "Using EPA's 2035 resource mix and real-life observed renewable resource output while also adjusting for the overall increase in demand by 2035, the model showed three separate LoL events totaling 32 hours (19% of all hours analyzed) and over 466 GWh of unmet electricity demand."[19] Figure 2 illustrates these loss of load events.

Figure 2

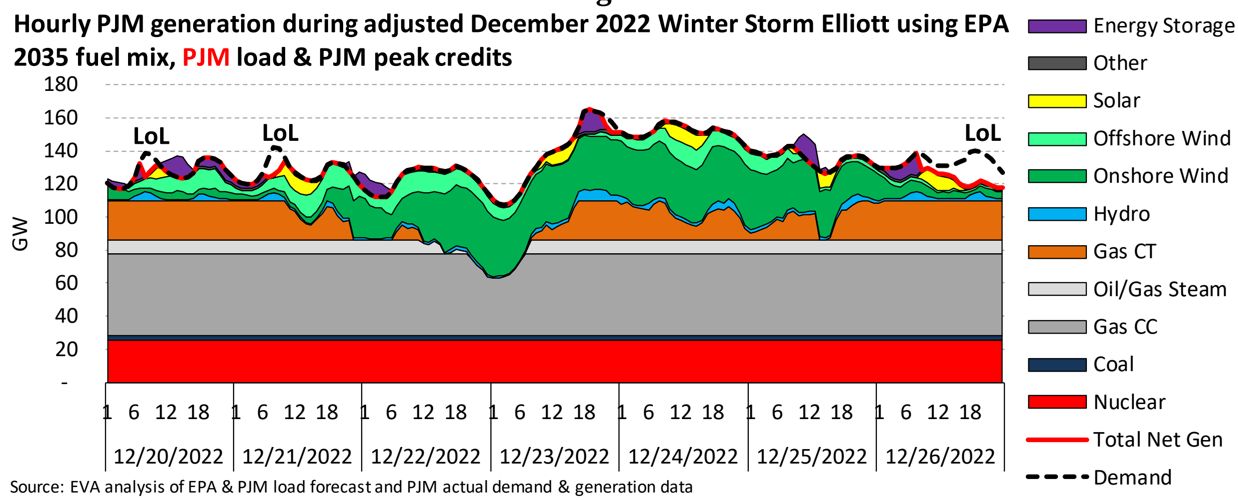


As discussed further below, all regional power authorities have raised their long-term electricity demand forecasts, due to increases in domestic manufacturing, data centers, artificial intelligence processing centers, electric vehicles, and other factors. EVA next analyzed the impact of adjusting the net energy load using PJM's most recent peak demand and load forecast rather than the forecast used by EPA. Under this scenario during Winter Storm Elliott conditions, "dispatch modeling shows the possibility of four individual LoL events, totaling 28 hours (16.7%

[19] EVA Grid Modeling Study, at 8.

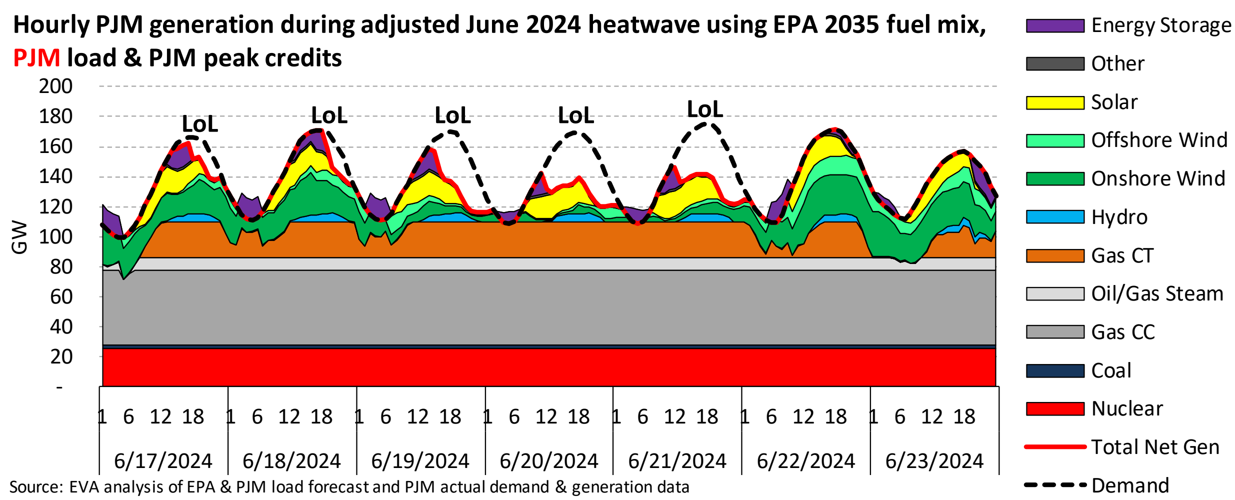
of hours analyzed) and over 273 GWh of unmet electricity demand."[20] These loss of load events are most likely to occur during periods with little to no expected generation from wind and solar resources.

Figure 3



During summer heatwaves, the severity of power outages increases under PJM's increased demand scenario. EVA's analysis "shows the possibility of five individual LoL events, totaling 55 hours (33% of hours analyzed) and over 1,200 GWh of unmet electricity demand."[21] Figure 4 illustrates the severity of these shortfalls.

Figure 4



Demand for electricity is surging around the country, and EVA's modeling for the Final Carbon Rule shows that the grid is not ready to meet this demand. By forcing retirement of existing

[20] EVA Grid Modeling Study, at 7.

[21] EVA Grid Modeling Study, at 8.

dispatchable resources and creating barriers to new reliable, baseload generation, EPA is endangering the grid. New energy resources are needed to meet this new demand.

Indeed, since EPA promulgated the Final Carbon Rule, regional power authorities have been sounding the alarm about dramatic increases in demand for electricity driven by a rise in domestic manufacturing, electric vehicles, data centers, and artificial intelligence processing centers.[22]

During the supplemental comment period for the Final Carbon Rule, this trend had just started to emerge, as was noted by several commenters.[23] However, EPA did not directly address these comments in either the preamble to the Final Carbon Rule or in its separate Response to Comments, save to briefly mention that the Agency considered scenarios with "higher electricity demand."[24]

On January 8, 2024, PJM released its latest long-term load forecast.[25] PJM's most recent load forecast update predicts a significant rise in electricity demand over the next 15 years, with summer peaks growing by 1.7% annually, winter peaks by 2%, and net energy by 2.4%. The key drivers behind these changes include the electrification of transportation and industry, particularly the surge in electric vehicle usage, and the rapid growth of data centers across the PJM region. Historical weather data and new variables for extreme cold weather have refined the forecast models, while extensive stakeholder engagement and public policy integration have informed the projections. This increasing demand underscores the urgent need for adequate generation resources to ensure reliability, highlighting the challenges posed by generator retirements and the slow pace of replacement generation.

