UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	))))	Docket No. ER25-1357-000

PROTEST OF AMERICA'S POWER

Reliability and resource adequacy rather than price suppression should be the focus of any just and reasonable PJM Interconnection, L.L.C. ("PJM") Federal Power Act ("FPA") Section 205[1] proposals to the Federal Energy Regulatory Commission ("Commission") because PJM bears a responsibility to ensure "that its system has sufficient generating capacity to meet its reliability obligations."[2] A laser-sharp focus on reliability and resource adequacy is particularly crucial in light of the impending near-term threat of a capacity shortfall in PJM that PJM explicitly recognizes in its February 20, 2025 filing in the above-captioned docket.[3] Yet in the PJM Price Cap Proposal that is the subject of this protest, PJM seeks to impede market forces from operating as intended. It would stunt the signal for existing

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[1] 16 U.S.C. § 824d.

[2] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 2 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,318 (2007), *reh'g denied*, 121 FERC ¶ 61,173 (2007), *aff'd sub nom.*, *Pub. Serv. Elec. & Gas Co. v. FERC*, 324 Fed. Appx. 1 (D.C. Cir. 2009). As recently stated by Commissioner Chang, "[t]he Commission and PJM have a paramount obligation to ensure that PJM's system reliably serves its load." *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025), dissenting opinion of Commissioner Chang at P 2.

[3] *PJM Interconnection, L.L.C.*, Docket No. ER25-1357-000, Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date (Feb. 20, 2025)("PJM Price Cap Proposal"), Transmittal Letter at 22 (acknowledging that "[t]he PJM Region is at or near capacity shortage conditions. . .").

capacity to continue operating and to make new investments, as well as to incent planned capacity to remain in the queue, by imposing a price cap of approximately $325/MW-day in unforced capacity for the 2026/2027 and 2027/2028 Delivery Years.[4] PJM acknowledges that its existing market rules otherwise would allow clearing prices to clear at up to $500/MW-day.[5]

The PJM Price Cap Proposal counter-intuitively was made just months after the PJM Board publicly acknowledged a potential capacity shortage facing PJM as imminently as the 2026/2027 Delivery Year, which the Board noted was occurring in part due to the "[r]etirement of thermal generators at a rapid pace due to policy and economic pressures."[6] In that same communication, the PJM Board indicated that one of the two key solutions to alleviating the near-term capacity shortfall risk could be achieved by making "sure price signals accurately reflect current supply-demand fundamentals."[7]

Yet, PJM, disappointingly bowing under the weight of state-imposed political pressure rather than standing up to protect market integrity and reliability,[8]

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[4] *Id*. at 1.

[5] *Id*. at 15.

[6] *See* https://www2.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2024/20241209-board-letter-outlining-action-on-capacity-market-adjustments-rri-and-sis.pdf at 1, provided as Attachment A hereto.

[7] *Id*.

[8] The PJM proposal was not made at PJM's independent volition or after a normal stakeholder process but was submitted to resolve a complaint brought by Pennsylvania Governor Josh Shapiro and the Commonwealth of Pennsylvania at the Commission, which the Commission has not granted. *Governor Josh Shapiro and the Commonwealth of Pa. v. PJM Interconnection, L.L.C.*, Complaint of Governor Josh Shapiro and the Commonwealth of Pennsylvania, Docket No. EL25-46-000 (Dec. 30, 2024)("PA Complaint Proceeding").

submitted a proposal that may lead to catastrophic consequences and is at direct odds with the relatively recent statement of its own Board that it is critical that price signals accurately reflect market conditions. That is, instead of respecting the long-established Commission precedent that competitive markets must allow prices to reflect market fundamentals,[9] such that prices should rise in the face of growing demand and tight supply in order to retain and attract needed supply, PJM is proposing to lower its capacity market price cap to artificially suppress market clearing prices starting with the 2026/2027 Delivery Year (the very same Delivery Year in which its Board fears a capacity shortage) and extending into the 2027/2028 Delivery Year.

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[9] *See e.g.*, *PJM Interconnection, LLC*, 184 FERC ¶ 61,055 at P 88 (2023)(recognizing importance of prices that "accurately reflect reliability needs and supply and demand fundamentals"); *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at PP 1-2 (2016)("Order No. 825")(requiring RTO improvements to ensure that prices reflect system conditions and the actual value of providing the service rather than distorting price signals and muting incentives for resource performance); *id.* at P 163 ("Better formed prices help ensure just and reasonable rates"); *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 at PP 34-43 (2016)(finding energy price cap can impair price formation because inefficient price signals can harm reliability and can inhibit performance and investment), *order on reh'g and clarification* 161 FERC ¶ 61,156 (2017); *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 844, 163 FERC ¶ 61,041 at P 3 (2018)(finding RTO practices that mask system conditions impede market participants' ability to value resources or evaluate the need for new investment and are unjust and unreasonable); *Wholesale Competition in Regions with Organized Electric Markets*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 at P 16 (2008)("Order No. 719")("A well-functioning competitive wholesale electric energy market should reflect current supply and demand conditions."), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059 (2009), *order denying reh'g and providing clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,123 at P 45 (2020)("A well-functioning reserve market should accurately represent the true demand for reserves and produce prices reflective of the marginal cost of meeting that demand."). *See also infra* n.61.

PJM makes this counter-intuitive proposal not because of any conclusion that its existing market rules are unjust and unreasonable. Instead, PJM explicitly states in its filing that "[t]he capacity market remains just and reasonable and is operating as designed, even absent the changes proposed in this filing."[10] Rather, PJM submitted the filing in order to resolve the contested PA Complaint Proceeding,[11] despite that the Commission has not determined the complaint has any merit. PJM indicates that certain state policymakers find unpalatable the possibility that prices may reach the existing price cap in upcoming auctions.[12] These state policymakers should not be given the latitude to undermine the market design that the Commission and courts have endorsed in order to achieve their short-sighted desire to "game" capacity market prices.[13]

[10] PJM Price Cap Proposal, Transmittal Letter at 8, citing Affidavit of Mr. Frederick S. Bresler III, Att. C at P 10 ("Bresler Affidavit").

[11] *See* Protest of PJM Power Providers Group on the Complaint filed by Governor Josh Shapiro and the Commonwealth of Pennsylvania, Docket No. EL25-46 (filed Jan. 27, 2025); Protest of Constellation Energy Generation, LLC to the Complaints of the Joint Consumer Advocates and Governor Josh Shapiro and the *Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C.*, Docket No. EL25-18, *et al.* (filed Jan. 21, 2025); Protest of the Electric Power Supply Association, Docket No. EL25-46 (filed Jan. 21, 2025) ("Protests to PA Complaint Proceeding").

[12] PJM Price Cap Proposal, Transmittal Letter at 2.

[13] If market participants withheld capacity in order to achieve higher prices, a market power investigation surely would ensue. States should not be held to a different standard when seeking to achieve artificially low prices by being sent the message that all that is needed is to bring a complaint to circumvent the market design. For the reasons set forth in the Protests to PA Complaint Proceeding, the Commission should act on the merits to reject that complaint.

While capacity markets such as PJM's are designed to produce revenues that approximate the net Cost of New Entry ("CONE") over time,[14] and the opportunity to recover costs is the engine that keeps needed resources in operation and encourages new construction when needed, certain constituencies take the myopic view that achieving low clearing prices is a paramount consideration, regardless of whether prices clear well below the levels needed to retain existing and attract new investment where and when needed. PJM's proposal cedes to those constituencies and would undermine its capacity market design by impeding the ability of prices to reflect scarcity conditions when they exist and to average out at net CONE over time. This jeopardizes reliability and resource adequacy and will lead to unjust, unreasonable and unduly discriminatory market outcomes.[15]

The PJM Section 205 filing to impose a price cap asks the Commission to ignore a "legion"[16] of past precedent in order to indulge PJM in its game of reliability Russian roulette. The Commission should not countenance this dangerous and ill-conceived gambit. Because the PJM Price Cap Proposal departs from both the

[14] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,035 at P 157 (2020)(finding that, consistent with "a legion of prior Commission orders", in order to "retain sufficient capacity and maintain reliability requirements," "prices need to average out over time to the cost of new entry.") (citing *ISO New England Inc*., 158 FERC ¶ 61,138, at P 52 (2017); *N.Y. Indep. Sys. Operator, Inc.,* 144 FERC ¶ 61,126, at P 26 (2013); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 91 (2006).). *See also ISO New England Inc.*, 158 FERC ¶ 61,138 at P 52 ("[T]he purpose of the [Forward Capacity Market ("FCM")] is to enable [the RTO] to procure sufficient capacity to ensure reliability.... [T]o do so, the FCM will need to clear, on average, over time, at or near Net CONE.").

[15] As the courts have explained "[t]he reasonableness of a rate is assessed in light of the FPA's goals of promoting reliable service at reasonable rates and developing plentiful energy supplies." *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1035 (D.C. Cir. 2022).

[16] *Calpine Corp. v. PJM Interconnection, L.L.C.*,171 FERC ¶ 61,035 at P 157.

Commission precedent cited above and ample court precedents,[17] and especially since it comes at a time when additional resource retirements due to insufficient compensation opportunities cannot be tolerated, the proposal is unequivocally unjust, unreasonable and unduly discriminatory. America's Power[18] therefore protests the PJM Price Cap Proposal in accordance with Rule 211[19] and urges the Commission to reject it as unjust, unreasonable and unduly discriminatory without undue delay.

I. SUMMARY OF REASONS THE COMMISSION SHOULD REJECT THE PJM PRICE PROPOSAL

The Commission should act swiftly to reject the unjust, unreasonable and unduly discriminatory PJM Price Cap Proposal. If implemented, the proposal would jeopardize reliability and resource adequacy, wreak havoc on investor confidence, create uncertainty for projects in the queue, and unduly discriminatorily shift costs from customers in some states and of some types to others.[20]

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[17] The courts repeatedly have confirmed the importance of proper price formation. *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005)(market design cannot be considered flawed for sending prices when supply is scarce and indicated that "[i]f prices are suppressed in a competitive market, a natural inference is that suppliers who could otherwise profitably enter will be deterred from entry"); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 269, 136 S. Ct. 760, 769, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016) ("[a]s in any market, when wholesale buyers' demand for electricity increases, the price they must pay rises correspondingly"); *Town of Norwood, Mass. v. FERC*, 962 F.2d 20, 24 (D.C. Cir. 1992)("some degree of volatility is necessary if prices are to signal the market accurately").

[18] America's Power is a national trade organization that advocates on behalf of the U.S. coal fleet and its supply chain. Its members include generating facilities in PJM that will be adversely impacted if the PJM Price Cap Proposal is implemented.

[19] 18 C.F.R. § 385.211.

[20] The Commission factors investor confidence in its decisions to approve pricing proposals. *See, e.g.*, *Calpine Corp. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,035 at P 141

Reliability and resource adequacy would be jeopardized to the extent urgently needed existing generating units that are economic at the cap existing under the current market rules become uneconomic at the 65% reduction in clearing prices caused by the new price cap. Even if PJM does not clear enough capacity, it has stated it would fail to clear any resource that offered above $325/MW-day, setting the entire market on a catastrophic course.

There is no evidence that the $325/MW-day proposed cap will be sufficient to retain generation with needed attributes, and there is evidence it will not. We present herein historical information about the levels of economic support needed by generators that have supplied service to PJM via Reliability Must Run ("RMR") Agreements, which shows that these resources have needed payments higher than $325/MW-day to avoid retirement. There is no evidence that current generators in today's high cost environment would require lower cost support to remain operational. Artificially forcing capacity market prices lower will lead to the

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("Maintaining the integrity of the market supports investor confidence, which in turn ensures investment in resources to meet future reliability needs."); *ISO New England Inc.*, 162 FERC ¶ 61,205 at P 21 (2018)(capacity market constructs must "produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates. Where participation of resources receiving out-of-market state revenues undermines those principles, it is our duty under the FPA to take actions necessary to assure just and reasonable rates."), *order on reh'g*, 173 FERC ¶ 61,161 (2020); *see id*. at P 24 ("Erosion of investor confidence can prevent the FCM from attracting investment in new and existing non-state-supported resources when investment is needed . . . " and "[i]t is . . . imperative that . . . a market construct include rules that appropriately manage the impact of out-of-market state support, to ensure that the market's underlying principles are met and that the resulting rates are just and reasonable."); *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 at P 36 (2012) (approving PJM pricing proposal for demand resources on the basis that "the improved transparency and price predictability that will result . . . will increase investor confidence in market outcomes"), *reh'g denied*, 141 FERC ¶ 61,096 (2012).

cascading need for new, expensive RMR Agreements. The Commission consistently has wanted RMR Agreements to be relied on as a last-resort when there is no other alternative to keep the lights on, and favors relying on competitive markets to support needed generation.

It is exceedingly risky to invite increased reliance on RMR Agreements. Such agreements are currently only available when transmission constraints exist and are not offered to maintain resource adequacy. To preserve resource adequacy in the face of PJM's dangerous proposal, that will have to change. But even so, the RMR construct does not force units to continue operating, and those that lose confidence in the markets may be unwilling to do so. In addition, RMR Agreements can be expensive, as they cover a return of and on the unit's investment, additional investment the unit needs to continue operating during the agreement's term, as well as transmission upgrades that may be needed for power deliveries from the unit to continue into the future. Any alleged "savings" from the Price Cap Proposal may vanish in the face of these RMR costs, especially when combined with the increased energy costs and lost load costs the proposal invites but that PJM has ignored.

Moreover, the proposal will cause unduly discriminatory cost shifts because the costs of RMR Agreements are allocated differently than capacity costs. As will be discussed further herein, to the extent the PJM Price Cap Proposal is implemented and prompts the need for additional RMR Agreements, customers in Ohio, Illinois and Indiana, where accelerated retirements are at more immediate risk of occurring, would unduly discriminatorily be forced to pay increased costs because of Pennsylvania's policy preference.

The "savings" associated with the Price Cap Proposal are not only illusory because PJM has not accounted for the increased costs of RMR Agreements. It also has not presented analysis of the impact on energy prices given that coal-fired generation that is marginal is at high risk of accelerated retirement, and coal generators with months' worth of on-site fuel have a stabilizing impact on energy prices. As will be shown herein, during this year's polar vortex, the average coal price in PJM was $2.50/MMBtu, whereas natural gas prices were subject to substantial variability, increasing from less than $2/MMBtu in November to almost $30/MMBtu in January when the weather event peaked. Coal-fired generation greatly tempered the level of power prices as without coal the $225/MWh peak prices during the event could have ranged between $400/MWh and $650/MWh, potentially adding $500 million to $1.4 billion in extra costs for consumers due to this single event. And then there is the cost of power outages that the proposal makes that much more likely. Besides the very real potential for loss of life during outages that can't be quantified in dollars, the Department of Energy ("DOE") has estimated that power outages cost America's businesses around $150 billion per year.[21]

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[21] https://www.energy.gov/ne/articles/department-energy-report-explores-us-advanced-small-modular-reactors-boost-grid#:~:text=The%20U.S.%20Department%20of%20Energy%20estimates%20power%20outages%20are%20costing%20American%20businesses%20around%20%24150%20billion%20per%20year. Given load growth since the time of the DOE's estimate, the actual cost of outages is likely higher.

PJM's proposal to appease Governor Shapiro may superficially sound attractive as a way to help consumers during tumultuous economic times, but that is merely its aura, not its reality. Costs will be shifted from the capacity market elsewhere, via RMR Agreements, energy market price spikes and/or lost load events with the resulting costs paid by different customers but still incurred. The Commission has committed to competitive market outcomes as leading to just and reasonable results, and should continue that commitment by rejecting the PJM Price Cap Proposal. The Commission surely does not want the unpalatable reliability and resource adequacy consequences that this proposal's implementation invites to occur on its watch.

II. THE PJM PRICE CAP PROPOSAL

Despite *inter alia*

(a) recognizing a "significant tightening of supply and demand in the capacity market,"[22]

(b) noting that it is "keenly aware of the need for the market to establish proper incentives" for needed investment and that "clearly" now is the time such investment is needed,[23]

(c) recognizing the unfortunate outcome of declining capacity and "retirements of generators with attributes needed to maintain reliability,"[24]

(d) acknowledging that the design basis of the Reliability Pricing Model ("RPM") capacity market calls for elevated prices in response to capacity shortages,[25] and

[22] PJM Price Cap Proposal, Transmittal Letter at 2.

[23] *Id*. at 5.

[24] *Id*. at 8.

[25] *Id*. at 5-6.

(e) asserting that "[i]nvestor confidence is predicated on . . . their belief that the market will accurately reflect [market] fundamentals"[26] and market rule changes "can diminish investor confidence,"[27]

in the PJM Price Cap Filing, PJM proposes to lower the price point at which the capacity market might clear for the next two Delivery Years from about $500/MW-day to $325/MW-day in order to resolve the PA Complaint Proceeding.[28] Regardless of whether the auction clears less capacity than is needed in one or both of those Delivery Years, PJM (shockingly) explained in its filing that a Sell offer above the price cap would not clear the auction under its proposal.[29]

PJM expressed concerns that the PA Complaint Proceeding, and its requested refund effective date, were causing damaging market uncertainty, claiming that resolving that uncertainty would be beneficial.[30] While PJM in several passages of its filing acknowledged the importance of retaining *existing* generation,[31] its filing

[26] *Id*. at 11, 16.

[27] *Id*. at 16.

[28] Notably, the $500/MW-day price ceiling already reflects a reduction from the level of clearing prices that would have been possible in the 2026/2027 Delivery Year. The $500/MW-day outcome was the result of a recent Commission order allowing the use of a combustion turbine as the Reference Resource through 2027/2028 Delivery Year. *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,088, at P 66 (2025); *PJM Price Cap Proposal* at 11, and n.30 (citing *Id*. at 27, citing Bresler Affidavit at P 16). That change is estimated to have reduced the maximum clearing prices by about 30%.