PJM's 2024 Load Forecast uses sector-specific models for residential, commercial, and industrial usage, incorporating variables such as weather patterns, economic trends, and end-use efficiencies. The forecast relies on historical data, economic projections from Moody's Analytics (based on September 2023 data), and end-use data from the Energy Information Administration. Adjustments are made for emerging factors like electric vehicle adoption, data center growth, and

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[22] *PJM Summer Outlook: Adequate Resources Available To Meet Summer Demand Under Anticipated Conditions: But Rising Demand Paired With Fewer Resources Continue To Tighten Reserve Levels*, PJM (May 2, 2024), https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20240502-pjm-summer-outlook-adequate-resources-available-to-meet-summer-demand-under-anticipated-conditions.ashx; *ERCOT Enters New Era of Planning to Meet Future Economic Growth*, ERCOT (Apr. 23, 2024), https://www.ercot.com/news/release/2024-04-23-ercot-enters-new ("'As a result of Texas' continued strong economic growth, new load is being added to the ERCOT system faster and in greater amounts than ever before,' said ERCOT President and CEO Pablo Vegas."); *OMS-MISO survey results indicate tight resource capacity in the upcoming planning year*, MISO (Jun. 20, 2024), https://www.misoenergy.org/meet-miso/media-center/2024/oms-miso-survey-results-indicate-tight-resource-capacity-in-the-upcoming-planning-year/; *see generally* 2023 FERC Reliability Technical Conference (Nov. 9, 2023), *docketed as* AD23-9-000.

[23] Cato Institute, Comment Letter on the Supplemental Notice of Proposed Rulemaking for the EPA Carbon Rule, 3–4 (Dec. 20, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-8213; National Mining Association, Comment Letter on the Supplemental Notice of Proposed Rulemaking for the EPA Carbon Rule, 19–20 (Dec. 20, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-8195.

[24] *See* Final Carbon Rule, 89 Fed. Reg. 39,803.

[25] *PJM Load Forecast Report* (Jan. 2024), PJM Interconnect, *available at* https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

state policies on electrification. The methodology includes simulating load scenarios based on 29 years of weather data and adjusting for peak-shaving programs and distributed energy resources to ensure accurate and reliable demand forecasts.

This new electricity demand reality—as shown in PJM's 2024 demand study—stands in stark contrast to the PJM demand forecast EPA used in the Final Carbon Rule. In short, EVA concluded that "[d]ue to the recent massive growth in electricity demand from data centers across the PJM footprint, the ISO revised its peak demand and energy load forecast upward considerably from its forecast issued just a year ago,"[26] meaning that "EPA's underlying PJM peak demand and energy load forecast are no longer in line with the ISO's latest demand projections."[27]

Figure 5

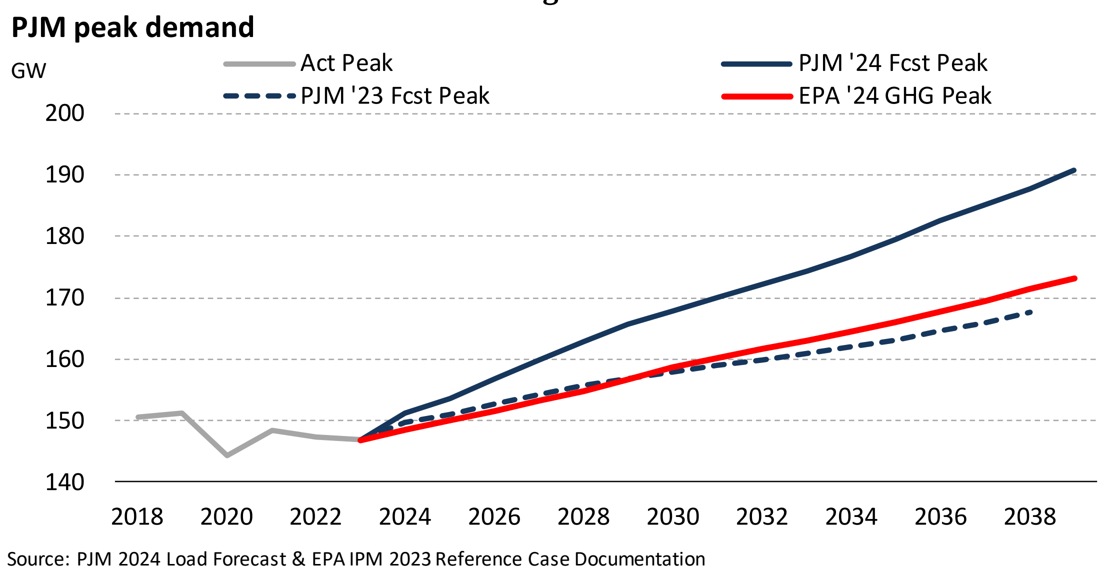

Figure 5 illustrates that PJM's revised demand projections leads to a significant difference by 2040. PJM is currently projecting demand to be 6% higher than EPA's assumptions in 2030 and 11% higher in 2040. As will be discussed below, this increase in demand has significant implications for grid reliability.

In late May 2024, a new study focused on PJM projected significant increases in electricity demand for 2030 and 2040.[28] The study developed two scenarios for PJM: an expected scenario and a high scenario. The expected scenario represents the study authors' best estimate; the high scenario "represents a future with greater energy needs due to accelerated electrification, more generator retirements, and clean energy demand."[29] The study states PJM's load "could increase

[26] Energy Ventures Analysis, *Analysis of EPA's PJM Modeling as Part of the GHG Rule*, 5 (Jul. 25, 2024) (EVA Grid Modeling Study) (included as Attachment 1).

[27] *Id.*

[28] Zach Zimmerman et al., *Transmission Planning for PJM's Future Load and Generation Version 1*, Americans for a Clean Energy Grid, 12 (May 2024) *available at* https://gridstrategiesllc.com/wp-content/uploads/GS_Transmission-Planning-for-PJMs-Future.pdf.

[29] *Id.*

by almost 50 percent over the next 15 years, or an additional 421 TWh."[30] This would add 90 TWh above PJM's current forecast for 2024.

Considering both load growth and retirements of units, the projected resource gap represents more than half of the total load in 2040 under both the expected and high scenarios. Thus, to meet expected load, more than half of all energy resources will need to be new construction. PJM has not yet incorporated these estimates into its published load growth forecasts, but as new information about electricity demand continues to unfold, there is reason to believe that PJM's estimates may be increased further.

Since EPA published the Final Carbon Rule, the data has become clearer and more concrete: demand for electricity in the U.S. is on the rise and the grid is at risk. That is particularly problematic because EPA's Final Carbon Rule establishes a 40% "baseload" threshold for new gas-fired EGUs. New, highly efficient baseload units are needed immediately to maintain grid reliability for years to come.

Bottom line, baseload plants will play a critical role in an evolving grid with increasing demand and an influx of weather-dependent, intermittent resources, making it more important than ever for operators to develop new baseload, weather-resilient plants—and soon.

II. EPA's Final Carbon Rule Applies to More Base Load Combustion Turbines than Proposed, and Thereby Threatens the Grid.

The Final Carbon Rule applies to more combustion turbines, and much sooner, than what EPA had proposed. This change will exacerbate grid reliability problems. Furthermore, the shorter compliance timeline was not capable of being commented on during the comment period because EPA did not propose, request comment on, or even hint at a shorter compliance deadline. This, in and of itself, warrants reconsideration.

EPA proposed to treat combined cycle turbines operating at capacity factors of greater than 50% as base load.[31] EPA expects there to be considerable interest in building intermediate load and low load combustion turbines to meet demand for dispatchable generation, and thus EPA projects no reliability impacts, but EPA has now narrowed the universe of intermittent load turbines by expanding the universe of base load turbines. Some turbines that were proposed to be treated as intermediate load will now be treated as base load under the Final Carbon Rule and thereby burdened by an unproven standard based on 90% capture of CO_2—and thus they may never be built at all.

EPA proposed to require new base load combustion turbines to meet a standard based on 90% capture of CO_2 by 2035.[32] But in the Final Carbon Rule, EPA is compelling compliance by

[30] *Id.* at 13.

[31] *See, e.g.*, EPA Proposed Carbon Rule, 88 Fed. Reg. 33,240, 33,322 (May 23, 2023); *see also Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units*, EPA 8, https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf.

[32] EPA Proposed Carbon Rule, 88 Fed. Reg. at 33,322.

2032.[33] EPA recognized in the proposal that pre-2035 compliance for combustion turbines would be a stretch. EPA justified the 2035 date in the proposal based on "overlapping demands on the capacity to design, construct, and operate carbon capture systems as well as pipeline systems that would potentially be needed to support CCS projects for existing steam generating units and other industrial sources."[34] Yet EPA advanced the compliance date to 2032 in the Final Carbon Rule. CCS has not been adequately demonstrated for combustion turbines. EPA set its 90% CO_2 capture standard based on CCS availability for coal plants and the Bellingham Cogeneration Facility, neither of which give any confidence that combustion turbine CCS will be available by 2035, let alone 2032.

EPA mistakenly believes that CCS for combustion turbines is easier than CCS for coal: "Where differences exist, due to differences in flue gas composition, CCS at natural gas-fired combined cycle combustion turbines will in general face fewer challenges than CCS at coal-fired steam generators. . . . As a result, for CO2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (e.g., heat exchangers)."[35] That conflicts with EPA's prior view and is at odds with the common held industry view. When promulgating the Clean Power Plan, EPA specifically evaluated the appropriateness of CCS as BSER for new natural gas-fired stationary combustion turbines.[36] EPA stated: "We do not consider full or partial capture CCS to be BSER because of insufficient information to determine technical feasibility and because of adverse impact on electricity prices and the structure of the electric power sector."[37] EPA provided numerous bases for this determination. Specifically, EPA explained "[t]here are significant differences between natural gas-fired combustion turbines and solid fossil fuel-fired EGUs[.]"[38] For example, the concentration of CO2 in flue gas from natural gas combined cycle (NGCC) units is lower than that from coal-fired units, therefore "the overall amount of CO2 that can be captured in a CCS project [at an NGCC] is likely lower."[39] It also conflicts with the administrative record, where commenters (including turbine manufacturers) said the opposite, as follows:

- "[R]esearch and testing of amine technologies for CO2 removal on gas-fired stationary combustion turbines have only recently begun."[40] "Amine technologies for CO2 removal in the CCUS process are commercially available for coal-fired EGUs, and multiple companies are purportedly willing to offer commercial guarantees on solvent performance. However, research and testing of amine technologies for CO2 removal on gas-fired EGUs have only begun."[41]

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[33] Final Carbon Rule, 89 Fed. Reg. at 39,802.

[34] *Id.* at 39,938.

[35] *Id.* at 39,926.

[36] *See* EPA Proposed Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430, 1,485 (Jan. 8, 2014).

[37] *Id.*

[38] *Id.*

[39] *Id.*

[40] Class of '85 Regulatory Response Group, Comment Letter on EPA's Proposed Carbon Rule, 22 (Aug. 8, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0577.

[41] *Id*. at 9.

- "[I]t is unclear whether the variable operating conditions of gas-fired stationary combustion turbines can support CCS, much less at the level of CO2 removal set by EPA as BSER. Such EGUs need to quickly respond to support more flexible electric generating scenarios, which entail a wide range of operating conditions, including high ramping rates, periods of minimum load operations, and the potential for multiple startups and shutdowns of the unit per day. Additionally, CCS technology would require energy from the combustion turbines to operate, which would decrease the efficiency of the combustion turbine, decrease the unit's contribution to serving load requirements for system reliability, and potentially delay broader economy-wide decarbonization by reducing electrification opportunities."[42]

- "Should CCUS eventually be adequately demonstrated for gas-fired EGUs, there are still additional hurdles. CCUS would substantially increase the costs associated with constructing a new gas-fired CT facility, potentially making many such projects uneconomical. It could instead lead to a delay in transitioning the industry to cleaner generation. Companies might choose not to install newer, hydrogen capable gas fired CTs if they also were forced to install CCUS. Carbon sequestration technology also might require energy for directing steam from a combined cycle CTs HRSG to the carbon capture unit to operate. This would require the CT to fire more gas and produce a lower overall amount of net electricity for the grid, thus reducing the efficiency of the CT, and would result in an increase in upstream emissions from gas production and transport associated with increased gas utilization. Additionally, when using CCUS on combined cycle CTs, there are reductions in the CTs operating range. Current research and engineering evaluations are focused on addressing this issue, but such results to date have not been demonstrated."[43]

- "The power industry's current focus on [post-combustion carbon capture] PCCC technology for natural gas combined-cycle EGUs uses a CO2 attractive compound (liquid solvent or solid sorbent) to capture CO2, which then must be dried and compressed for transportation to a storage facility. To date, this liquid solvent technology has not been commercially demonstrated at full scale on a large natural gas combined-cycle EGU, and will not be for years. Additionally, there may be times of grid stress where the EGU power used to serve internal load for capture operations would be better served by providing unabated power to the balancing authority. Potential non-compliance with a Clean Air Act performance standard is a serious issue for an EGU owner or operator."[44]

[42] *Id*. at 22.

[43] *Id*. at 10.

[44] GE Vernova, Comment Letter on EPA Proposed Carbon Rule, 35 (Aug. 8, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0722.

REQUEST TO WITHDRAW AND RE-PROPOSE THE FINAL CARBON RULE WITH RESPECT TO FULLY PERMITTED NGCCS

PJM's new electricity demand projects and EVA's grid assessment demonstrate that EPA's grid reliability assumptions and conclusions are unrealistic. In light of how the Final Carbon Rule jeopardizes future construction of any base load natural gas combustion turbines, such as MSCE's project, EPA must allow the development and construction of new combustion turbines in the Final Carbon Rule to support grid reliability.

To achieve this, EPA should rescind the Final Carbon Rule with respect to natural gas-fired combustion turbines that have been permitted but not yet constructed—a relatively small number of units. This modification would allow these units to move forward without being subject to the Final Carbon Rule.

Alternatively, EPA should exclude from the Final Carbon Rule those hydrogen-capable natural gas turbines that are already permitted and re-propose standards for them alongside the under development existing source standards. This discrete class of turbines, such as MSCE's, can be built in the near term and will help solve grid reliability concerns. In its 2012 new source performance standards for greenhouse gas emissions, EPA created a "transitional source" category. Specifically, sources that had acquired a complete preconstruction permit by the time of the proposal and that commenced construction within 12 months of the proposal would not be "affected sources" under the 111(b) standards as proposed and therefore would not have had to comply with new source standards.[45] Similarly, in its 2014 new source performance standards proposal, EPA noted that the Wolverine EGU project was under development, that it would not meet the proposed 1,100 lb CO_2/MWh standard applicable to new sources, and that, if the project developer had not commenced construction at the time of finalization of the proposed standards, EPA "anticipated proposing a standard of performance specifically for that facility."[46] The discussion above should make clear that there is a compelling rationale for treating fully permitted, hydrogen-capable combustion turbines similarly.