[29] PJM Price Cap Proposal, Transmittal Letter at 19. It is unclear how any such capacity shortfall would be filled, which is another reason PJM's proposal is unjust and must be rejected.

[30] *Id*. at 3, 33. The uncertainty could be resolved without the damaging impact on market confidence of price suppression tactics by prompt Commission action to reject the PA Complaint Proceeding.

[31] *Id*. at 16.

primarily was focused on the impact on *new* generation,[32] indicating that the short period between the auction and the Delivery Year diminished but did not extinguish the ability of new generation to respond to the price signals.[33]

PJM touted the fact that it proposed a price floor to accompany its price cap, claiming the existence of the price floor will discourage resources from exiting the market, and is likely to encourage Capacity Market Sellers to continue to reverse decisions to deactivate resources or forestall such decisions.[34] However, at the same time, PJM admitted that the floor was meaningless as a practical matter because there would need to be a "dramatic" and "unfounded" expectation of an increase of 100,000 MW of capacity supply before clearing prices would be impacted by its proposed floor.[35]

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[32] *Id*. at 15.

[33] *Id*. at 12, 24. The fact that auctions are not occurring three years forward but on a more compressed schedule is not a reason to mute the capacity market price signal. Existing capacity can respond by deferring retirement decisions and a portion of capacity in the queue can respond by accelerating their projects in response the price signal a prompt auction sends. Various other RTOs have or are planning to introduce prompt auctions that will still signal the need to retain existing and attract new investment. *See* https://www.iso-ne.com/static-assets/documents/100021/a03_mc_2025_03-11-12_prompt_iso_presentation.pdf , at 51-53, 41-50.

[34] PJM Price Cap Proposal at 25.

[35] *Id*. at 27, citing Bresler Affidavit at P 16.

III. RELIABILITY RISKS AND DISPATCHABLE GENERATION DEACTIVATION IN PJM

A. NERC is Already Concerned about the Risk of "Alarming Unreliability" Even Without Considering the Impact of the Price Cap Proposal.

In its 2024 Long-Term Reliability Assessment, the North American Electric Reliability Corporation ("NERC") recognized the increasing risk to reliability and resource adequacy in PJM, indicating that "[r]esource additions are not keeping up with generator retirements and demand growth."[36] In fact, NERC recommended that utilities reconsider their retirement plans. It noted that "[a]ccelerated retirements of existing coal, natural gas and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the [Bulk Power System] in the next 10 years."[37] NERC indicated that "[t]he lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable."[38] As to the PJM region in particular, in which it noted PJM has indicated the potential for over 32 gigawatts (GW) of deactivations through 2034, NERC explained that:

> Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation

[36] NERC, 2024 Long-Term Reliability Assessment (Dec. 2024) ("2024 LRTA"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[37] *Id*. at 19

[38] *Id*.

technologies, available at different times, are required to replace a megawatt of thermal generating capacity.[39]

PJM has recognized as much, having recently posted its effective load carrying capability ("ELCC") metrics for the 2026/2027 BRA in which dispatchable resources were assigned high ELCC values (*i.e.* 83% for coal) while intermittent resources like fixed-tilt solar achieved an ELCC metric of only 8%.[40]

NERC previously highlighted the reliability risks associated with accelerated thermal retirements in its 2023 Long-Term Reliability Assessment, in which it remarked that "PJM [has] found increasing reliability risks due to the potential for the timing of generator retirements to be misaligned with load growth and the arrival of new generation on the system," and noted that "[t]rends toward higher demand, faster generator retirements, and slower resource entry could expose PJM to decreasing Planning Reserve Margins and reliability challenges from imbalanced resource composition and resource performance characteristics."[41]

B. PJM Admits that Generators with Needed Reliability Attributes Were Retiring Even Without the Signal its Price Cap Proposal Will Send.

Despite the threats to PJM reliability associated with excessive retirements of existing thermal generation sources recognized by NERC, PJM reports currently

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[39] *Id.* at 93.

[40] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf.

[41] NERC, 2023 Long-Term Reliability Assessment, at 76 (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

pending deactivation requests of over 5,000 megawatts (MW),[42] on top of the over 1,100 MW actually deactivated during 2024 and to date in 2025.[43] While these retirements may have been spurred by a variety of reasons, the failure of the PJM market to provide sufficient compensation to warrant ongoing operations and additional investment required to sustain existing power plants has been cited as a reason for various of these deactivation requests.[44]

Confirming the importance of ameliorating – rather than worsening - economic considerations to maintaining the generation fleet in operation, the Independent Market Monitor's State of the Market Report for the Third Quarter of 2024 indicated that of the 53,379 MW of mostly thermal units at risk of retirement in PJM through 2030, only 19,635 MW were at risk due to regulatory reasons, whereas 33,744 MW were at risk due to economics.[45] The PJM Board letter provided in Attachment A and discussed previously also recognizes the impact of economic

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[42] *See* https://www.pjm.com/planning/service-requests/gen-deactivations (future deactivations tab).

[43] *See* https://www.pjm.com/planning/service-requests/gen-deactivations (deactivated generators tab).

[44] For example, NRG's Indian River cited continuing expected uneconomic operations after experiencing two consecutive years of cash losses as the reason for its retirement decision in its filing for an RMR Agreement. *See NRG Power Marketing LLC*, Docket No. ER22-1539 at 5 (filed Apr. 1, 2022). PJM's generation deactivations data shows that Indian River Unit 4 ultimately deactivated on February 24, 2025. Talen Energy Corporation's Brandon Shores and H.A. Wagner generating facilities similarly explained that continued plant operations were no longer economically feasible in their RMR Agreement filing. *Brandon Shores LLC*, RMR Arrangement – Continuing Operations Rate Schedule, Docket No. ER24-1790 at 2 (filed Apr. 18, 2024)("Brandon Shores RMR Filing").

[45] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q3-som-pjm.pdf at 206.

pressures in spurring retirements and concludes that accurate price signals are needed to stem the tide of retirements of needed resources.[46] And in the PJM Price Cap Proposal, PJM recognized declining capacity has occurred for reasons including "retirements of generators with attributes *needed* to maintain reliability."[47]

C. Dispatchable Coal Generation, Which is Put at Risk by the PJM Price Cap Proposal, Reduces Energy Price Volatility and Has Been Instrumental in Keeping the Lights On.

A recent report prepared by Energy Ventures Analysis on behalf of America's Power, entitled *Operation of the U.S. Power Grid During the January 2025 Polar Vortex,* analyzed the performance of resources in PJM (and other RTOs) during the January 2025 Polar Vortex ("EVA Polar Vortex Report").[48] As indicated in that report and in the Affidavit of Seth Schwartz provided as Attachment C hereto, a new record for PJM electricity demand of 132 GW was set in the PJM region during this event.[49] On average, nearly one-quarter of this total was met by coal-fired generation, and over 70% was met by fossil fuel generation over the course of the event.[50] On the peak day (January 22), coal-fired generation provided 43% of the additional electricity that was needed to keep homes and businesses warm. The report demonstrated that the dispatch of coal-fired generation in PJM during the January 2025 Polar Vortex limited

[46] Attachment A at 1.

[47] PJM Price Cap Proposal at 8 (emphasis added).

[48] Available at https://americaspower.org/issue/operation-of-the-u-s-power-grid-during-the-january-2025-polar-vortex/ and provided as Attachment B.

[49] *Id.* at 19; Attachment C at P 2.

[50] Attachment B at 20; Attachment C at P 3.

the volatility of power prices that otherwise would have been more greatly affected by the wide swings in natural gas prices. The average coal price was $2.50/MMBtu, whereas natural gas prices were subject to substantial variability, increasing from less than $2/MMBtu in November to almost $30/MMBtu when the weather event peaked.[51]

The report further indicates that coal-fired generation greatly tempered the level of power prices. Without coal, the $225/MWh peak prices during the event could have ranged between $400/MWh and $650/MWh, potentially adding $500 million to $1.4 billion in extra costs for consumers.[52] The report, which was released before the PJM Price Cap Proposal existed and thus did not consider the additional retirements it would spawn, states that "alarmingly, about one-third of the existing coal fleet is announced to retire before the end of the decade. As this extreme weather event and the others before it have shown, dispatchable, highly reliable generating resources like coal-fired power plants are paramount to ensuring reliable and affordable electricity service to electric consumers across the United States."[53] The PJM Price Cap Proposal should be expected to accelerate rather than delay these retirements. This Polar Vortex example demonstrates both the illusory nature of the "cost savings" PJM suggests its Price Cap Filing will achieve, as well as the risk to

[51] Attachment B at 2, 30; Attachment C at P 4.

[52] Attachment B at 2, 31; Attachment C at P 5.

[53] Attachment B at 31; *see also* Attachment C at P 6.

reliable service that would be associated with any proposal that accelerates retirements of resources with attributes that PJM needs for reliability.

D. PJM Has Relied on RMR Agreements, Often Involving Coal Plants, as a Last Resort to Preserve Reliability.

In the face of this rash of deactivation requests from needed generators,[54] and PJM determinations of reliability need for the generators seeking to deactivate,[55] the Commission has approved various RMR arrangements providing cost-based compensation.[56] The Commission has confirmed that such needed generators may recover their full cost of service, including a return of and on their investments, and has approved the recovery of fixed costs, variable operations and maintenance costs and the costs of project investment needed to allow continued reliability operations

[54] While called deactivation requests, these are not requests for permission because PJM does not have the ability to deny a generator the right to deactivate. See https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20231205/20231205-item-03---generation-deactivation-notification-update.pdf at 1 ("PJM does not approve deactivations, but rather identifies whether the requested deactiva tion date could lead to reliability concerns on the system. When PJM determines a proposed deactivation would adversely affect the reliability of the Transmission System due to upgrade completion timeline and absent operational measures, PJM desires and requests the Generation Owner extend operations of the deactivating unit(s). The Generation Owner may elect to support system reliability by operating until necessary network upgrades are completed by either filing its proposed Cost of Service Recovery Rate (CSRR) at FERC or accepting the Deactivation Avoidable Cost Credit (DACC) provided in the Tariff.")

[55] *H.A. Wagner LLC & Brandon Shores LLC*, 187 FERC ¶ 61,176 at P 29 ("PJM states that the Brandon Shores and Wagner generation facilities are needed for reliability until the required transmission upgrades are in place, expected by December 31, 2028 (at the earliest).").

[56] *NRG Business Marketing LLC, et al.*, 190 FERC ¶ 61,026 at PP 32, 37 (2025); *Brandon Shores LLC*, Joint Offer of Settlement re: Continuing Operations Rate Schedule, Docket No. ER24-1790-001 (filed Jan. 27, 2025).

throughout the term of the RMR agreements.[57] Costs incurred to compensate generators that are parties to RMR Agreements are allocated to the load in the zone of the transmission owner responsible for the transmission upgrades that would obviate the need for the RMR generator in accordance with Part V of Section 119 of the PJM Open Access Transmission Tariff.[58] This allocation method differs from the allocation of capacity costs.

IV. PROTEST

A. PJM's Proposal is Unjust and Unreasonable Because it Undermines the Capacity Market Design and Will Accelerate the Retirement or Need for RMR Status of Otherwise Economic Units, Particularly Needed Dispatchable Generation Units.

1. The Price Cap Proposal Undermines the RPM Market Design.

PJM itself states in the PJM Price Cap Proposal that "[a] key tenet of the market design is that clearing prices signal the relative need for new entry or for uneconomic resources to exit the market"[59] and that its RPM capacity market was designed to respond to capacity shortages through elevated prices.[60] These admissions are

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[57] 190 FERC ¶ 61,026 at PP 6-7, 33 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112, at P 40 (2004) ("[RMR] units need to be compensated at a level that adequately covers their fixed and variable costs."); *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116, at P 17 (2015) ("Compensation to an RMR generator must at a minimum allow for the recovery of the generator's going-forward costs, with parties having the flexibility to negotiate a cost-based rate up to the generator's full cost of service.") (internal citations omitted) (citing *Ameren Energy Res. Generating Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, at P 84 (2014) (finding it unjust and unreasonable to not allow [System Support Resources] to receive compensation for the fixed costs of existing plant)).

[58] https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/destf/2023/20231109/20231109-item-02---rate-mechanisms-and-cost-allocation-of-rmr-units.pdf.

[59] PJM Price Cap Proposal at 23.

[60] *Id.* at 10, Bresler Affidavit at PP 5-6.

consistent with a long line of Commission precedents that have required markets to allow prices to reflect the value of lost load during scarcity conditions.[61] The courts have agreed, in confirming the importance of proper price formation. For example, in *Edison Mission Energy, Inc. v. FERC*,[62] the D.C. Circuit held that a market design cannot be considered flawed for sending prices when supply is scarce and indicated

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[61] *See, e.g.*, *PJM Interconnection, L.L.C.*, 180 FERC ¶ 61,135 at P 33 (2022) (explaining that properly implemented scarcity and shortage pricing is efficient and provides compensation for the value resources are providing); *PJM Interconnection, L.L.C.*, 173 FERC at P 67 (stating that "the Commission has required the RTOs to implement scarcity pricing, finding that RTO market designs were unjust and unreasonable if energy prices failed to reflect shortages in reserves"); Order No. 719, 125 FERC at P 192 (finding that rules "that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory"); *id.* rules that do not allow prices to rise during a shortage "may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation"); Order No. 825, 155 FERC at PP 1-2 (requiring shortage pricing in energy and operating reserves markets to reflect value of the service and noting that a failure to properly price a service results in a "distort[ion] [of] price signals and [a] fail[ure] to provide appropriate signals for resources to respond to the actual operating needs of the market"); *id.* at P 163 (finding "that the shortage pricing requirement will help ensure that prices rise sufficiently and appropriately to allow supply to meet demand during an operating reserve shortage, and thus will more accurately reflect the value a resource provides"). Similarly, the Commission has held that prices should rise when supply is tight relative to demand to encourage reduced usage and prompt new investment. *Midwest Independent Transmission System Operator, Inc.,* 102 FERC ¶ 61,280 at P 47 (2003). In its seminal Order No. 2000, the Commission determined that accurate price signals are the link between current usage and future expansion. *Reg'l Transmission Orgs.*, Order No. 2000, *FERC Statutes and Regulations* ¶ 31,089 at 32,165 (1999) (cross-referenced at 89 FERC ¶ 61,285), *order on reh'g*, Order No. 2000-A, *FERC Statutes and Regulations* ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cty. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001). Further, the Commission clearly has stated "the first principles of capacity markets are that "[a] capacity market should facilitate robust competition for capacity supply obligations, provide price signals that guide the orderly entry and exit of capacity resources, result in the selection of the least-cost set of resources that possess the attributes sought by the markets, provide price transparency . . . ." *ISO New England Inc.*, 162 FERC ¶ 61,205 at P 21; *see also ISO New England Inc.*, 158 FERC ¶ 61,138 at P 9 (2017)("One purpose of capacity markets is to send appropriate price signals regarding where and when new resources are needed."), *aff'd sub nom.*, *NextEra Energy Res., LLC v. FERC*, 898 F.3d 14 (D.C. Cir. 2018). *See also* supra n.9.

[62] 394 F.3d 964, 969 (D.C. Cir. 2005.

that "[i]f prices are suppressed in a competitive market, a natural inference is that suppliers who could otherwise profitably enter will be deterred from entry."[63] The Supreme Court of the United States similarly has recognized that "[a]s in any market, when wholesale buyers' demand for electricity increases, the price they must pay rises correspondingly."[64]

PJM notes that its own expert witnesses at the Brattle Group foresee a strong possibility that prices may clear at the cap for multiple years.[65] PJM recognizes that the increases in demand through load growth are "not an anomaly but mark the beginning of a trend of increased load growth across PJM."[66] And PJM acknowledges that "high prices at the cap are consistent with the marginal value of capacity when the region is short and needs new investment."[67] Finally, not only is *new* investment needed, but *existing* generators must remain in operation if capacity requirements are to be met in upcoming RPM capacity auctions. Notwithstanding the combination of these express recognitions, PJM unreasonably seeks to block prices from approximating the marginal value of capacity to signal the need to retain and expand capacity supply.

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[63] *Id.*

[64] *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 269, 136 S. Ct. 760, 769, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016).

[65] PJM Price Cap Proposal at 11.

[66] *Id.* at 10, citing *PJM Interconnection, L.L.C.*, Revisions to Reliability Pricing Model of PJM Interconnection, L.L.C., Docket No. ER25-682-000, Attachment D (Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection, L.L.C.) ¶ 50 (Dec. 9, 2024) ("Dec. 9 Graf & Marzewski Aff.").

[67] PJM Price Cap Proposal at 23.

Here, despite all of these precedents, and even despite its own recognition of how markets are supposed to react in times of supply-demand imbalance, PJM seeks to impede prices from reflecting scarcity conditions in order to satisfy Josh Shapiro, the Governor of Pennsylvania. While PJM seeks to take credit for its past efforts to improve the ability of markets to reflect "true supply-demand fundamentals," and acknowledges that "rule changes can diminish investor confidence,"[68] PJM concedes that its proposed cap is not aimed at protecting the markets, encouraging the retention of existing and addition of new supply resources, or preserving reliability, but "is intended to protect consumers."[69] As discussed in the next section, PJM is wrong in believing that customers are protected by its tinkering with market fundamentals.

PJM's proposal undermines market fundamentals because at the precise time when it is in desperate need of capacity, the proposal will make units that would have been economic, uneconomic.[70] Its proposal sends the wrong price signal and will have real and harmful consequences. Under the current market rules, a unit may be economic and receive a signal to remain operational if it submits a Sell Offer and prices clear at up to about $500/MW-day. Under the Proposed Price Cap Filing, a unit would be rendered uneconomic at $325/MW-day, and at a sell offer above that level

[68] *Id*. at 16

[69] *Id*. at 22.