CONCLUSION

EPA has created a grid reliability crisis through the Final Carbon Rule, a crisis that will be deepened as it issues new regulations for existing oil- and gas-fired EGUs. To address this crisis, EPA should amend or rescind the Final Carbon Rule with respect to those gas-fired combustion turbines that have been permitted but not yet constructed to ensure that the increasing demands on the grid can be met and the growing reliability and resilience risks in the grid can be mitigated. The consequences of EPA continuing down its current course without alteration will ultimately be tragic, and likely fatal.

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[45] *See, e.g.*, EPA Proposed Standards of Performance for GHG Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392, 22,395 (Apr. 13, 2012).

[46] EPA Standards of Performance for GHG Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510, 64,542 (Oct. 23, 2015); *see also* EPA Proposed Standards of Performance for GHG Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. at 1,461.

Respectfully submitted,

By: /Stephen Nelson/
Stephen Nelson
CEO
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ATTACHMENT 1

ANALYSIS OF EPA'S PJM MODELING AS PART OF THE GHG RULE

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Executive Summary

- EPA’s recently finalized environmental rules have the potential to significantly alter PJM’s future resource mix while increasing the likelihood and duration of so-called Loss-of-Load (LoL) events.
- Due to the underlying limitations of EPA’s electric power modeling platform, the results of EPA’s GHG rule impact modeling heavily prioritize the build-out of intermittent renewable energy resources while underestimating the reliability impacts associated with a grid heavily reliant on these types of resources.
- By 2050, EPA projects a decline of over 50% in PJM baseload generating capacity while wind and solar resources grow 11x and 9x compared to 2023 levels.
- The recent unprecedented growth in data center electricity demand across the PJM footprint also makes EPA’s underlying PJM peak electricity demand and net energy load forecast outdated.
- Additionally, PJM’s recent adjustments to the peak capacity credits for its various resources would render EPA’s resulting 2035 resource mix inadequate to meet its own and especially PJM’s updated peak electricity demand forecast.
- EPA’s model is also insufficient to accurately model possible reliability impacts of its projected future resource mix. Actual (albeit high-level) dispatch modeling showcases the possible likelihood of LoL events during recent peak electricity demand periods affecting the PJM power market (i.e., Winter Storm Elliott and June 2024 Heatwave).
- Lastly, EPA’s other recently finalized environmental regulations, such as the MATS and ELG updates, could result in accelerated PJM coal plant retirements over the next decade regardless of the eventual fate of EPA’s GHG rule.

EPA's Greenhouse Gas (GHG) rule will have force major changes to the U.S. power grid over the next decade

Existing Fossil Resources

- **Fossil-Steam EGUs**
  - **Coal-Steam EGUs**
    - **Imminent Retirement** *(retire before 2032)*
      - Exempt from rule
    - **Medium-term Retirement** *(retire before 2039)*
      - 16% ER reduction starting in 2030 based on co-fire 40% natural gas
    - **Long-term Retirement** *(retire after 2038)*
      - 88.4% ER reduction starting in 2032 based on 90% CCS
- **Oil/Gas-Steam EGUs**
  - Low-load (<8% CF): maintain baseline ER
  - Intermediate Load (8% < CF < 45%): 1,500 lbs CO_2/MWh (~13 HR for NG)
  - Baseload (>45% CF): 1,300 lbs CO_2/MWh
  - Limits starting in 2030 (~11.6 HR for NG)
- **Combustion Turbines**
  - Not included in rule

ER = CO_2 emission rate
MWh = gross generation

New Resources

- **Fossil-Steam EGUs**
  - No change from 2014 NSPS
- **Combustion Turbines**
  - **Low load** *(CF < 20%)*
    - <160 lbs CO_2/MMBtu based on fuel
  - **Intermediate load** *(20% < CF < 40%)*
    - 1,170 lbs CO_2/MWh based on highly efficient CT design (CC possible)
      - ~9.8 HR on NG
  - **Baseload** *(>40% CF)*
    - 800-900 lbs CO2/MWh based on highly efficient CCGT design (~6.6 HR on NG)
    - **CCS Pathway**
      - 100 lbs CO_2/MWh starting in 2032 based on 90% CCS

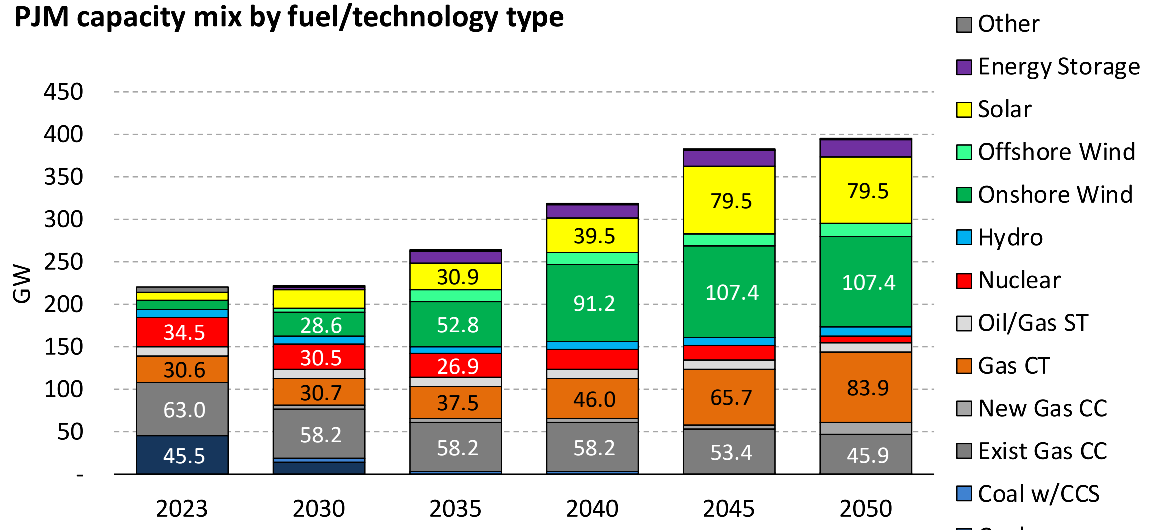
MWh = gross generation

- EPA's 2024 finalized GHG rule will require existing coal-fired steam electric generating units (EGUs) to convert to co-firing 40% natural gas by 2030 while also agreeing to retire by 2039, or retrofit carbon capture and sequestration (CCS) technology or retire by 2032
- Since existing oil or natural gas steam EGUs have no retirement requirement, it is likely that many coal-fired EGUs elect to convert to 100% natural gas before 2030 to avoid having to make retirement or CCS retrofit decisions within the next two years

- EPA's final GHG rule also includes updated New Source Performance Standards (NSPS) for new stationary combustion turbines
- Depending on the annual utilization of these combustion turbines, different CO_2 emission rate standards apply
- Most notably, high-utilization CTs (i.e., baseload combined cycle plants) are required to retrofit 90% CCS by 2032
- Also, existing CTs are not covered by the final GHG rule and will be addressed in a separate rulemaking

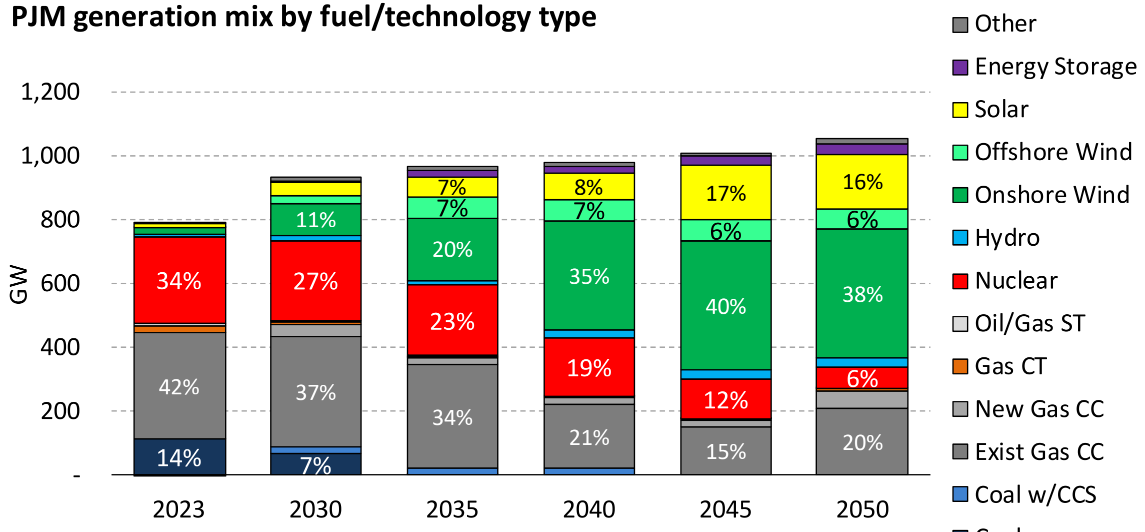
PJM's capacity & generation mix relies heavily on intermittent resources in EPA's GHG modeling results

PJM capacity mix by fuel/technology type



Source: EIA 860 data & EPA GHG model results

PJM generation mix by fuel/technology type

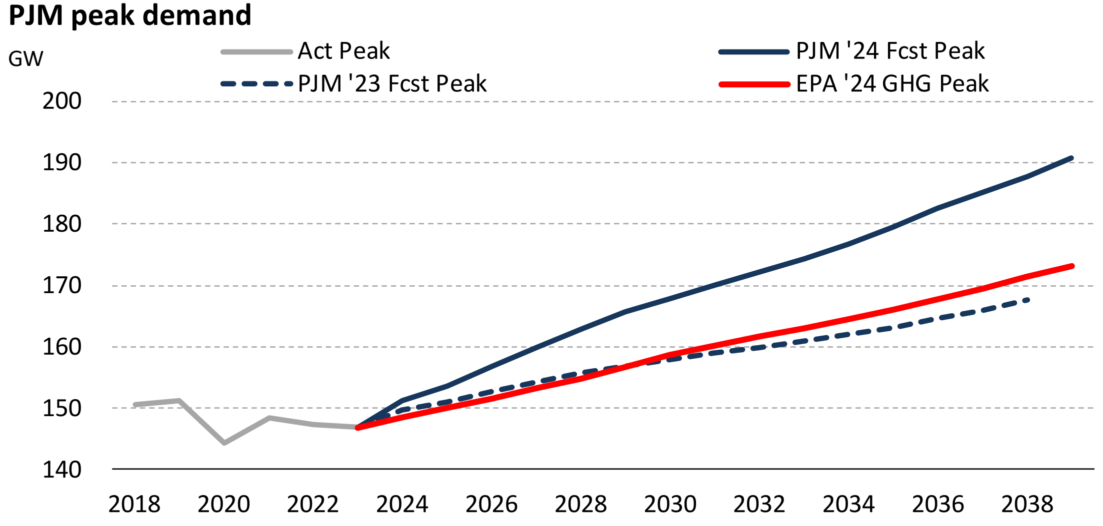


Source: EIA 923 data & EPA GHG model results

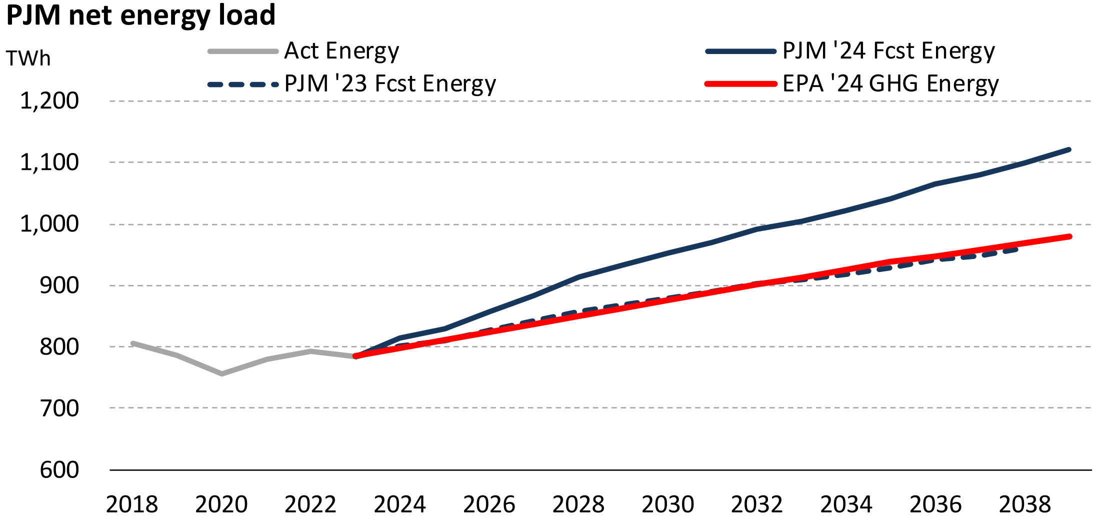
- As part of EPA's rulemaking process, the agency forecasted PJM's capacity and generation mix under the GHG rule using its IPM platform
- Driven by an increase in electric load (i.e., demand) and heavily subsidized intermittent renewable resources, PJM's overall capacity is projected to nearly double between 2023 and 2050
- While baseload fossil fuel EGUs are projected to retire at alarmingly fast rates (-50% from 2023 to 2050), EPA's model massively expands wind (11x) and solar capacity (9x), backed up by energy storage and simple cycle combustion turbines

- Due to the model limitations of EPA's IPM model (i.e., it is not an hourly electric dispatch model), EPA's resulting generation mix is also heavily tilted towards intermittent renewable resources such as wind and solar
- Accounting for less than 5% of total generation in 2023, wind and solar combine to provide more than 60% of PJM's generation by 2050
- Natural gas, nuclear, and coal are reduced to providing balancing support for the intermittent wind and solar resources, providing less than one-third of PJM's generation in 2050