[70] As noted previously, in the Third Quarter PJM State of the Market Report, the IMM reported that the majority of capacity in PJM is at risk of losing is planning to retire due to economic considerations. This proposal will only worsen those considerations, which may accelerate those retirements and prompt others. *See* discussion at Section III B *supra*.

would not clear the capacity auction, regardless of whether the auction cleared insufficient resources.[71] The resource that did not clear would receive a message that it is not needed even in the face of insufficient resources ***by design***. Such an outcome would be truly remarkable, and not in a good way, as an avoidable capacity shortage that is surely not just and reasonable would be created.

The $325/MW-day price cap proposed by PJM is arbitrary and PJM has not demonstrated that it is just and reasonable. In fact, it is substantially too low to retain existing needed generation. In its State of the Market Report for January through September of 2024,[72] the PJM IMM compiled data showing the actual costs paid to RMR generators that selected cost-of-service recovery in PJM pursuant to RMR contracts that have concluded. The chart below excerpts from the information compiled by the IMM and demonstrates that while a clearing price of $500/MW-day would have rendered more than half of these generators' continued operation economic, a clearing price capped at $325/MW-day would have rendered every one of them uneconomic so as to require an RMR contract to avoid their deactivation. PJM has provided no evidence in support of its filing to demonstrate that generators facing deactivation decisions today face lower costs than this sample of generators that have provided RMR service to PJM under cost-of-service rates. This thus shows

[71] PJM Price Cap Proposal at 19.

[72] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q3-som-pjm.pdf (Nov. 14, 2024) at 355.

the high likelihood of inadequacy of the newly proposed $325/MWh-day price cap to retain existing generation.

Unit	**Fuel**	**ICAP**	**Docket No.**	**Actual Cost ($/MW-day)**
Indian River 4	Coal	410	ER22-1539	$537.03
BL England 2	Coal	146	ER17-1083	$472.88
Elrama 4 & Niles 1	Coal	279	ER12-1901	$363.17
Cromby 2	Oil	201	ER10-1418	$407.80
Eddystone 2	Coal	279	ER10-1418	$754.81

The Commission will be forced to approve RMR agreements for generators needed for reliability but that are uneconomic at the new, lower PJM price cap. While the Commission has stated that each new RMR Agreement takes a generator out of the market that could otherwise set the market clearing price, putting pressure on the next marginal generator, and potentially leading to the cascading need for RMR Agreements, and expects for RMR agreements to be a last resort,[73] not an integral

[73] *See New York Independent System Operator, Inc.*, 155 FERC ¶ 61,076 at P 33 (2016)(Commission stating that "[w]e not only want to ensure that RMR agreements are limited in duration, but that they are only entered into in the first place as a last-resort measure."); *New York Independent System Operator, Inc*., 150 FERC ¶ 61,116 at P 11 (2015) ("RMR filings should be made only to temporarily address the need to retain certain generation until more permanent solutions are in place and that all alternatives should be considered to ensure that designating a generator for RMR service is a last resort option for meeting immediate reliability needs"); *Norwalk Power, LLC*, 120 FERC ¶ 61,048 at P 2 (2007)(reiterating RMR agreements are to be utilized as a last resort)(*citing Berkshire Power Co., LLC*, 112 FERC ¶ 61,253 at P 22 (2005)(stating that "an RMR agreement should be viewed as a tool of last resort for a generator"); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 40 (2005)(noting that "[t]he Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation); *Devon Power LLC*, 103 FERC ¶ 61,082 at P 31 (2003)(finding "that RMR agreements should be a last resort)); *Bridgeport Energy, LLC*,

part of the market design without which reliability would be at risk, RMR agreements would become an integral part of the market design. PJM has not shown that its system will not need to rely on an increasing number of stop-gap RMR agreements at costs that may eliminate any illusory "savings" associated with interfering with the market clearing mechanism by imposing a cap.

2. The Expectation of Lower Consumer Costs From the Price Cap Proposal is Illusory.

PJM is wrong in thinking that consumers can be protected at the expense of reliability and resource adequacy. Consumers expect reliable electricity supply and suffer greatly when power outages occur. PJM has not demonstrated that artificially suppressed capacity market clearing prices benefit consumers. Nor, as discussed more fully *infra*, has PJM factored into its claims the increase in the costs consumers will bear for RMR Agreements and related transmission upgrades, increased energy costs and increased loss of load costs that will make its savings illusory and lead to unduly discriminatory cost-shifting. PJM also has given short shrift to the impact that the loss of investor confidence in the PJM market will have. The loss of confidence should be expected to encourage investors to make their infrastructure investments in more stable markets instead of PJM.[74]

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112 FERC ¶ 61,077 at P 31 (2005)("an RMR contract is a tool of last resort" that may be "contrary to the intent of the competitive marketplace").

[74] The words of the Independent Market Monitor for PJM, uttered many years ago, are eerily on point as to the impact of price suppression events:

> RPM is intended to provide price signals that incent entry when it is needed. If investors believe that once they have committed to an investment, market buyers can act to systematically suppress prices in future years, the result would be to significantly undermine their confidence that they can achieve

Any alleged "savings" from reducing the capacity clearing price due to the imposition of the cap is speculative because, as the need for RMR agreements increases, the cost-of-service payments made to those RMR generators will increase. The Commission has recognized that RMR units are entitled to recover a return of and on their existing investments, as well as new investments they must make to continue RMR operations during the term in which they are needed. In addition, transmission retrofit costs may be triggered to allow for the continuing operation of RMR units. In the case of the Brandon Shores facility discussed earlier, those costs alone are estimated at $1.5 billion.

Moreover, as the EVA Polar Vortex Report shows,[75] the coal units at increased risk of premature retirement if the Price Cap Proposal is approved have been instrumental in keeping electricity prices stable and keeping the lights on. The findings of the EVA Report bear repeating here: Without coal, the $225/MWh peak prices during this year's Polar Vortex event in could have ranged between $400/MWh and $650/MWh, potentially adding $500 million to $1.4 billion in extra costs for consumers.[76]

> projected returns. Under such circumstances, *no one is likely to build on the basis of market expectations*.

Post Technical Conference Comments of the Independent Market Monitor for PJM, Docket Nos. ER11-2875, et al. at 3 (Aug. 29, 2011)(emphasis added).

[75] *See* Attachment B, Attachment C and discussion at III.C *supra*.

[76] Attachment B at 2, 31; Attachment C at P 5.

3. PJM Cites Precedents that Dictate its Proposal Should be Rejected Rather than Accepted.

In arguing that its proposed interim price caps are consistent with Commission precedent, PJM cites to two cases in which the Commission accepted a price cap in the past, itself acknowledging that the cases did not involve analogous situations.[77] In the *CAISO Order*, the Commission accepted CAISO's proposal to impose a $2,500/MWh price cap and a price floor of negative $2,500/MWh because it was alleged that "unanticipated and unusual circumstances" associated with CAISO's first year of a transition to a redesigned market, which may be caused by software limitations that did not properly consider operating contracts, among other factors, might lead to severe settlement impacts.[78] CAISO asserted that the proposal would not dampen economic price signals because it would not actually impact settlement rates 99% of the time because prices were generally within the range of its proposed cap and floor.[79]

The Commission accepted the proposal to avoid "anomalous prices" noting that there could be "extreme market clearing prices under MRTU that were not anticipated by either the CAISO or its market participants."[80] It specifically recognized the infrequency with which the cap and floor would have any impact

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[77] PJM Price Cap Proposal at 30-33, *citing California Independent System Operator,* 126 FERC ¶ 61,082 (2009)("*CAISO Order*") and *ISO New England, Inc*., 88 FERC ¶ 61,316 (1999)("ISO-NE Order").

[78] *CAISO Order* at P 2, 20-21.

[79] *Id*. at n3.

[80] *Id*. at P 20.

because prices would normally not be outside the range.[81] The Commission explicitly noted the "relatively small" impact on pricing signals, given the expectation the cap and floor would come into play less than 1% of the time, finding that "[i]n these limited circumstances, it is unlikely that the proposed price cap and floor would significantly distort economic incentives.[82]

It is telling that this non-analogous case is one of the only cases PJM cited in support of its claim that its proposal is consistent with Commission precedent. The Commission permitted the CAISO caps and floor to become effective only upon determining that they would not have much of an impact on price signals. There, prices above the proposed cap were expected to be rare. To the contrary, the whole purpose of the PJM Price Cap Proposal is to blunt the economic signal the capacity market is expected to send as prices near or reach the current cap. PJM has stated the floor is largely meaningless because it is exceedingly unlikely clearing prices would clear below the floor in any event, but the ceiling is expected to suppress clearing prices for two Delivery Years. The PJM prices that will occur absent the price suppression associated with the PJM Price Cap Proposal are not unanticipated or unusual but are within the current PJM-endorsed Commission-approved range, which PJM has claimed is *not* unjust and unreasonable. The Commission's CAISO Order accordingly dictates for the rejection of the PJM Price Cap Proposal.

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[81] *Id*. at P 22.

[82] *Id*. at P 24, 32.

In the *ISO-NE Order* that PJM cites, the Commission was convinced that a market design flaw existed in ISO-NE's existing market rules in which market participants were strategically bidding to set the market price during certain emergency conditions, leading to there being "no effective price limit on the bids."[83] The Commission explained that the price cap was not a desirable solution, and that fixing the design flaw would have been optimal, but it reluctantly allowed the price cap in the circumstances presented.[84] In the PJM situation, there is no market flaw. Instead, the market is operating as intended to send a price signal that existing and new supply are needed. The market design is allowing prices to approximate Net CONE over time exactly as designed, whereas actions that lop off the highs whenever they are expected to occur may mathematically preclude the possibility of cost recovery of Net CONE over time. It warrants stating again that PJM has not asserted any design flaw exists but has expressly acknowledged that its existing market rules without the change it has proposed are just and reasonable. Accordingly, the ISO-NE Order does not support PJM's proposal.

4. The Price Cap Proposal is at Odds With PJM's Other Efforts to Increase Capacity Levels.

In its very recent Reliability Resource Initiative ("RRI") filing to the Commission, PJM sought to move large projects with needed reliability attributes forward out-of-order in its generator interconnection queue, acknowledging the

[83] *ISO New England, Inc.*, 88 FERC ¶ 61,216 at 61,971 (1999).

[84] *Id.*

"pressing need to address resource adequacy concerns" to "address PJM's near-term reliability challenge."[85] It blamed the "accelerated premature retirement of generation" on policy preferences, without acknowledging that premature retirements are accelerated by economic considerations.[86] It noted that even if the pace of retirements were to decelerate, exponential load growth is on course to lead to demand that outstrips supply because "load growth and generator retirements are significantly outpacing the entry of new generation" and the intermittent resources that make about 94% of its generator interconnection queue have "different operating characteristics from thermal generation, and provide less Capacity capability."[87] The resources are not dispatchable resources that may be available throughout the day, every day. PJM acknowledged that the decreased supply offered due to a "large number of generator retirements" caused high clearing prices in the BRA for the 2025/26 Delivery Year.[88] In accepting the RRI proposal, the Commission recognized the role premature generator retirements play in leading to the expectation of a resource adequacy shortfall.[89] The concurring Commissioners explicitly noted their concern that RRI may not "prevent the resource adequacy crisis

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[85] *PJM Interconnection, L.L.C.*, Docket No. ER25-712, Tariff Revisions for Resource Reliability Initiative at 1, 4 (filed Dec. 13, 2024).

[86] *Id.* at 2, 13.

[87] *Id.* at 8, 13-14.

[88] *Id.* at 15.

[89] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 at P 14 (2025); *see also id.* Rosner and Phillips, Comm'rs, concurring at P 3 (citing to the role of accelerating resource retirements in putting "PJM in grave danger of not having enough generation to meet demand").

that motivated PJM to develop this proposal in the first place."[90] The Commission cited to PJM's representation that it was "pursuing every avenue to address its near-term resource adequacy issue."[91] Yet in the Price Cap Proposal, contrary to that representation, PJM seeks to worsen the economic climate for generators with needed reliability attributes, therefore counterproductively and unjustly and unreasonably contributing to even more, and more accelerated, premature retirements of these resources. While the RRI is one tool intended to take a step forward to ameliorate the supply shortage conditions in PJM, the PJM Price Cap Proposal harmfully would take PJM several steps backwards. The Commission therefore should resoundingly reject the proposal.

B. PJM's Proposal Should be Rejected Because it is Unduly Discriminatory.

As indicated in the previous discussion, PJM's discussion in the filing focuses primarily on the ability to attract new generation versus to maintain existing generation. Most new generation in the queue is intermittent while much existing retiring generation is thermal, which can provide significant reliability attributes. As the RMR cost data presented in the previous section demonstrates, various generators that PJM has found to be needed for reliability and that have obtained RMR contracts have had actual costs well in excess of the $325/MW-day price cap that PJM seeks to impose. Existing thermal generators will be treated in an unduly

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[90] *Id*. Rosner and Phillips, Comm'rs, concurring at P 12.

[91] *Id*. at P 17.

discriminatory manner as compared to new intermittent generators because PJM has established a cap insufficient for many existing thermal generators to justify continued operations, even though PJM needs capacity from thermal generation given its higher ELCC value. Taking coal units as an example, these rely more heavily on the capacity market revenues to sustain operations because they may be dispatched infrequently in the energy market. In order to make investments to reduce emissions, the fleet needs to obtain compensation sufficient to afford those investments. In order to justify continued operations for reliability and to maintain the health of its supply chain, the coal fleet needs additional, not reduced, compensation. The proposal would have an unduly discriminatory impact on the highly reliable coal fleet contrary to the FPA's requirements.

Moreover, any price cap at a mere $325/MW-day should be expected to prompt the need for additional RMR agreements (although these historically have been negotiated only for reliability reasons rather than to promote resource adequacy). The costs of such RMR Agreements are assigned to customers in the transmission zone in which transmission reliability upgrades are needed. Capacity clearing costs, on the other hand, are allocated more broadly across the PJM footprint if prices among the zones do not separate. Accordingly, to the extent the PJM proposal prompts the need for RMR agreements that would not otherwise be needed, cost shifts may occur as the cost allocation for the RMR contracts and the capacity market clearing costs differs. For the 2025/2026 BRA, the clearing price in the so-called "Rest of RTO" portion of PJM was $269.92/MW-day whereas there was price separation in the Locational Deliverability Areas for Baltimore Gas & Electric and Dominion Energy where capacity cleared at $466.35 and $444.26/MW-day, respectively.

What the difference in cost allocation approaches means as a practical matter is that if units at risk of accelerated retirement, such as the Kincaid units in Illinois (combined capacity of 1,108 MW),[92] the Miami Fort units in Ohio (combined capacity of 1,020 MW),[93] and the Rockport units in Indiana (combined capacity of 2,600 MW),[94] are awarded RMR contracts to avoid retirement because, while they would have been economic at the $500/MW-day price cap in the current market rules, they are uneconomic at the $325/MW-day price cap, but are needed for reliability, ratepayers in the states of Illinois, Ohio and Indiana, respectively, will be left paying for a policy outcome prompted by the Commonwealth of Pennsylvania. Rather than having the costs of this needed capacity spread across the Rest of RTO via the capacity market clearing mechanism, funding the costs of needed generation will be concentrated in the states where the generators PJM can't do without are located. Such a result would be the epitome of unduly discriminatory.

When an RMR contract is avoided by sending the right market signal in the capacity market, not only are the ongoing costs of the generator recovered through

[92] https://www.utilitydive.com/news/vistra-retire-68-gw-coal-blames-irreparably-dysfunctional-miso-market/586113/.

[93] See n92.

[94] https://www.aep.com/search/?q=Rockport#resultsList.

the capacity market rather than through the RMR contract, but the costs of any transmission retrofits PJM determines are required to maintain transmission security when the unit deactivates are also avoided or postponed. By the time the unit that is properly compensated in the capacity market deactivates, replacement generation that eliminates the need for the transmission retrofit may be operational. Markets allow for the orderly entry and exist of generation. RMR is a last resort to be implemented only after markets fail.

C. RMR Market Rule Changes Will be Needed if the PJM Price Cap Proposal is Implemented.

RMR agreements have been permitted historically in PJM to reliably maintain transmission security and not for resource adequacy. In light of the near-term potential for a capacity shortfall, if the PJM Price Cap Proposal is implemented, the reasons RMR agreements can be approved should be expanded to encompass resource adequacy. It is the height of recklessness for PJM to blithely propose that any Supply offers above $325/MW-day will not clear, despite whether PJM is experiencing a capacity shortage. The Commission cannot, consistent with its FPA responsibilities, allow an avoidable capacity shortage to be created by this proposal.

While America's Power urges the Commission to reject the PJM proposal to cap capacity market prices, if a cap will be implemented, it may only be permitted if needed generation has a path to obtain compensation the market is now denying it. Any other result would unjustly and unreasonably imperil resource adequacy. The missing money that the capacity market is supposed to provide needed generators, if blocked by PJM's proposal, needs to come from somewhere. Accordingly, any price cap should be permitted only if the Commission requires a change to the rules for RMR eligibility so that needed existing generators for resource adequacy have a path to obtain full cost-recovery of and on their investment and make the additional investments needed to maintain operations for as long as required.