EPA's PJM demand forecast is well below PJM's latest demand projections



Source: PJM 2024 Load Forecast & EPA IPM 2023 Reference Case Documentation



Source: PJM 2024 Load Forecast & EPA IPM 2023 Reference Case Documentation

- Due to the vintage of EPA's modeling inputs used for its GHG rule impact modeling, EPA's underlying PJM peak demand and energy load forecast are no longer in line with the ISO's latest demand projections
- Due to the recent massive growth in electricity demand from data centers across the PJM footprint, the ISO revised its peak demand and energy load forecast upward considerably from its forecast issued just a year ago

- According to PJM's latest forecast, the ISO expects peak demand to grow from about 151 GW in 2024 to 190 GW by 2039, a 1.5% CAGR (compared to a CAGR of -0.5% for the period of 2018 - 2023)
- Similarly, the total net energy load is also projected to grow by over 26% between 2023 and 2039 (2.2% CAGR), compared to a net decline in electricity demand from 2018 to 2023

EPA's modeled capacity credits do not align with real-world observations & PJM's most recent assumptions

	EPA GHG Model	PJM '24/'25 BRA	PJM '25/'26 BRA	Latest PJM vs. EPA
Coal	100%	100%	84%	-16%
NGCC	100%	100%	79%	-21%
NGCT	100%	100%	62%	-38%
Diesel Utility	100%	100%	92%	-8%
Oil/Gas Steam	100%	100%	75%	-25%
Nuclear	100%	100%	95%	-5%
Onshore Wind	26%	21%	35%	9%
Offshore Wind	7%	47%	60%	53%
Solar (Tracking)	9%	50%	14%	5%
Landfill	100%	36%	54%	-46%
Hydro	77%	61%	37%	-40%
Energy Storage (4hr)	96%	92%	59%	-37%

	2028	2030	2035	2040	2045	2050
Capacity using EPA peak credits	176.8	177.1	183.6	197.5	210.2	222.8
EPA PJM demand	154.8	158.7	165.9	175.0	187.6	202.2
Reserve Margin (%)	*14.2%*	*11.6%*	*10.6%*	*12.8%*	*12.1%*	*10.2%*
Capacity using PJM peak credits	144.9	144.4	153.9	171.9	184.5	190.2
EPA PJM demand	154.8	158.7	165.9	175.0	187.6	202.2
Reserve Margin (%)	*-6.4%*	*-9.0%*	*-7.3%*	*-1.8%*	*-1.7%*	*-6.0%*
Capacity using PJM peak credits	144.9	144.4	153.9	171.9	n/a*	n/a*
PJM '25/'26 demand	163.0	167.9	179.6	193.4	n/a*	n/a*
Reserve Margin (%)	*-11.1%*	*-14.0%*	*-14.3%*	*-11.1%*	*n/a**	*n/a**

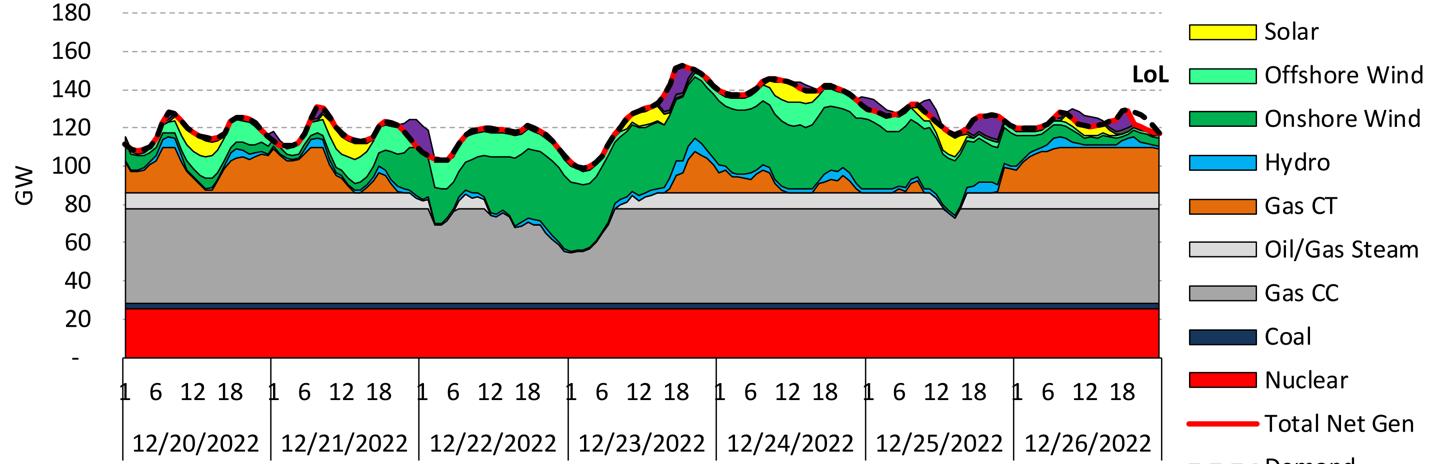
** PJM '25/'26 demand forecast ends in 2039; 2040 estimated, no estimation for 2045 or 2050*

- To ensure sufficient capacity available to meet the forecast peak electricity demand, utilities and ISOs assign so-called peak credits to different EGUs based on the fuel or technology they use
- In preparation for its upcoming capacity auction, PJM revised its peak credit assumptions to account for the observed availability of different EGU types during the most recent peak electricity demand events
- Most notably, PJM reduced the peak credits for fossil fuel-fired EGUs while also reducing the contribution of solar resources during peak demand events

- To ensure adequate capacity is available during peak electricity demand events, PJM establishes so-called reserve margin targets (peak-credit adjusted installed capacity divided by forecasted peak demand)
- Unsurprisingly, EPA's model showcases an adequate reserve margin of over 10% for all modeled years since the reserve margin is one (of many) of the model constraints incorporated
- However, when adjusting the EPA's modeled capacity mix by PJM's updated peak credits and peak demand forecast, the reserve margins quickly fall well below projected peak demand, highlighting an increased risk to reliability across the PJM market

EPA's projected PJM energy resource mix will increase Loss-of-Load probabilities during peak demand periods

Hourly PJM generation during adjusted December 2022 Winter Storm Elliott using EPA 2035 fuel mix, EPA load & PJM peak credits

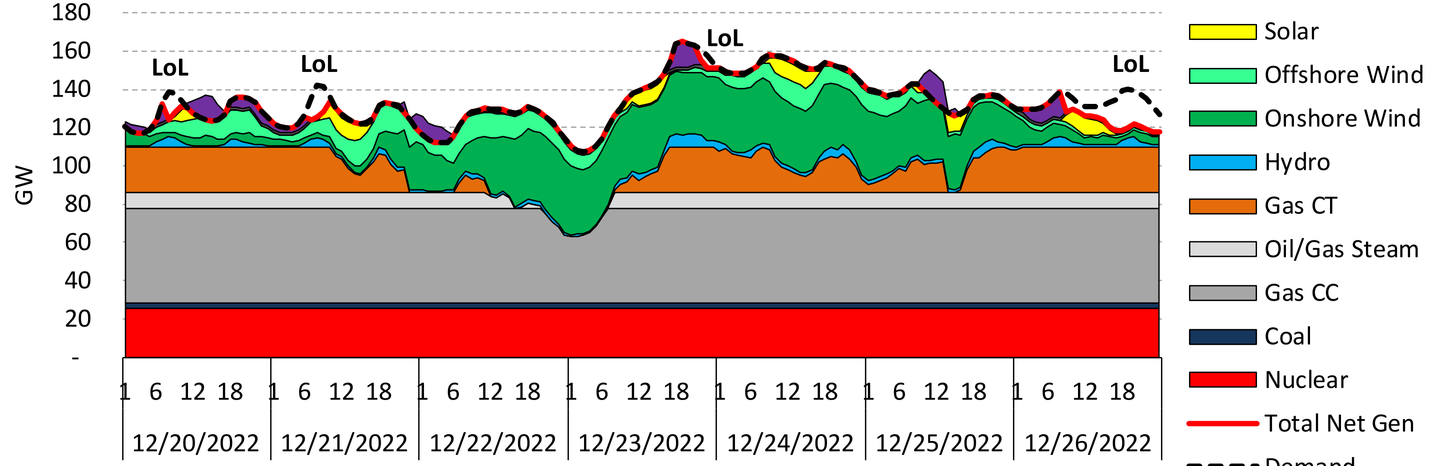


Source: EVA analysis of EPA & PJM load forecast and PJM actual demand & generation data

LoL = Loss of Load event

- EPA's electric power dispatch modeling shortcomings become apparent when its forecasted resource mix is applied to recent peak electricity demand periods in PJM
- Using the growth-adjusted Winter Storm Elliott net energy for load and actual renewable resource performance during the event period, modeling results show a LoL duration of 5 hours and 22.5 GWh of unmet demand during a period with little to no expected generation from wind and solar resources

Hourly PJM generation during adjusted December 2022 Winter Storm Elliott using EPA 2035 fuel mix, PJM load & PJM peak credits



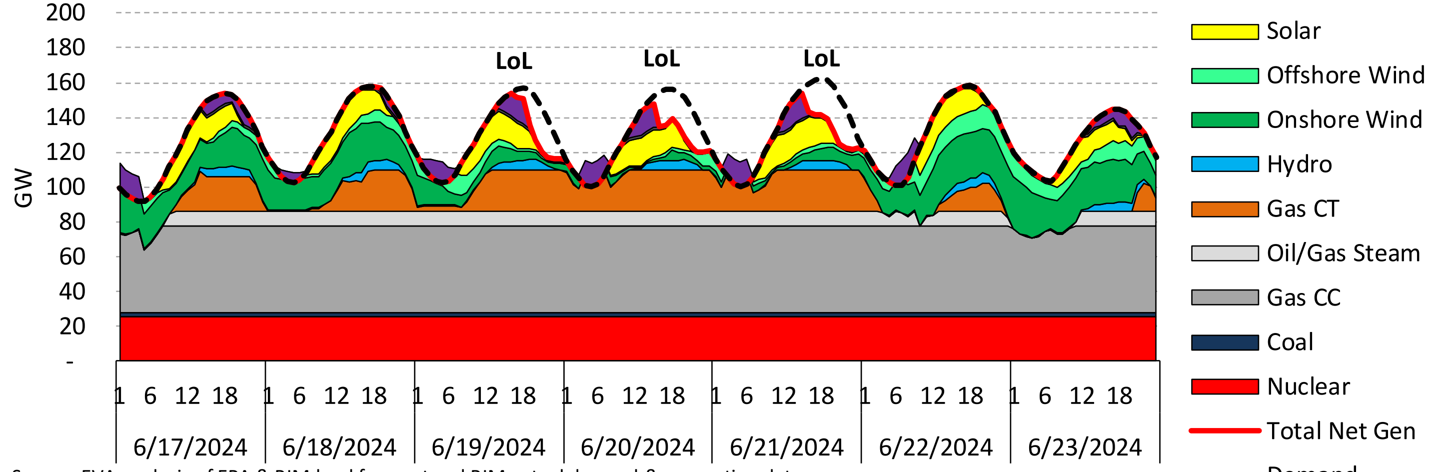
Source: EVA analysis of EPA & PJM load forecast and PJM actual demand & generation data

LoL = Loss of Load event

- When adjusting the net energy for load using PJM's most recent peak demand and load forecast, initial dispatch modeling shows the possibility of four individual LoL events, totaling 28 hours (16.7% of hours analyzed) and over 273 GWh of unmet electricity demand
- Once again, the LoL events are most likely to occur during periods with little to no expected generation from wind and solar resources

EPA's projected PJM energy resource mix is inadequate to meet peak electricity demand periods during summer heatwaves

Hourly PJM generation during adjusted June 2024 heatwave using EPA 2035 fuel mix, EPA load & PJM peak credits

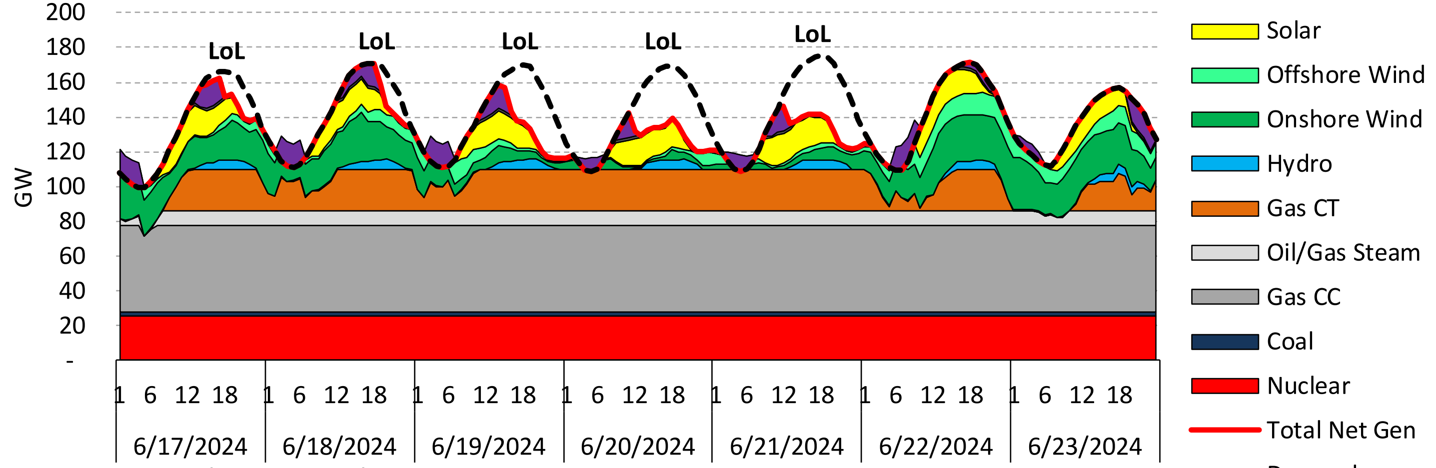


Source: EVA analysis of EPA & PJM load forecast and PJM actual demand & generation data

LoL = Loss of Load event

- In addition to the peak demand period during Winter Storm Elliott, EVA also analyzed possible LoL events during the most recent heatwave impacting PJM in June 2024 under EPA's projected 2035 resource mix
- Using EPA's 2035 resource mix and real-life observed renewable resource output while also adjusting for the overall increase in demand by 2035, the model showed three separate LoL events totaling 32 hours(19% of all hours) and over 466 GWh of unmet electricity demand