D. PJM Has Failed to Meet its Section 205 Burden to Show That its Proposal is Just and Reasonable and Not Unduly Discriminatory

Section 205 of the FPA requires that the public utility proposing tariff revisions bear the burden of proof to demonstrate that the changes are just and reasonable and not unduly discriminatory.[95] PJM has not demonstrated that its proposal will not accelerate the retirement of resources with needed reliability attributes or that are needed for resource adequacy. PJM has not considered the cost-shifting its proposal will cause, or the increased energy and RMR costs it should be expected to prompt. The Commission rejects filings where the filing public utility has failed to meet this burden, where, as here, the proposal deviates from precedent and will result in harm to the market. For example, when PJM proposed tariff changes to implement a new Intelligent Reserve Deployment ("IRD") as a replacement to its then current all-call reserve deployment approach,[96] PJM contended that the IRD proposal would better align prices with system conditions and increase reliability.[97] The Commission

[95] 16 U.S.C. § 824d(a)("[a]ll rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy . . . shall be just and reasonable."

[96] *PJM Interconnection, L.L.C.*, 180 FERC ¶ 61,089 at P 6 (2022), *order denying reh'g* 181 FERC ¶ 61,191 (2022).

[97] *Id.* at P 7.

rejected the proposal because PJM failed to show that the IRD was just and reasonable since it could "produce a misalignment between prices and actual system conditions."[98] The Commission in rejecting that filing, highlighted PJM's acknowledgement that "its system w[ould] remain reliable without implementing the IRD proposal."[99] PJM here has made a similar acknowledgement that "[t]he capacity market remains just and reasonable and is operating as designed, even absent the changes proposed in this filing."[100] Just as the Commission rejected PJM's IRD proposal because it was "likely to result in artificially inflated prices and procure energy and reserves in a manner disconnected from actual system needs,"[101] the Commission should reject PJM's current proposal that will yield prices that do not reflect system conditions.

In another Section 205 proceeding, the Commission rejected a PJM proposed tariff change that would "limit bonus payment eligibility to committed capacity resources."[102] Although PJM argued the proposal would "enhance reliability and incentivize capacity market participation," the Commission determined that PJM had not demonstrated its proposal would "achieve those objectives."[103] The Commission found that limiting bonus payment eligibility to encourage a smaller

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[98] *Id.* at P 47.

[99] *Id.*

[100] *See supra* n.10.

[101] *Id.* at p 48.

[102] *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,097 at p 126 (2024), *reh'g denied*, *PJM Interconnection, L.L.C.*, 187 FERC ¶ 62,016 (2024).

[103] *Id.*

group of resources to perform during emergencies had to be balanced against the reduced performance incentives for many other resources that would not receive a bonus.[104] The Commission found that PJM's proposal "would not enhance reliability and incentivize capacity market participation" and instead "could reduce PJM's ability to maintain resource adequacy during times of system stress" and it therefore, rejected PJM's proposal as unjust and unreasonable.[105] PJM's current tariff proposal in this proceeding similarly jeopardizes reliability and resource adequacy when its system is stressed and similarly should be found unjust and unreasonable. Consistent with its long history of rejecting unjust and unreasonable Section 205 tariff proposals, the Commission should reject the PJM Price Cap Proposal as unjust and unreasonable.[106]

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[104] *Id.*

[105] *Id.*

[106] *See, e.g.*, *Duquesne Light Company*,189 FERC ¶ 61,181 at P 43 (2024)(rejecting tariff revisions that contravened principles in prior order), *reh'g denied*, 190 FERC ¶ 62,075 (2025); *Southwest Power Pool, Inc.*, 189 FERC ¶ 61,122 at P 27 (2024)(rejecting tariff provision as unjust and unreasonable that could lead to "inefficient market outcomes"), *order denying reh'g*, 190 FERC ¶ 62,033 (2025); *Duke Energy Carolinas, LLC*, 189 FERC ¶ 61,073 at P 24 (2024)(rejecting tariff provision that would allow for recovery of regulatory assets without prior Commission approval because it was "impermissible under Commission precedent"); *Midcontinent Independent System Operator, Inc.*, 186 FERC ¶ 61,054 at P 173 (2024)(rejecting Section 205 filing providing for exemptions to a cap due to "the potential to undermine the reasons for imposing a cap" and the potential for "significantly diluting or erasing the efficiency, transparency, and other benefits MISO contends will result from imposing a cap"), *order denying reh'g*, 187 FERC ¶ 61,031 (2024); *Calpine Corporation v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,034 at P 30 (rejecting PJM tariff proposal as unjust and unreasonable and finding that Commission may make such a finding without waiting "until harm has been fully realized" and "can act based on factual predictions supported by economic analysis to prevent harm from impacting the market"), *order on reh'g*, 171 FERC ¶ 61,035 (2020).

V. CONCLUSION

Because PJM has not shown that its proposal is just and reasonable and not unduly discriminatory, and the proposal in fact will jeopardize reliability and resource adequacy and undermine important market signals indicating the need to retain existing generation with critically needed attributes and attract new investment, the proposal must be rejected. While America's Power is not indifferent to the affordability of electricity, it believes both reliability and affordability can be achieved by properly functioning markets. PJM's filing will not lead to a properly functioning market.

Much is at risk, and America's Power urges the Commission to recognize these risks and act promptly to reject PJM's filing for all of the reasons provided herein.

Respectfully submitted,

<u>/s/ Michelle Bloodworth</u>
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America's Power
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(202) 459-4803
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March 17, 2025

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the proceeding.

Dated at Washington, D.C., this 17th day of March, 2025.

/s/Michelle Bloodworth
Michelle Bloodworth

ATTACHMENT A

Mark Takahashi
Chair, Board of Managers

PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Via Electronic Delivery

December 9, 2024

Dear Stakeholders,

This correspondence conveys perspectives from the PJM Board of Managers (Board) on the filings related to enhancements to the interconnection process and adjustments to the capacity market. The Board expresses its sincere gratitude to all stakeholders for your thoughtful and robust engagement on these matters; your feedback helped to shape PJM's proposals and informed the Board's review and analyses of these efforts.

The Board is aware that the discussions on the matters addressed herein were advanced quickly. PJM finds great value in the contribution of its stakeholders and generally prefers as robust a process as possible for any given issue. This expedited process was necessary to be able to effectuate future capacity market auctions in accordance with the timeline reviewed by Federal Energy Regulatory Commission (FERC) in granting the extension in Docket No. ER25-118-000, as well as PJM's pressing reliability needs. In this instance, immediate action is required. As PJM has been warning for some time now, our region is experiencing a combination of trends that are rapidly tightening the supply-demand balance on our system. These trends include:

- Electrification coupled with the proliferation of high-demand data centers resulting in material forecasted load growth for the foreseeable future;
- Retirement of thermal generators at a rapid pace due to policy and economic pressures;
- Slow new entry of replacement generation resources due to a combination of industry forces, including siting, permitting and supply chain constraints; and
- The significant volume of resources in the interconnection queue that are being processed pursuant to the FERC's order on PJM's interconnection process reform, with a high proportion of the queue consisting of intermittent resources that don't have the same capacity value and operational characteristics as the retiring thermal generating fleet.

Taking the anticipated 2025 load forecast into account, the PJM system could see a capacity shortage as soon as the 2026/27 Delivery Year. To try and mitigate the risk of such an outcome, the Board supports the efforts outlined here that are intended to (1) bring capacity online more expeditiously through the interconnection queue; and (2) make sure price signals accurately reflect current supply-demand fundamentals. The suite of proposed filings is aimed at these objectives and addresses a generational change in our industry that requires both thought leadership and action. We do not expect that these filings, taken in aggregate, will fully resolve the resource adequacy challenge that we are facing, but we believe we must take the entire suite of actions to address the immediate reliability need. We expect for PJM and the stakeholders to continue to deliberate and act on this issue of utmost criticality and to bring their best proposals forward.

Board Supported Filings

Below is a description of filings that the Board supports, along with the Board's response to particular feedback we heard from stakeholders through discussion in the stakeholder process as well as through posted *ex parte* Board communications:[1]

Capacity Interconnection Rights (CIR) Transfer Reforms

CIR Transfer Reforms were developed through the stakeholder process and were endorsed by the Members at the November 21 Markets & Reliability Committee and Member Committee meetings. The Board is pleased that stakeholders supported a reform package that will facilitate an expedited interconnection process for a replacement resource seeking to utilize the CIRs of a deactivating resource. As endorsed, the Replacement Generation Interconnection Process would stand alone outside of the PJM Cycle Process and operate in parallel. This better aligns the timing of de-energizing deactivating resources and the energizing of their replacements. The expedited timing allows replacement resources to execute an interconnection agreement sooner and also allows for their inclusion in RTEP models sooner to support reliability studies. PJM plans to make this filing early in 2025. This is a sensible reform effort that was stakeholder driven, and the Board supports it.

Surplus Interconnection Service (SIS)

PJM presented a proposal to streamline existing SIS Tariff provisions to allow for new generators that do not trigger transmission system upgrades to use an existing generator's unused interconnection capability and avoid being processed through the generation interconnection queue. An example of a resource pairing utilizing SIS is a renewable resource combined with battery storage. By taking a less restrictive approach to SIS, PJM will be in a better position to maximize system benefits and enhance resource adequacy without the need for additional network upgrades. The Board supports PJM's proposal, and PJM intends to make a near-term filing on SIS.

Reliability Resource Initiative (RRI)

The RRI represents a narrowly tailored, limited duration proposal designed to expedite the interconnection of a limited number of "shovel ready" generating resources that are not presently in the Transition Cycle #2 (TC2) interconnection queue. This proposal reflects the growing urgency to connect generating resources that have a high likelihood of being able to materially support resource adequacy and maintain grid reliability in the near term. Resources that are selected for participation in the RRI will be required to participate in the Reliability Pricing Model (RPM) auctions for 10 delivery years. Additionally, the current RRI proposal is fuel and technology neutral and allows all generating resources to apply including renewable generation.

Since the RRI proposal was initially presented to stakeholders at a special session of the Planning Committee on October 18, 2024, PJM has considered both the constructive and critical feedback received during that presentation and subsequent stakeholder meetings and discussions held in November. PJM also invited parties to file written

[1] This letter also serves as response to the myriad *ex parte* communications to the Board on these issues that PJM duly circulated to the Members Committee list and that are publicly available at this link: https://www.pjm.com/about-pjm/who-we-are/pjm-board/public-disclosures

comments. In response to extensive feedback, PJM made significant adjustments to its initial RRI proposal. Changes to the proposal included reducing the maximum number of qualifying RRI projects from 100 to 50, ensuring that all types of resources are eligible to apply by eliminating gating criteria in favor of a weighted scoring criteria, and adjusting scoring criteria and weighting (e.g., adding locational value).

While concerns have been expressed that the RRI proposal lacks sufficient foundation or a record of support, the facts on the ground show otherwise. As evidenced in PJM's energy transition analyses, including the Energy Transition in PJM: Resource Retirements, Replacements & Risks report (i.e., the "4R" report) from last year, the growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of large data centers in the region. Simultaneously, existing thermal generation is retiring at a rapid pace due to a combination of government and private sector policies and is outpacing new entry. Last, the recent pricing of capacity and a reduction in the reserve margin expresses a clear indication that new and immediate supply is needed on the system. If these trends continue as projected, we risk having insufficient resources later in this decade to maintain the reliable electric service that the public expects. This particular slide from PJM's presentation on the RRI is especially concerning. This slide shown below demonstrates that PJM will need anywhere from 62% to 100% of the resources currently in its queue to achieve commercial operation to maintain resource adequacy without additional intervention. The historical completion rate from the queue is approximately 10%.

PJM 2030 Reliability Scenario Balance Sheet

	Study Year: **2030/31** Forecasted Summer Peak: **167,876** Preliminary Forecast Pool Requirement: **0.9296**	Scenario: **0%** New Entry (GW)	**40%*** New Entry (GW)	**62%** New Entry (GW)	**100%** New Entry (GW)
Supply	2025/26 ELCC Adjusted Offered Capacity*	145	145	145	145
Supply	ELCC Adjusted Forecasted Deactivations (2025-2030)	-17	-17	-17	-17
Supply	ELCC Adjusted New Resource Entry Rate	0%	40%	62%	100%
Supply	ELCC Adjusted New Resource Entry	-	18	28	45
	Total ELCC Adjusted Available Capacity	128	146	156	173
Demand	**Preliminary Reliability Requirement** *(Forecast Summer Peak * Forecast Pool Requirement)*	156	156	156	156
	Balance Sheet	**-28**	**-10**	**0**	**+17**

*Includes estimated FRR resources committed for the 25/26 Delivery Year.
*As stated when presenting the ELCC Class Ratings for the period, the IRM/FPR values are "for informational purposes" only. The values are not and should not be interpreted as a PJM forecast of IRM/FPR. Rather, they are the outcome of running the ELCC model using a specific assumed resource portfolio for each delivery year in the period. Significant uncertainty surrounds each assumed resource portfolio.
*40% still higher than historical average

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It is important to note PJM's load forecast will be increasing from these levels to reflect growing data center demand. This will exacerbate the need for new resources. We also recognize the criticism that the decision to allow certain new resources to join TC2 has the potential to impact other resources that are currently in the queue. However, the RRI proposal's accommodation of no more than 50 new resources is not intended or expected to destabilize the queue or otherwise lengthen the study time for the current TC2 projects, which are scheduled to be processed in 2025–26. The Board acknowledges that this initiative presents transmission cost uncertainty for projects currently in TC2. We took a hard look at various study alternatives to determine the impact with and without the additional resources; however, this approach would introduce an unacceptable delay of six to eight months. Additionally, depending on the characteristics and location of a resource that participates in the RRI, it is possible that reduced transmission upgrade costs through a greater pool of participants could benefit projects that are currently awaiting processing in TC2.

In response to the states' position that the RRI proposal should not interfere with the states' authority over generating resources, we want to make clear that the RRI proposal does not infringe on such authority. Under the RRI proposal, the restructured states in PJM will continue to rely upon the competitive markets to attract private developers to construct generation resources, while the vertically integrated states would continue to definitively control their generation mix though the approval of their integrated resource plans. Regardless of the regulatory model, the goal of the RRI proposal is to have new resources enter the interconnection queue earlier, resulting in more megawatts on the system sooner than would be the case without the RRI.

Further, in written comments submitted by Pennsylvania Gov. Shapiro on November 20, 2024, the governor recommended that PJM rely on the expertise of the states in PJM to assist in the determination of an RRI project's viability in terms of state permitting and site readiness. We appreciate this suggestion and welcome any and all engagement from the states that would help PJM to determine a project's viability, subject to timing considerations and possible confidentiality restrictions.

The Board understands that the stakeholders are particularly divided on the RRI proposal. PJM's primary responsibility is to maintain grid reliability. It should not be an acceptable outcome to any PJM stakeholder to allow the grid to fail based upon financial or other interests. One needs only to recall the recent harm inflicted upon consumers during Winter Storm Uri in the Southwest as an example of the potential consequences for consumers should grid reliability be lost. Based upon all available data, including data embedded in this correspondence, PJM is facing a meaningful resource adequacy risk. Thus, for the benefit of grid reliability and consumers across the footprint, the Board supports PJM staff's RRI proposal.

Capacity Market Adjustments

PJM's capacity market is working as designed to reflect supply-demand conditions in the RTO. July's 2025/2026 Base Residual Auction (BRA) sent a signal reflecting the need for more capacity on the system. PJM is consistently seeking to perfect this marketplace because it is conscious that consumers ultimately will pay for the auction's results. Thus, the market should reflect supply-demand fundamentals and evolve as the system evolves. PJM staff has presented reforms that are modest, are sensible and reflect system realities. To note, these reforms were initially proposed by a combination of load interests and generation owners – a pairing of interests that is atypical in the PJM sphere.

Staff's proposal addresses four areas: (1) maintain a dual fuel combustion turbine (CT) as the reference technology as an input in to the Variable Resource Requirement (or demand) curve; (2) set a uniform non-performance charge rate at RTO Net Cost of New Entry (Net CONE) of the dual fuel CT; (3) remove reactive services from Energy & Ancillary Services Offset (compliance with FERC Order No. 904); and (4) include Reliability Must-Run (RMR) units in capacity market supply when they meet certain criteria.

1. ***Dual Fuel CT as Reference Technology***

   The Board supports PJM's proposal to maintain the dual fuel CT as the reference technology rather than moving to the combined cycle gas technology (CC) that was adopted in the 2022 Quadrennial Review of the VRR curve, and accepted by FERC to be implemented starting with the 2026/27 BRA. Using the dual fuel CT will mitigate the steepness of the curve and, for the most part, the issues associated with a $0/MWd Net CONE. The Board heard questions regarding whether dual fuel CTs are being sited on the system and PJM responded in the affirmative.

2. ***Uniform Non-performance Charge Rate***

   The Board also supports PJM's proposal to implement a uniform non-performance charge rate at the RTO Net CONE. As PJM has explained, this will: (1) address significantly lowered risk of the lack of non-performance charges in zones where the Net CONE is $0/MWd; (2) address arguments regarding discrimination given the non-uniformity of the penalty rate (ISO-NE implements a uniform non-performance charge rate across their footprint); and (3) establish broader, regional performance assessment intervals – or PAIs – rather than previous locational ones. In regard to stakeholder feedback on establishing a price cap by modifying the formula for Point A of the VRR curve, the Board is supportive of PJM's decision not to modify its formula for Point A at this time. Specifically, PJM has explained that its approach is consistent with other ISO/RTOs – such as the New York ISO's use of 1.5*Gross CONE, and ISO-NE's starting price being greater than or equal to Gross CONE – and that no studies have been conducted on the use of 1.5*Net CONE as a reasonable level. This topic is being discussed as part of the Quadrennial Review. The Board also understands that maintaining status quo of the reference unit to the VRR curve will effectuate the change of reducing the price cap for the next auction.