Hourly PJM generation during adjusted June 2024 heatwave using EPA 2035 fuel mix, PJM load & PJM peak credits



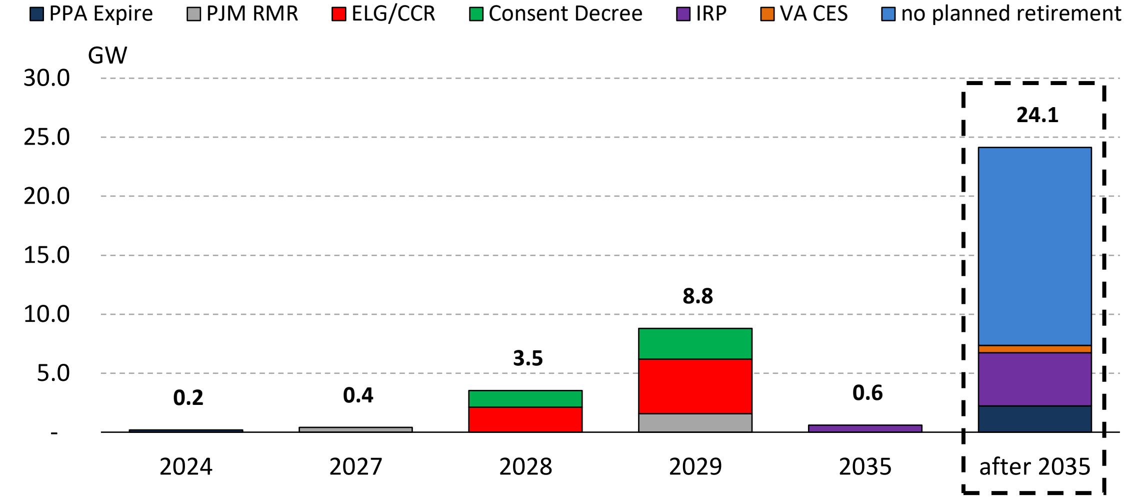
Source: EVA analysis of EPA & PJM load forecast and PJM actual demand & generation data

LoL = Loss of Load event

- When adjusting the net energy for load using PJM's most recent peak demand and load forecast, initial dispatch modeling shows the possibility of five individual LoL events, totaling 55 hours (33% of hours analyzed) and over 1,200 GWh of unmet electricity demand
- The LoL events are most likely to occur during evening and early night hours when heat-induced electricity demand remains high but little to no solar and wind generation is available, and backup generation is inadequate to replace the sudden loss in solar generation

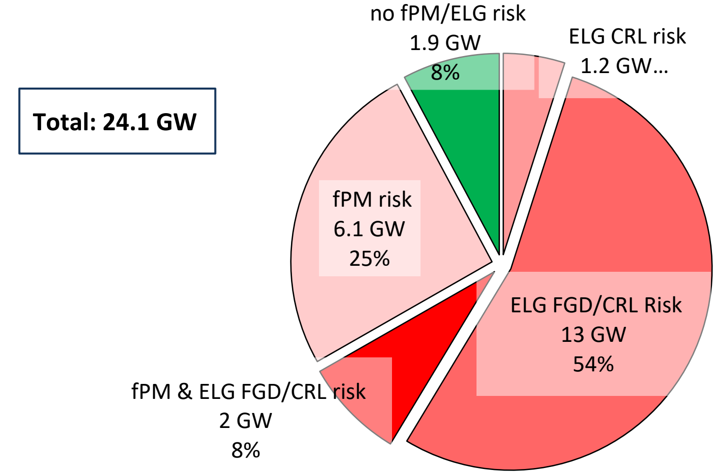
EPA's other recently finalized environmental rules will also significantly impact PJM's future resource mix

PJM coal unit retirement by year and cause



Source: EVA analysis pf company announcements & IRPs

PJM coal units @ risk of accelerated retirement due to new EPA MATS/ELG rules



Source: EVA analysis of power plant emission & environmental control data

- Besides the highly-covered GHG rule, EPA also finalized stricter Mercury and Air Toxics Standards (MATS) and Effluent Limitation Guidelines (ELG) for coal-fired power plants, with compliance dates by 2027 and 2029, respectively
  - EPA's MATS update includes a reduced filterable particulate matter (PM2.5) limit, while the updated ELGs require zero-liquid discharge for bottom ash and SO_2 scrubber wastewater and treatment of coal ash landfill water runoff

- About 13.5 GW (~35%) of PJM's current coal fleet are announced to retire over the next decade, while the other two-thirds (~24 GW) do not have plans to retire before 2035
- However, EPA's recently finalized updates to the MATS and ELG rules put over 90% (22 of 24 GW) of the coal fleet with no retirement plans before 2035 at risk of accelerated or early retirement

Sources

- EPA GHG rule: https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power
- EPA MATS rule update: https://www.epa.gov/stationary-sources-air-pollution/final-rule-national-emission-standards-hazardous-air-pollutants-0
- EPA ELG update: https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2024-final-rule
- EPA IPM results: https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines
- PJM load forecast: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process
- PJM ELCC information: https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability
- PJM hourly generation data: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/PJM
- EIA 860 data: https://www.eia.gov/electricity/data/eia860/
- EIA 923 data: https://www.eia.gov/electricity/data/eia923/
- EPA fPM data: https://www.epa.gov/air-emissions-inventories/2020-national-emissions-inventory-nei-data

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Appendix: Hourly Dispatch Analysis Methodology

1. Download hourly PJM data (demand, net generation by fuel type, power (ex)/imports) from EIA hourly grid monitor
2. Calculate wind and solar capacity factor during the analyzed week by dividing actual hourly wind/solar generation by installed wind/solar capacity in PJM during that time (data from EIA 860 data)
3. Adjust actual hourly demand for the analyzed week by the forecasted increase in peak demand between 2022/2024 and 2035 with EPA's PJM peak demand forecast and PJM's latest peak demand forecast
   1. 2022 -> 2035 (EPA): 13% increase; 2024 -> 2035 (EPA): 10% increase
   2. 2022 -> 2035 (PJM): 22% increase; 2024 -> 2035 (PJM): 19% increase
4. Multiply calculated wind and solar capacity factor from (2) with EPA projected 2035 wind and solar capacity factor
   1. Use EPA model assumption for PJM hourly offshore wind capacity factor during the December/June weeks
5. Assume no PJM power exports (i.e., PJM net generation = demand)
   1. PJM exported an average of 3.6 GW per hour during Winter Storm Elliott and 4.3 GW during the June 2024 heatwave
6. Multiply EPA projected 20235 capacity for all other generation types (fossil, biomass, geothermal, hydro) by the '25/'26 PJM BRA capacity credits to get maximum available generation by hour from these resources
7. Charge/discharge energy storage systems (assumed to be 4-hour li-ion battery systems) during hours of power surplus/shortfall
8. Reduce dispatch of other resources (gas CT -> gas ST -> gas CC) when power surplus persists after maximizing battery charging
9. Do the dispatch analysis for both load forecasts (EPA vs. PJM – see (3))