3. ***Removing Reactive Service Revenue Component From Net Energy and Ancillary Services Offset***

   PJM also proposes to address one aspect of the compliance directive from FERC's final rule on Reactive Service Rates in Order No. 904 – to remove the reactive service revenue component from the Net Energy and Ancillary Services Revenue Offset for the Reference Resource and from the default minimum floor offer prices – as a severable part of its filing. The Board understands this will ensure the capacity market-related aspects of Order No. 904 are in place for the 2026/27 Delivery Year, which aligns with the anticipated 2026 effective date of the broader compliance directives.

4. ***Inclusion of RMR Units as Capacity Under Certain Criteria***

   Finally, the Board supports PJM's proposal to include RMR units as capacity market supply when they meet certain criteria. The Board heard feedback on various aspects of this proposal, but believes that the PJM proposal struck the appropriate balance to recognize the capacity value and thereby partially offset RMR costs to consumers who are paying for the RMRs, while ensuring resources counted as capacity can contribute in a manner comparable to other capacity resources. That is, the RMR unit must reasonably be expected to operate for the entire delivery year in accordance with applicable permits and legal restrictions; be required to be available for PJM dispatch in expectation of all PJM emergencies, so long as the unit is not on an outage; and have CIRs and be deliverable. Based on feedback received, PJM removed one of the criteria presented at the November 21 MC – that the RMR unit has available run hours greater than those expected to be needed for transmission support. PJM heeded feedback that this would be too subjective and difficult to determine and the Board supports PJM's removal of this criteria.

5. ***Update: Other Capacity Market Reform Requests***

- Enhancements to the Effective Load Carrying Capability (ELCC) framework have been brought to the stakeholder process via a new problem statement/issue charge. Our goal is to have these enhancements in effect for the 27/28 BRA.
- PJM would like to explore a sub-annual market construct with the stakeholders. This is a longer-term endeavor that will require more analytical rigor, but PJM does hope to move this effort forward soon.
- The Board is aware that PJM staff recently indicated its desire to make a separate filing on a "must offer" requirement for all resources with CIRs and related Market Seller Offer Cap (MSOC) changes in time for the 26/27 BRA. The Board supports PJM staff's exploration of the matter and its desire to consult with the stakeholders. The Board has yet to make a determination as to whether it supports such a filing. Rather, the Board wants to hear stakeholder feedback prior to making any such decision.

In summary, the PJM Board supports the staff in making filings to reform the CIR transfer process, the SIS process, the RRI and the four capacity market adjustments set forth above. The filings for SIS, RRI and the capacity market will be made soon after this correspondence is sent. The filing for CIR transfer will be made in early 2025. As to the "must offer" requirement, our understanding is that this filing would need to be made within the next few weeks in order for the requirement to be integrated into the 26/27 auction framework. Thus, the stakeholders should anticipate further correspondence expressing the Board's thoughts on that subject after the stakeholder consultation.

The Board again expresses our appreciation to the stakeholders on these critical and timely matters. You have been thoughtful in both bringing suggestions and proposals to PJM and providing feedback on them during stakeholder meetings.

Sincerely,

Mark Takahashi
Chair, PJM Board of Managers

ATTACHMENT B

FEBRUARY 2025

Operation of the U.S. Power Grid During the January 2025 Polar Vortex

Prepared for:

AMERICA'S POWER

Reliable • Secure • Resilient • Affordable

Prepared by:

ENERGY VENTURES ANALYSIS

ENERGY VENTURES ANALYSIS

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Executive Summary

The January 2025 Polar Vortex pushed the U.S. power grid to unprecedented limits as record-breaking low temperatures and extreme weather conditions pushed electricity demand to historic levels. Across multiple power market regions, electricity demand during the event set new single-day demand records as heating demand across sectors spiked. In response, grid operators relied heavily on dispatchable generation—primarily coal and natural gas—to ensure system reliability and stabilize supply during the extreme event.

This report analyzes and highlights how power generation across the country responded to the exceptional winter weather event in January 2025. Some of the national and regional highlights of the report include:

- **Critical Ramp-Up of Coal:** Coal-fired power plants dramatically increased their output during the Polar Vortex. In many regions, capacity factors for coal soared above 80%, far exceeding typical winter levels. This robust performance was essential, as variable renewable resources (such as wind and solar) underperformed due to adverse weather conditions. Coal's ability to increase electric output substantially ensured that approximately one-fourth of the total generation mix during peak hours came from coal-fired power plants, offsetting significant fluctuations in renewables and meeting the incremental electricity demand.

- **Role of Natural Gas and Other Fossil Fuels:** Natural gas generation also increased markedly to meet the surge in demand. However, while natural gas units ramped up production, they faced volatile fuel costs amid heightened heating and electricity demand needs. Other fossil sources like oil-fired generation, although normally minor players, were called upon to bridge shortfalls during peak periods.

- **Reduced Price Volatility via Increased Coal Dispatch:** In the PJM region, where electricity demand reached new highs (with peak demand exceeding 132 GW), coal-fired plants proved to be vital economic assets. As natural gas prices spiked—from under $2/MMBtu in November to nearly $30/MMBtu at the height of the event—coal's stable fuel cost (around $2.50/MMBtu) allowed for increased coal plant dispatch and limited wholesale power price spikes. Coal plants, therefore, moved from a marginal resource in November to a primary electricity supply resource, with capacity factors increasing to nearly 70% during the event.

- **Impact on Wholesale Power Prices:** The PJM case study demonstrated that coal's dispatchability was key in containing power price spikes. PJM's average day-ahead power prices peaked at about $225/MWh on January 21. A hypothetical analysis revealed that without coal-fired generation, prices could have soared to over $400–$650/MWh—potentially adding between $500 million and $1.4 billion in extra costs for consumers. This stark contrast underscores coal's role as a de facto price hedge in times of extreme demand.

The January 2025 Polar Vortex underscored the indispensable role of dispatchable generation in maintaining grid reliability and controlling wholesale power prices under extreme weather conditions. Coal-fired power plants, with their on-site fuel storage and stable fuel costs, proved critical in bridging the demand gap when renewable output was constrained, and natural gas prices became highly volatile. The PJM power price case study, in particular, highlights how the continued operation of coal resources can prevent massive cost escalations for electricity consumers during such events. These findings emphasize the importance of a balanced energy mix that includes resilient, dispatchable assets alongside renewables to ensure energy security and affordability in the face of future extreme weather challenges.

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Table of Exhibits

List of Abbreviations and Definitions

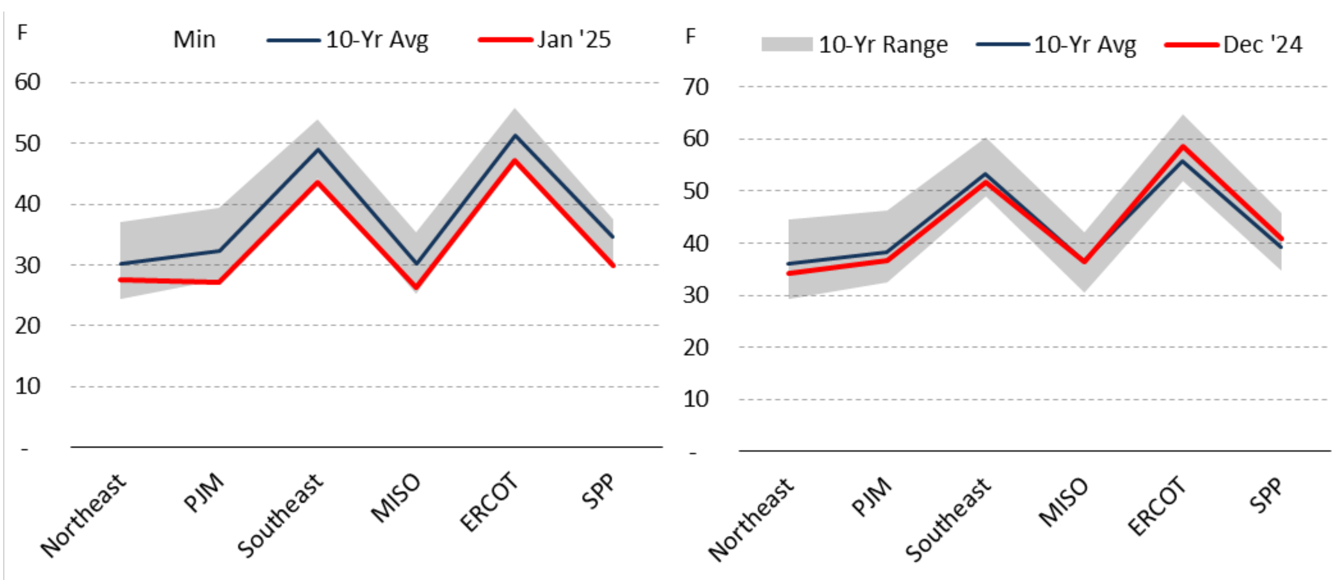
- **DAM** – Day-Ahead Market: A wholesale electricity market where prices and generation schedules are determined one day in advance.
- **EIA** – Energy Information Administration: A U.S. government agency that collects and analyzes energy data.
- **ERCOT** – Electric Reliability Council of Texas: The independent system operator managing the Texas power grid.
- **GW** – Gigawatt: A unit of power equal to one billion watts.
- **ISO** – Independent System Operator: An entity responsible for managing regional electricity markets and ensuring grid reliability.
- **MISO** – Midcontinent Independent System Operator: The system operator managing the power grid across parts of the Midwest and South.
- **MW** – Megawatt: A unit of power equal to one million watts.
- **PJM** – PJM Interconnection: The largest regional transmission organization in the U.S., covering 13 states and Washington, D.C.
- **RTO** – Regional Transmission Organization: An entity responsible for managing and coordinating electricity transmission over large geographic areas.
- **SPP** – Southwest Power Pool: An independent system operator that manages the electricity market in central U.S. states.
- **VOM** – Variable Operating and Maintenance Costs: Costs that vary based on electricity generation, including fuel and maintenance expenses.

Introduction

Arctic air rolled through many of the lower-48 states of the United States from the late hours of January 19th to January 23rd, bringing a stretch of extreme cold weather to the on-average coldest time of the year for much of the country. This extreme weather event was characterized by dramatic distortion of the upper-atmospheric circulation called the "Polar Vortex," which resulted in the widespread intrusion of frigid Arctic air into mid-latitude regions. Termed the "January 2025 Polar Vortex" for the context of this report, this event led to record-breaking low temperatures in parts of the country, stressing residential and commercial heating systems and regional power grids.

Polar vortex distortions were detected as early as the end of 2024 to early January 2025, leading to the coldest January in ten years across various power market regions in the country. Averaging at the minimum of the ten-year range of temperatures, as seen on the chart on the left in **EXHIBIT 1**, the first couple of weeks of January were characterized by escalated coal and natural gas generation. In comparison, as shown in the chart on the right in **EXHIBIT 1** below, the regional temperature averages for December 2024 largely aligned with the ten-year averages and were well within the observed temperature ranges. Subsequently, for the purpose of this report, the primary demand and generation analyses have been conducted using the December 2024 observed numbers as the baseline for a winter month with near-average weather-related electricity and fossil fuel demand.

EXHIBIT 1: JANUARY AND DECEMBER TEMPERATURE AVERAGES VS. 10-YEAR TEMPERATURE AVERAGES FOR MAJOR U.S. POWER MARKETS



Source: NOAA, Frontier Weather

This stretch of cold weather led to record-breaking highs in electricity demand in some regions of the country. Cautioned by weather forecasting models, the grid displayed a higher degree of preparedness in comparison to previous extreme weather events. As discussed within this report, dispatchable generation, i.e., coal and natural gas, were already operating with higher utilization in the early weeks of January than in December due to the sustained below-average temperatures for much of January. Daily median temperature charts for January 2025 for the regions analyzed in this report are provided in the Appendix.

Regional Analysis

Using EIA's regional data from the Hourly Electric Grid Monitor, EVA performed analyses of the impact and performance of the power market regions shown in **EXHIBIT 2**.[1,2] The power market regions are presented in the order of the winter storm's impacts on their respective power systems.

EXHIBIT 2: MAP OF POWER MARKET REGIONS

Regional Aggregate Results

Between January 20 and January 22, 2025, much of the affected Lower 48 states experienced significantly below-average temperatures, leading to a surge in electricity demand. **EXHIBIT 3** presents the top 100 electricity demand occurrences across the combined territories of SPP, ERCOT, MISO, PJM, the Southeast, and the Northeast (referred to as the "Regional Total"). The polar vortex in January 2025 resulted in the highest and second-highest electricity demand levels on record, reaching 537 GW and 528 GW, respectively—nearly 150 GW above the regional average of approximately 390 GW. These demand levels surpassed those observed during previous extreme weather events, including the Jan'24 Winter Storm and Winter Storm Elliott during December 2022, by nearly 35 GW and 37 GW, respectively.

[1] Northeast = EIA Grid Monitor regions NY & NE; PJM = MIDA; Southeast = TEN, CAR, SE & FLA; MISO = MIDW; ERCOT = TRE; SPP = CENT; WECC = NW, SW & CAL. Further detail on which balancing authorities make up the EIA regions can be found here: https://www.eia.gov/electricity/930-content/EIA930_Reference_Tables.xlsx

[2] WECC is excluded from the report as the data analysis showed little impact on the WECC power systems during the January 2025 polar vortex.

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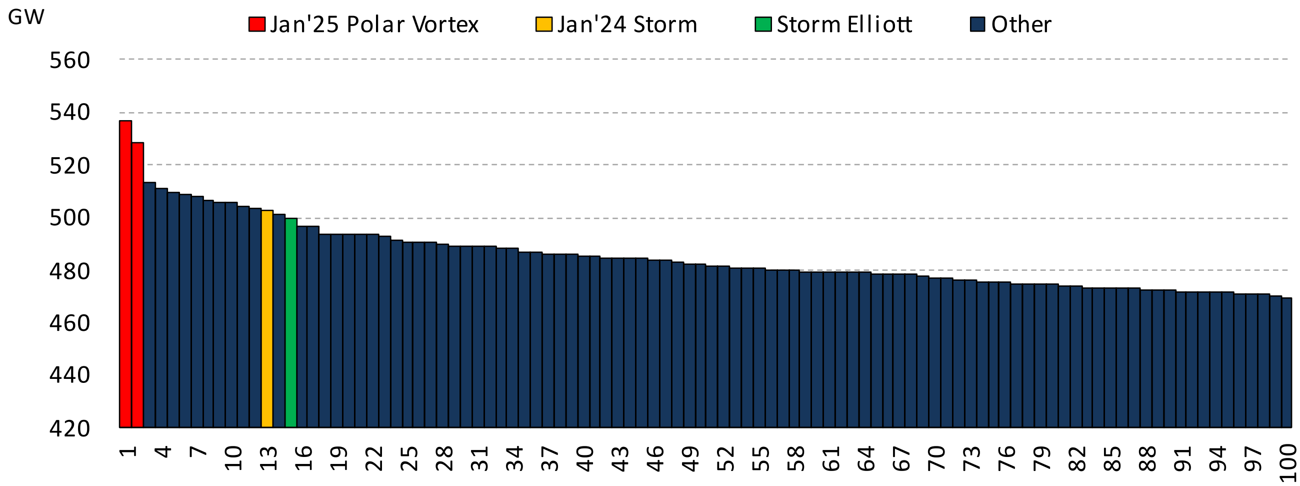
EXHIBIT 3: REGIONAL TOTAL - TOP 100 ELECTRICITY DEMAND DAYS

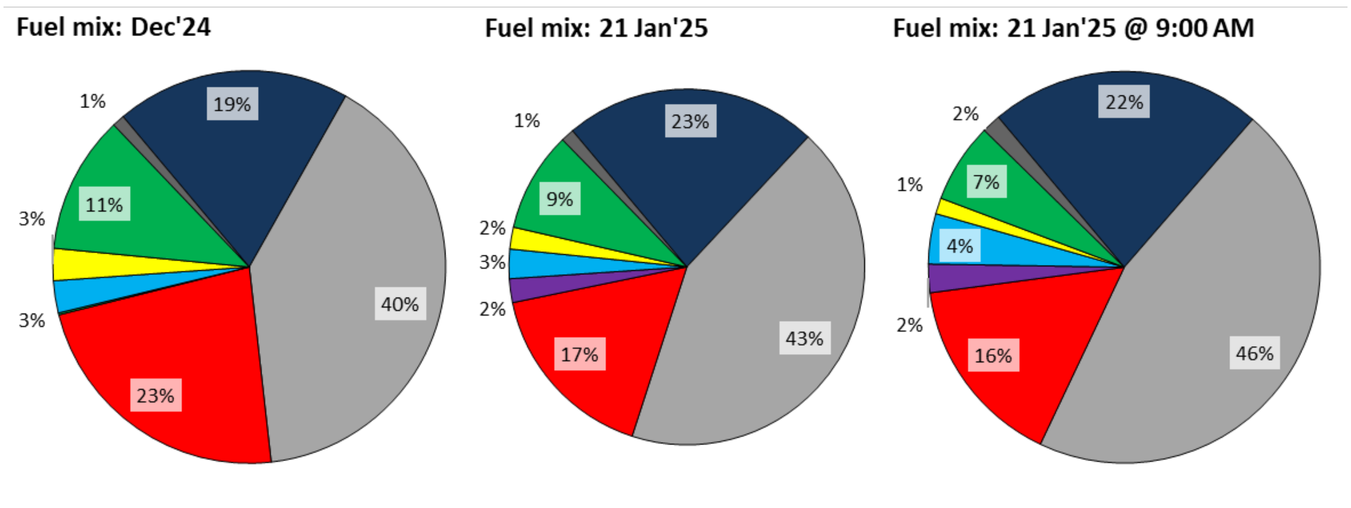


Source: EIA Hourly Grid Monitor

On a broader scale, peak electricity demand during the event occurred on January 21, reaching its apex at 9:00 AM. A comparison of the generation mix for the affected regions during the peak demand day and hour to the average hourly generation during December 2024 highlights a predominant reliance on natural gas and nuclear power, followed by coal and wind. While the overall fuel mix on January 21 remained relatively consistent with the seasonal average, there was a notable increase in coal and natural gas generation, as illustrated in **EXHIBIT 4**.

During the peak hour, coal accounted for approximately one-fourth of total generation, while wind output saw a notable decline compared to its average contribution during December 2024. Solar generation also dropped to one-third of its usual share as solar radiation during early morning hours in the winter months is minimal. In contrast, natural gas usage increased significantly, becoming the dominant source of generation with a 46% share of total electricity output.

EXHIBIT 4: REGIONAL TOTAL - GENERATION MIX

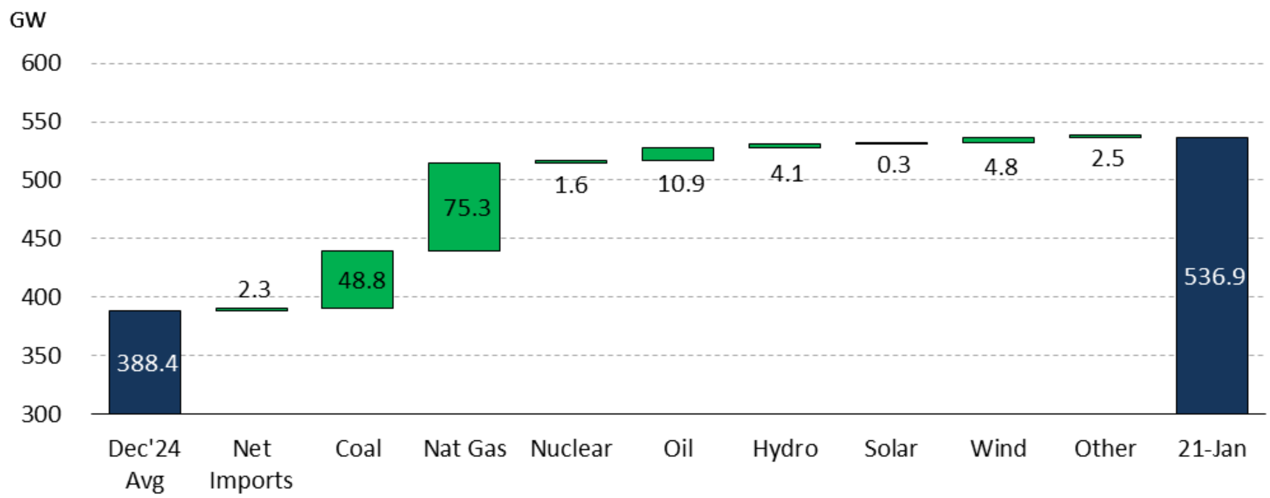


Source: EIA Hourly Grid Monitor

During the January 2025 Polar Vortex, electricity demand peaked on January 21, surging nearly 150 GW above the average hourly electricity demand in December 2024. Approximately 70% of this increased demand was met by fossil fuel generation, primarily from coal and natural gas, which contributed an additional 50 GW and 75 GW, respectively, compared to their December 2024 average hourly generation, as illustrated in **EXHIBIT 5**.

Oil-fired generation, which usually accounts for less than 1 GW, saw a significant ramp-up, providing an additional 11 GW to help meet the record demand. On the renewable side, wind and hydro collectively added 9 GW to the grid, while solar generation on the peak day remained consistent with its output from the previous month.

EXHIBIT 5: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

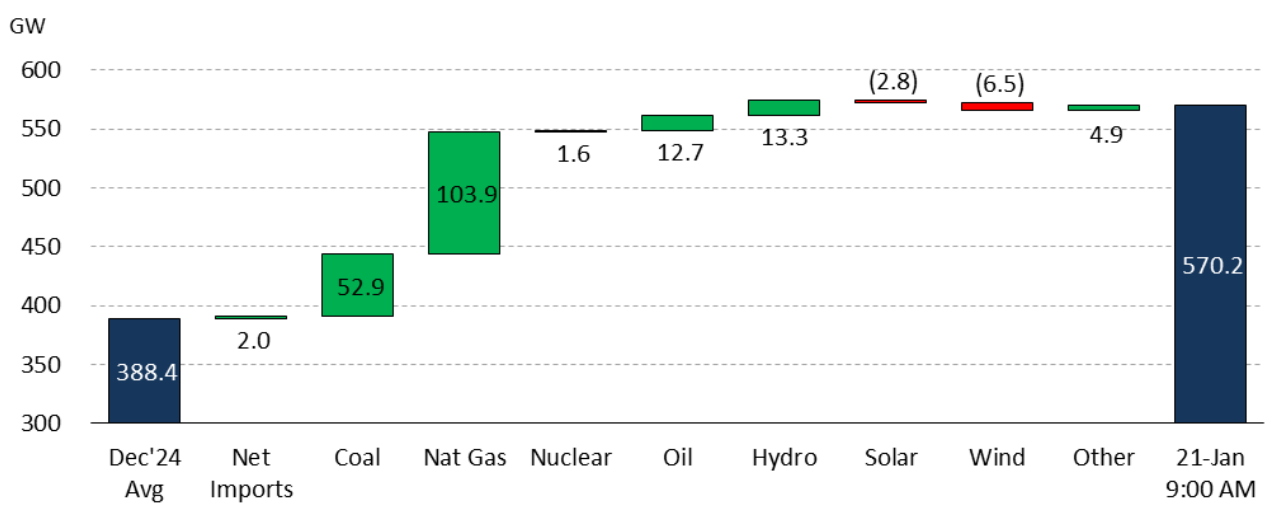


Source: EIA Hourly Grid Monitor

During the peak demand hour of the January 2025 Polar Vortex, electricity demand surged by approximately 180 GW compared to the December 2024 average hourly demand. Due to the peak occurring at 9:00 AM, solar capacity was insufficient to make a significant contribution. Both wind and solar generation experienced substantial declines, producing 6.5 GW and 2.8 GW less, respectively, than the previous month's contributions.

Fossil fuel generation supplied much of the increased demand, with natural gas providing an additional 104 GW and coal contributing another 53 GW compared to normal winter conditions, as illustrated in **EXHIBIT 6**.

EXHIBIT 6: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



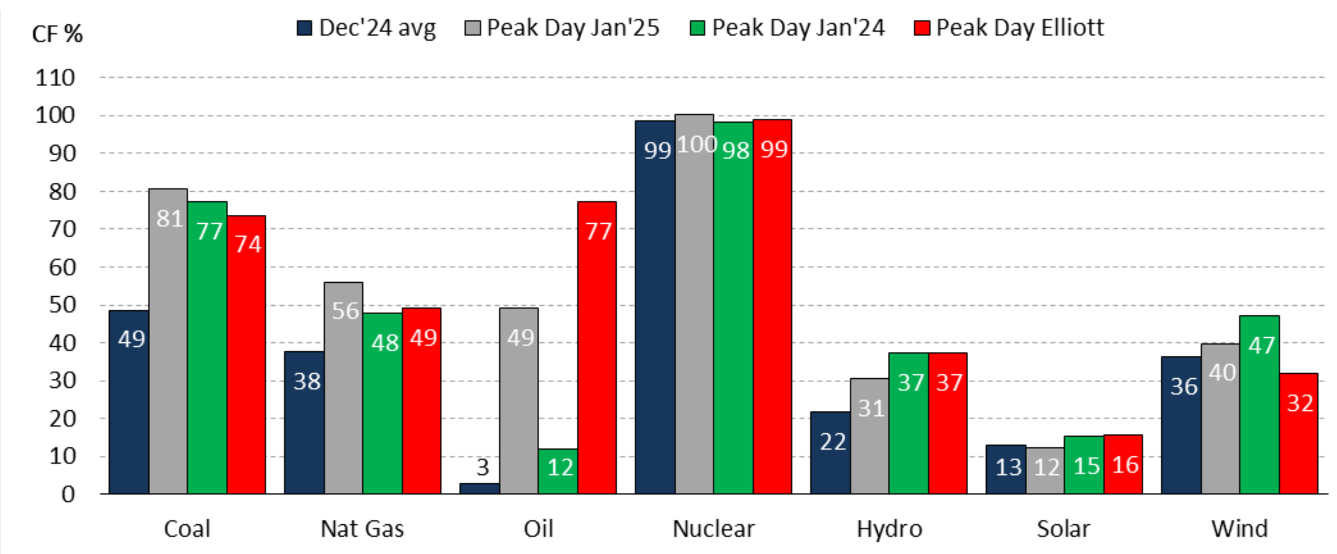
Source: EIA Hourly Grid Monitor

EXHIBIT 7 illustrates the capacity factors, or utilization rates, of various generating resources during peak demand periods compared to the average for December 2024. Capacity factors effectively capture the response and availability of different resource types for different extreme weather events like the January 2025 Polar Vortex, the January 2024 Winter Storm, and Winter Storm Elliott, independent of any resource additions or retirements that occurred between these events. Thus, it provides more equitable insights into the performance of each resource type and reflects variations in resource dispatchability during such critical situations. The capacity factors shown represent the average utilization of all operational generating resources of a given fuel type, regardless of individual unit availability during the observed periods.

Among the different resource types, coal-fired power plants exhibited the most significant increase in utilization across all three extreme weather events, excluding nuclear plants, which typically operate at nearly 100% utilization when available. During the peak demand day of the January 2025 Polar vortex, coal generation surpassed an 80% capacity factor, markedly higher than its December 2024 average and utilization levels during other extreme weather events, such as Winter Storm Elliott.

Natural gas-fired power plants also experienced a notable surge in capacity factors during peak demand days compared to December 2024, albeit at lower incremental rates than their coal-fired counterparts. In contrast, solar and wind generation contributed less significantly during these extreme weather events. Solar performance remained relatively consistent with its average generation in December 2024, while wind generation showed variability. Although wind operated at a slightly higher capacity factor during the peak demand day of the polar vortex compared to the previous month's generation, overall generation was significantly lower compared to the peak day of the January 2024 winter storm. Wind generation during the peak day of the Jan’25 Polar Vortex was 7 GW lower than during the Jan’24 storm, despite the addition of nearly 3.5 GW of wind capacity in 2024. This also highlights the intermittency of wind resources and raises questions about their reliability during extreme weather events.

EXHIBIT 7: REGIONAL TOTAL - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



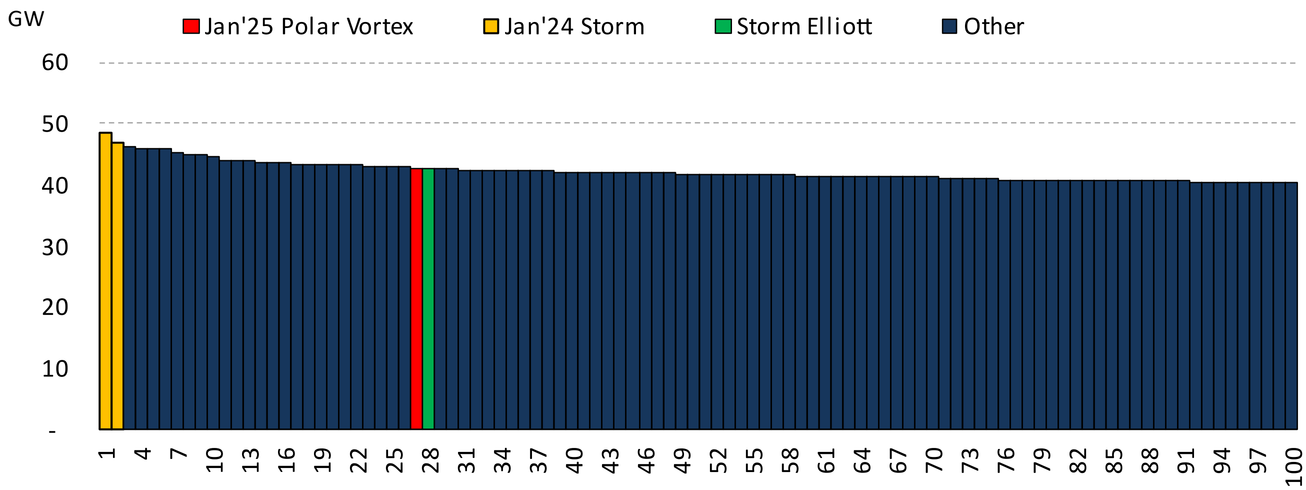
Source: EIA Hourly Grid Monitor & EIA 860 data

Southwest Power Pool

The Southwest Power Pool (SPP) is an independent system operator that manages the bulk electric grid and wholesale power market across a large area of the central United States. It serves nearly 19 million customers in 17 states, ranging from North Dakota to Louisiana.

The average demand in the region ranges between 30-35 GW. In January 2025, the Polar Vortex event resulted in one of the highest peak demands in SPP's history. On January 21, the average demand reached 42.7 GW, with a peak hourly demand of 45.3 GW. This average daily demand ranked among the top 100 demand days in history, specifically at 27th place, as illustrated in **EXHIBIT 8**. Notably, the highest electricity demand day during this Polar Vortex was comparable to and slightly exceeded the average demand on the peak day during Winter Storm Elliott.

EXHIBIT 8: SPP - TOP 100 ELECTRICITY DEMAND DAYS

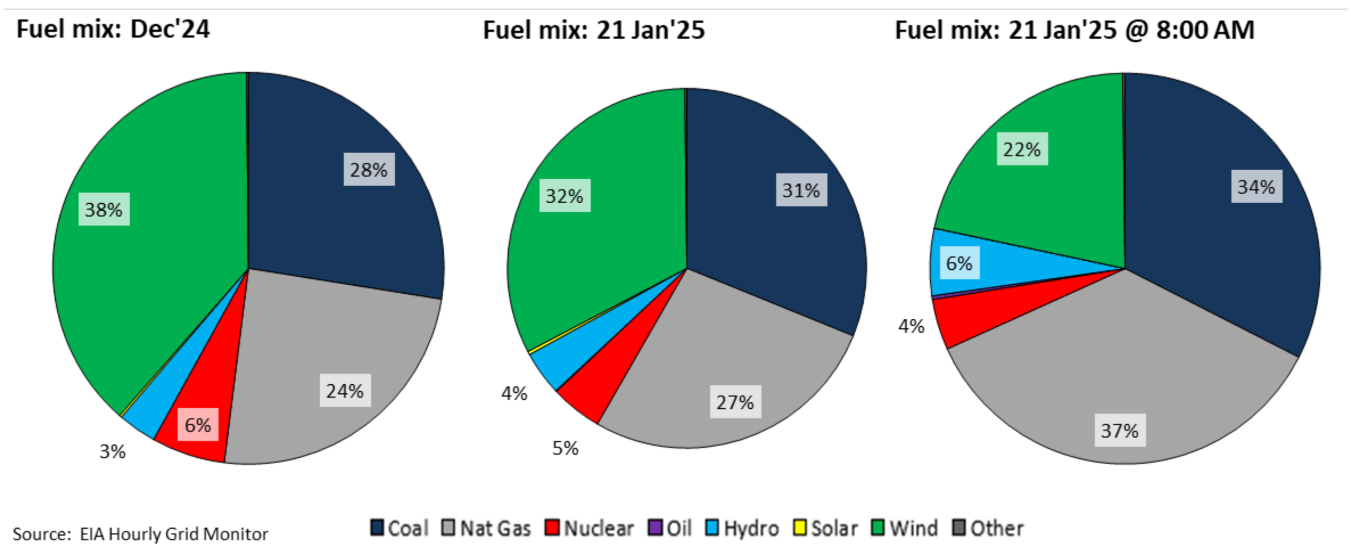


Source: EIA Hourly Grid Monitor

In December 2024, wind resources accounted for a significant portion of electricity generation in the Southwest Power Pool (SPP), making up 40% of the total. However, on January 21, when demand in the region reached its peak, the share of wind energy dropped to 32%. As demand increased, other energy sources stepped up their contributions to the grid, with coal becoming the primary source of added generation. During the peak demand hour on the morning of January 21, coal and natural gas together constituted 71% of the region's generation mix.

On January 21, wind generation averaged 14.2 GW, but it fell to 10.3 GW during the peak demand hour in the morning. This decline resulted in an increased dispatch of coal and natural gas to compensate for the shortfall, as seen in **EXHIBIT 9**.

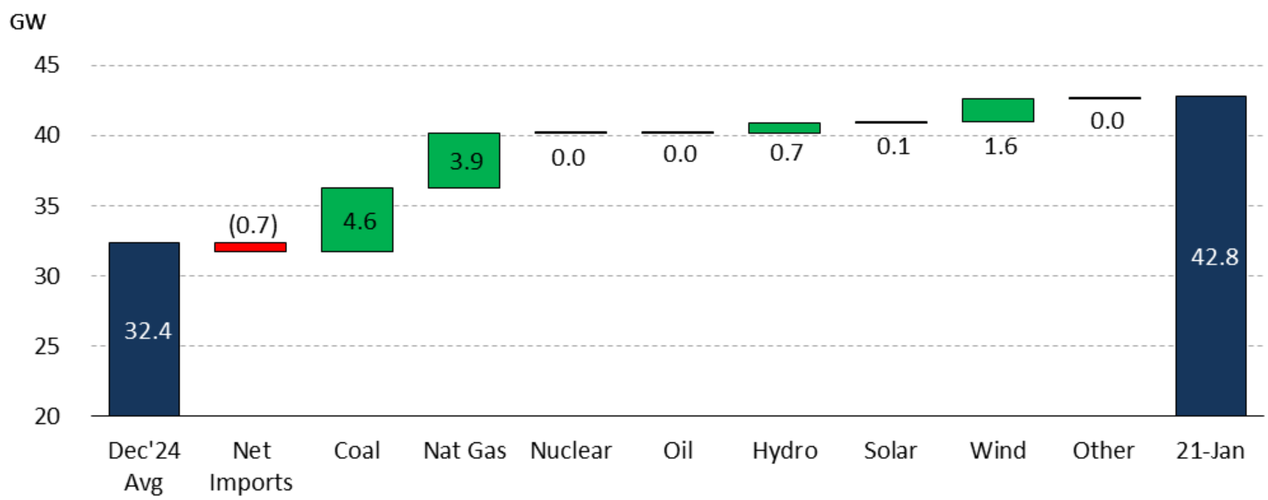
EXHIBIT 9: SPP - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 10 displays a comparative analysis of demand and generation from various fuel sources, focusing on average hourly operations during December 2024 and the peak demand day during the Polar Vortex in January 2025. Notably, on January 21, demand increased by approximately 10 GW to 42.8 GW, leading to a significant rise in coal and gas generation—by 4.6 GW and 3.9 GW, respectively—to ensure grid stability, contributing over 87% to the additional load. While wind and hydro generation saw a slight increase, solar generation experienced a net decline compared to the previous month's output.

EXHIBIT 10: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

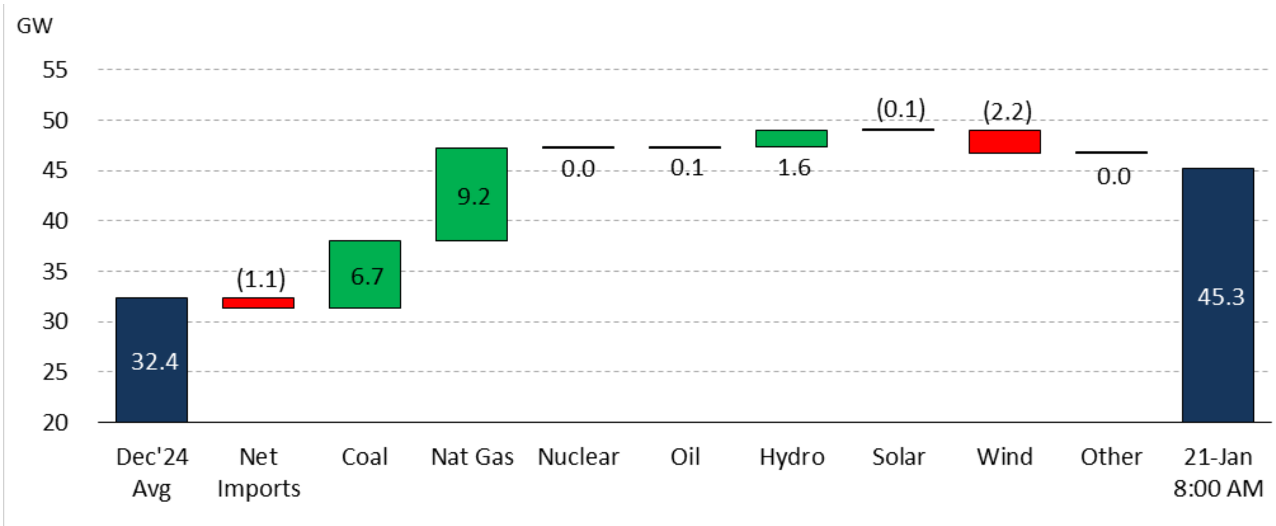


Source: EIA Hourly Grid Monitor

Similar to the previous chart, the analysis presented in **EXHIBIT 11** below offers a comparative analysis between the average hourly operations during December 2024 and the peak demand hour of the January 2025 Polar Vortex. In the SPP region, this peak occurred at 8.00 am on January 21, leading to a surge in demand of 45.3 GW.

On January 21, the daily average for wind generation was 14.2 GW; however, it decreased to 10.4 GW during the peak demand hour due to inclement weather conditions. In response, coal and natural gas generation increased substantially to meet the higher demand, rising to 15.7 GW and 17.2 GW, respectively. In comparison, during December 2024, daily coal and natural gas generation was only 9 GW and 8 GW on average, marking sharp increases of 74% and 115% in January.

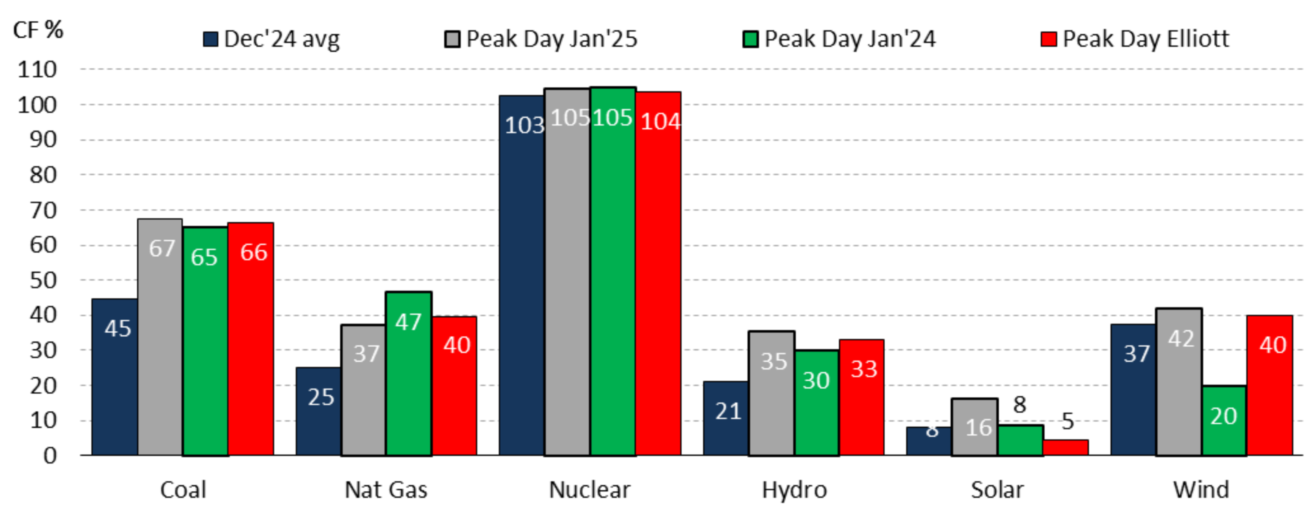
EXHIBIT 11: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 12 below illustrates the capacity factors of different types of generating resources during December 2024 and various periods of peak demand in comparison to January 21 in the SPP. Since absolute capacity numbers can change from year to year, capacity factors provide a more equitable metric for comparing how different fuel types respond to extreme weather events, such as the Polar Vortex and Winter Storm Elliott. As shown in **EXHIBIT 12**, coal generators significantly increased their utilization to meet the rising electricity demand. Notably, coal generation was already heightened in December, as there were anticipations of high demand due to the extreme cold. **EXHIBIT 12** also highlights the variability of solar and wind resources. Wind resources made a substantial contribution to meeting peak day demand and showed increased utilization from December averages, although they generated more electricity during non-peak hours on that day. Solar capacity factors, on the other hand, increased markedly from 8% in December 2024 to 16% on January 21, 2025, but remained low on average due to reduced solar irradiation and snow cover. In contrast, nuclear energy remained stable, while natural gas capacity factors increased from 22% to 35%.

EXHIBIT 12: SPP - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



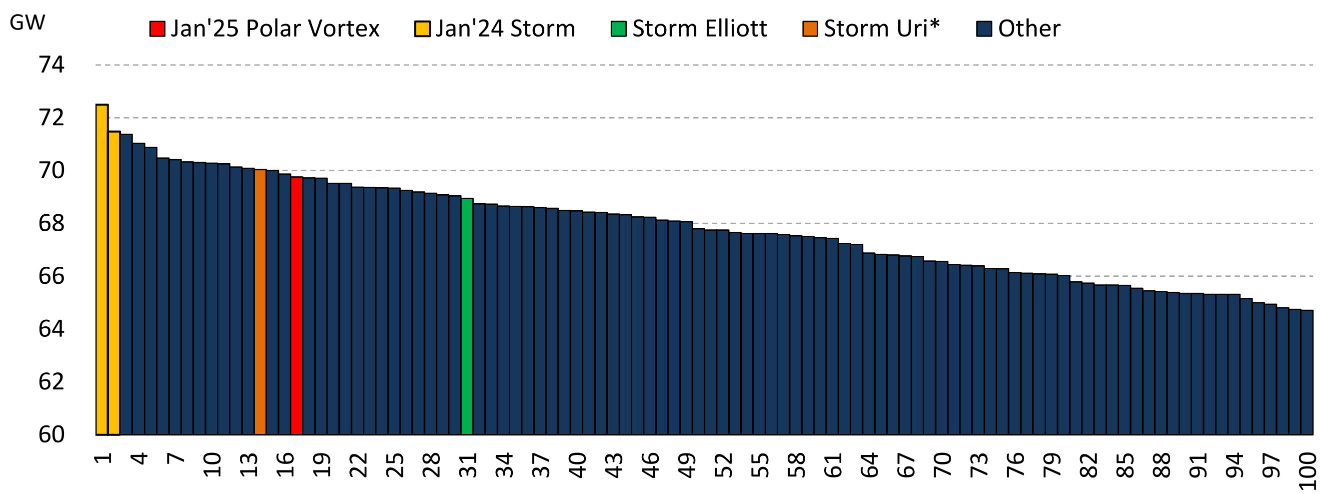
Source: EIA Hourly Grid Monitor & EIA 860 data

ERCOT

The Electric Reliability Council of Texas (ERCOT) is an independent system operator (ISO) that operates exclusively within Texas. It oversees the management of the bulk electric power grid, serving over 26 million Texans, who represent approximately 90% of the state's electric load.

In December 2024, ERCOT averaged a demand of about 46 GW. On January 20, the average daily demand surged to 69.7 GW, peaking at 73.7 GW during the peak hour. However, this demand was still lower than the peaks recorded during the January 2024 Winter Storm, when daily demand averaged 72.5 GW, as shown in **EXHIBIT 13**. Notably, Storm Uri and Storm Elliott registered peak demands of 70 GW and 68.9 GW, respectively.

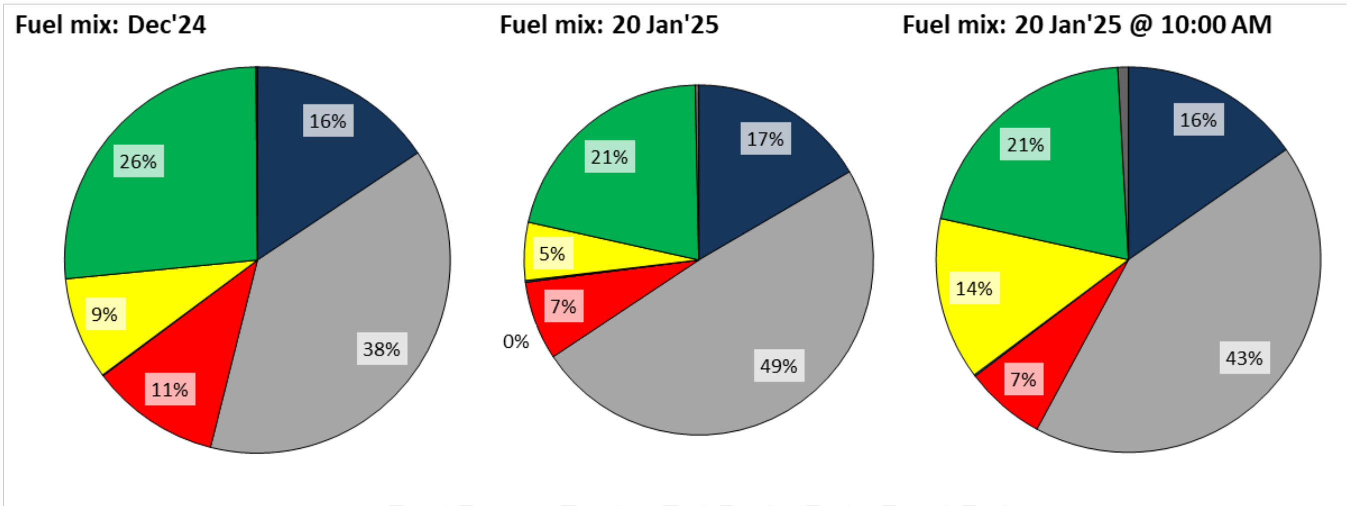
EXHIBIT 13: ERCOT - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor; *Note: forecasted demand for Uri is shown. Widespread power outages caused actual demand to be much lower

Natural gas (38%) and wind (26%) are the largest contributors to the ERCOT generation mix, while coal, nuclear, and solar collectively account for the remaining third. As illustrated in **EXHIBIT 14**, the reduced solar generation during the winter months is due to decreased solar irradiation and snowfall, along with lower-than-average temperatures in January. Consequently, ERCOT was dispatching more coal and natural gas than in the previous month. However, during peak demand hours in the morning of January 20 when sunlight was available, solar generation increased by 6 GW, leading to a rise in the generation mix to 14% despite averaging at 5% for the entire day, as shown in **EXHIBIT 14**.

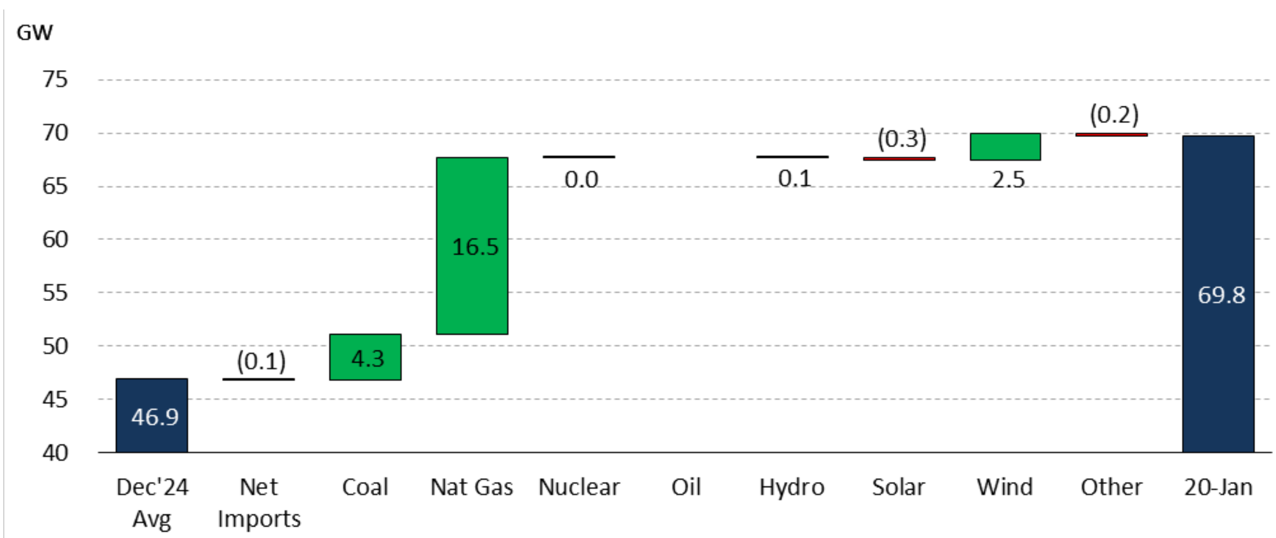
EXHIBIT 14: ERCOT - GENERATION MIX



Source: EIA Hourly Grid Monitor

The following two exhibits, **EXHIBIT 15** and **EXHIBIT 16**, provide a comparative analysis of the demand and generation response of various resource types during the peak demand day and hour of the January 2025 Polar Vortex, compared to the average demand observed in December 2024. On January 20, demand surged by over 20 GW. Consistent with patterns from previous events, such as the January 2024 Winter Storm, natural gas played a key role in meeting this shortfall during the peak demand period, contributing over 72% to the additional demand, as illustrated in **EXHIBIT 15** and **EXHIBIT 16**. Additionally, coal usage was elevated compared to December, as coal plants were operating at higher utilization due to the colder temperatures in the first few weeks of January 2025.

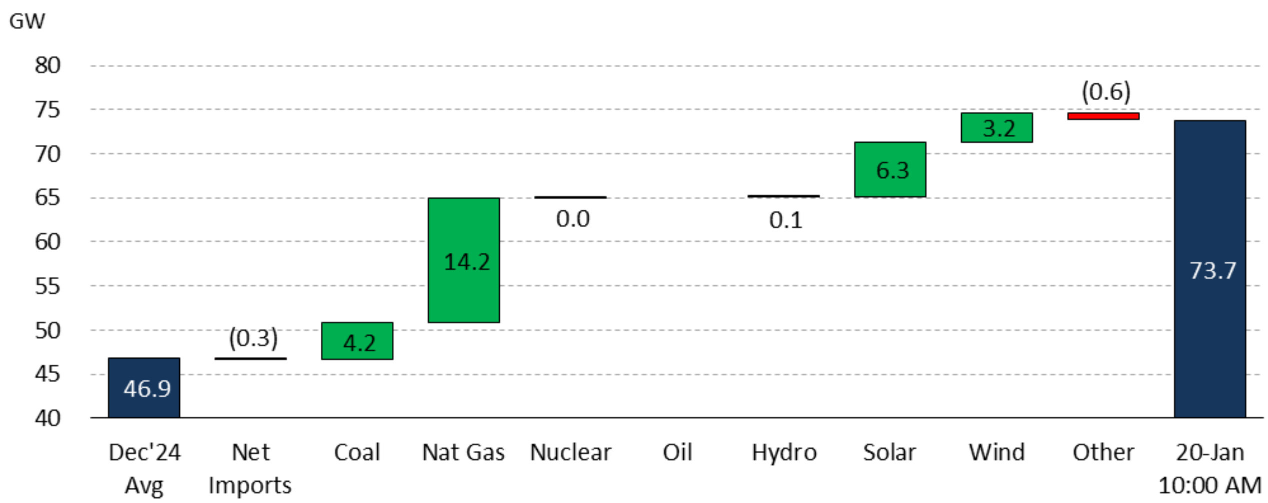
EXHIBIT 15: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the January 2025 Polar Vortex, electricity demand in ERCOT peaked during the morning hours, surpassing the average daily peak demand for that day by nearly 4 GW. Compared to the previous month, peak-hour demand increased by 57%. Since this surge occurred during daylight hours, solar generation contributed an additional 6 GW to the grid relative to the prior month, as shown in **EXHIBIT 16**. Coal and natural gas collectively supplied 18.4 GW of the 27 GW increase in demand, with the remaining additional requirements met by renewable sources.

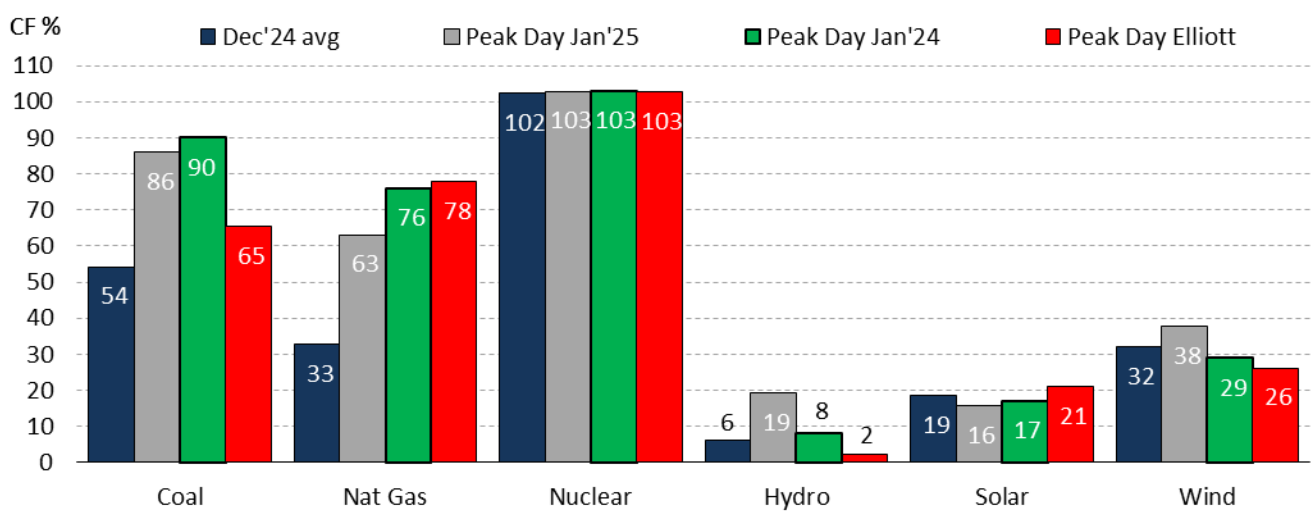
EXHIBIT 16: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 17 illustrates the capacity factors of various generating resources during peak demand periods compared to December 2024 in ERCOT. On the peak day of the January 2025 Polar Vortex, coal and natural gas units operated at average capacity factors of 86% and 63%, respectively—significantly higher than their December 2024 averages of 54% and 33%. Wind generation operated at 38%, exceeding the capacity factors observed during the January 2024 Winter Storm (29%) and Winter Storm Elliott (26%). However, due to its inherent intermittency, wind generation varied significantly depending on time and weather conditions during peak demand hours. The solar capacity factor during the Polar Vortex event decreased slightly from December 2024 due to increased cloud cover during the event.

EXHIBIT 17: ERCOT - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



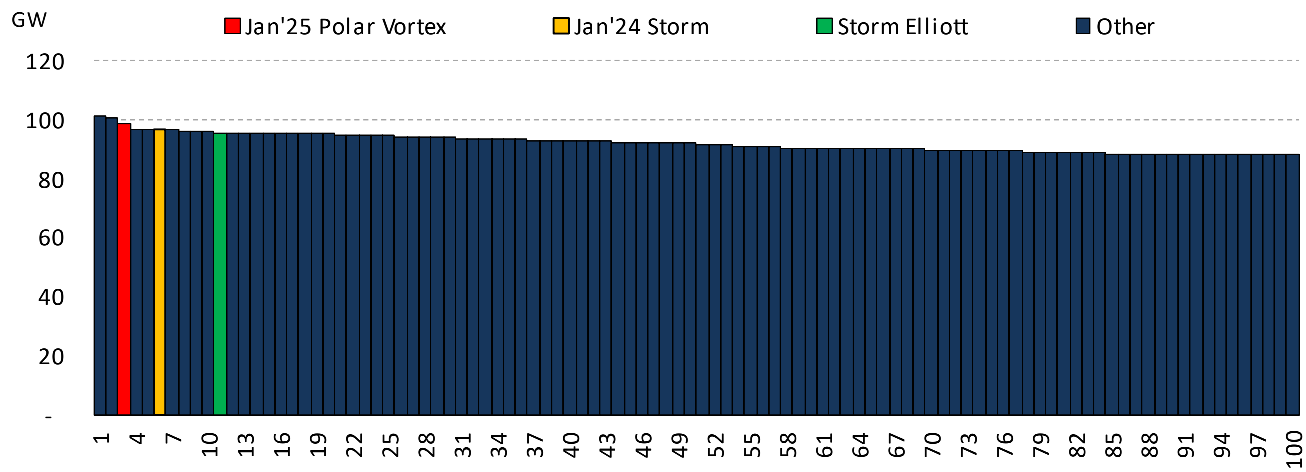
Source: EIA Hourly Grid Monitor & EIA 860 data

MISO

MISO (Midcontinent Independent System Operator) is the second-largest Independent System Operator in the U.S., responsible for managing the flow of electricity across 15 states and serving over 45 million customers.

During the winter weeks of December, the MISO region experienced an average hourly electricity demand of 73.8 GW. The peak demand occurred on January 21, 2025, during the Polar Vortex event, with an average demand of 99 GW and a peak hourly demand of 107.1 GW in the evening. Interestingly, MISO also recorded a similar peak in hourly electricity demand of 106.8 GW during the morning hours of that same day. As shown in **EXHIBIT 18**, this day represents the third-highest demand recorded in the region's history.

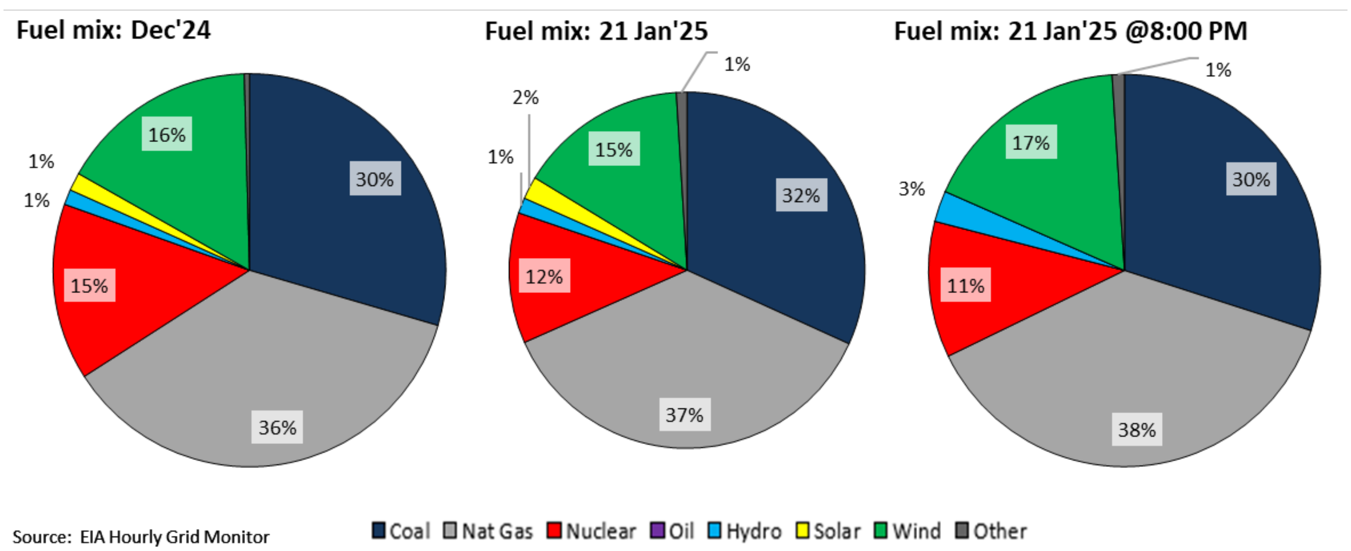
EXHIBIT 18: MISO - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

EXHIBIT 19 illustrates the average generation mix for the MISO region during December 2024, specifically on the peak demand day of the Polar Vortex, which occurred on January 21, 2025, at 8:00 PM. Typically, coal and natural gas constitute the majority of the generation mix, accounting for 66% of the total. Wind generation also plays a significant role as a renewable energy source, though solar and hydro generation contribute only small amounts. Notably, the distribution of the generation mix remained largely unchanged during this time of critical demand on January 21, indicating that the generation of natural gas, coal, and wind was proportionately heightened. Since peak demand occurred in the evening after sunset, the contribution from solar was negligible.

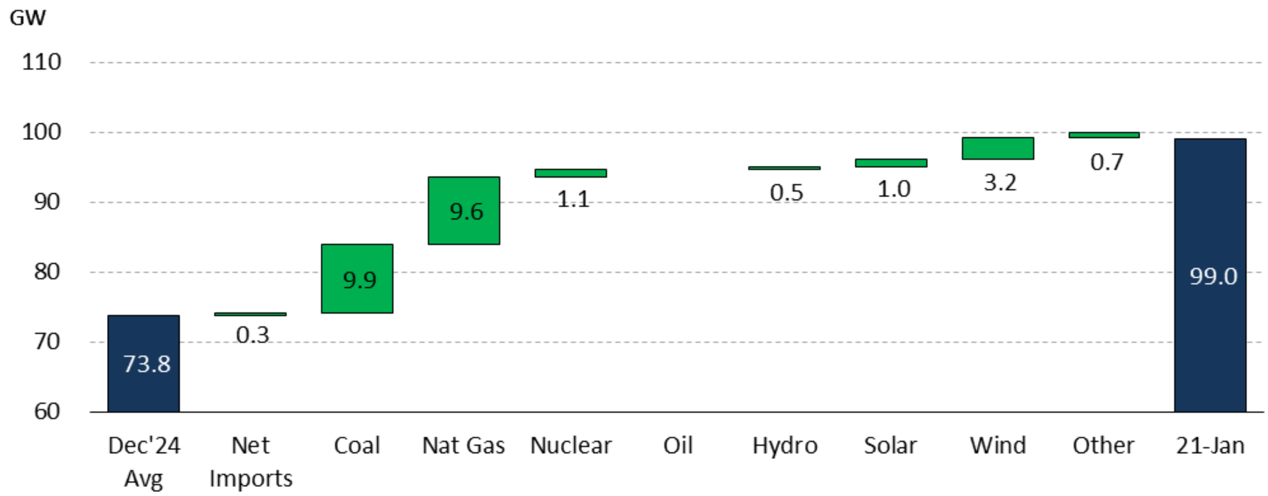
EXHIBIT 19: MISO - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 20 compares the generation profiles between the average demand during the winter weeks of December 2024 and the peak demand day during the Polar Vortex in January 2025. On January 21, the average demand reached 99 GW, which was around 25 GW higher than the December 2024 average of 73.8 GW. As a result of the colder temperatures, coal-fired units were already generating a daily average of nearly 27.8 GW in January, compared to an average of 21.9 GW in December 2024. In response to the increased load on January 21, coal generation rose by an additional 4 GW, bringing it to 31.8 GW. Similarly, natural gas generation increased from 27 GW in December 2024 to 36.6 GW on January 21, marking a 35% increase.

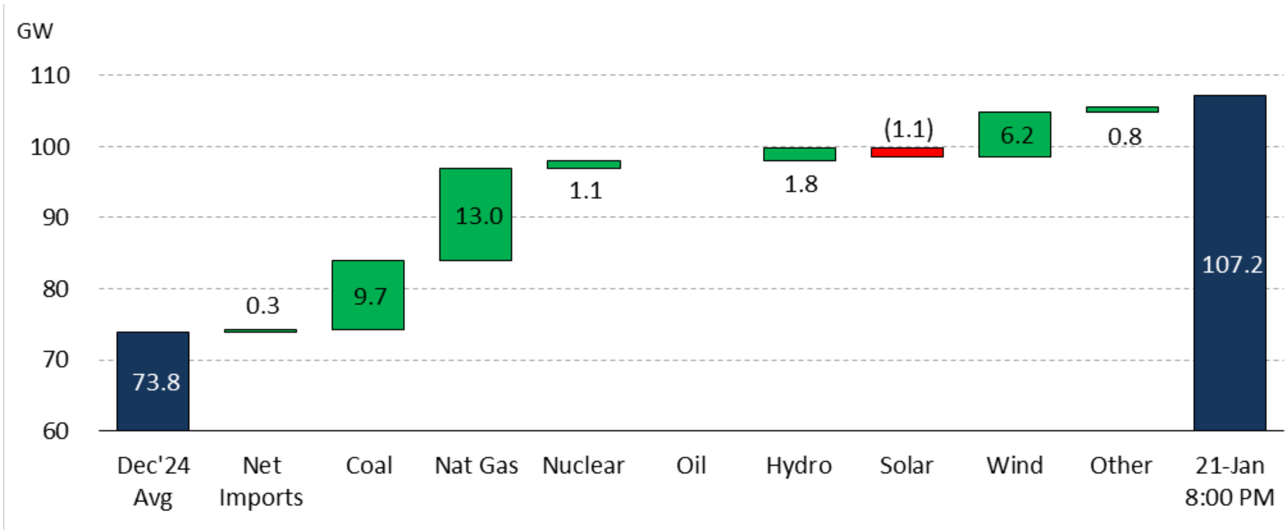
EXHIBIT 20: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

EXHIBIT 21 compares the generation mix between the average demand in December 2024 and the peak hour of the highest demand experienced during the January 2025 Polar Vortex. This peak reached 107.2 GW, making it one of the highest demand peaks in MISO's history. Notably, MISO recorded two comparable periods of peak demand on January 21: in the morning at 10 AM, the demand peaked at 106.8 GW, and in the evening at 8.00 pm, it reached about 107.2 GW. The availability of solar and wind generation during these times significantly influenced the amount of coal and natural gas dispatched. In the morning, wind generation was approximately 12 GW, solar generation was 2.5 GW, natural gas generation amounted to 41 GW, and coal generation to 33 GW. In contrast, during the evening hours—when demand was slightly higher due to increased sustained winds—wind generation averaged around 18.4 GW. During this time, natural gas and coal generation were slightly lower, at 40 GW and 31.7 GW, respectively. This scenario highlights the flexibility of dispatchable resources like natural gas and coal. For instance, natural gas generation varied from 31 GW during peak solar generation hours to 42 GW at other times of the day.

EXHIBIT 21: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

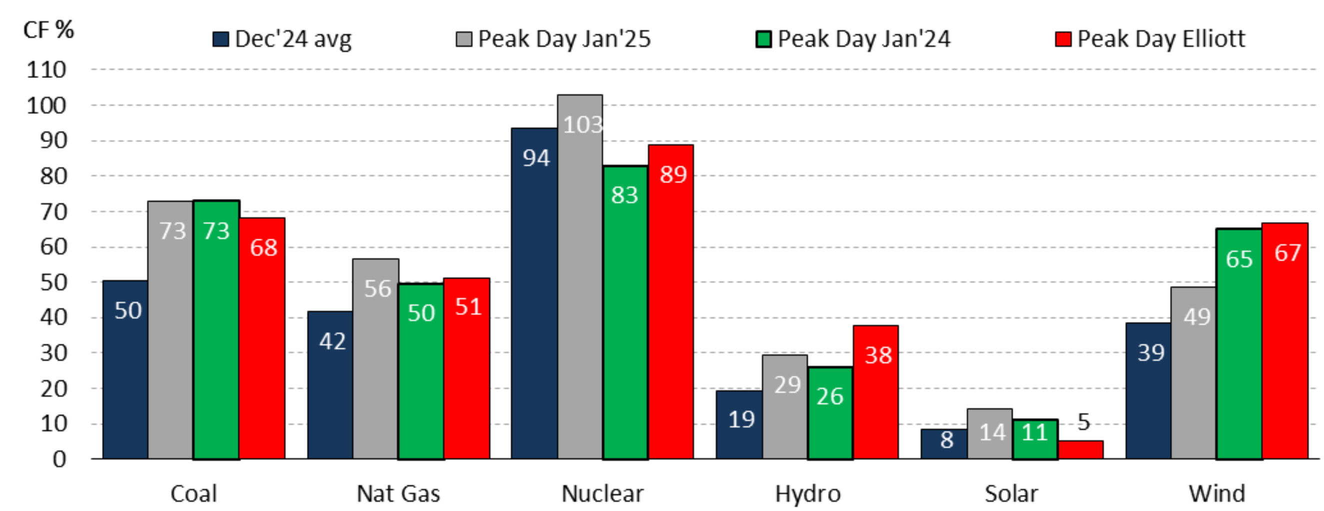


Source: EIA Hourly Grid Monitor

EXHIBIT 22 compares the capacity factors of various electricity generation resources during peak demand periods in January 2025 to those observed in December 2024, specifically referencing January 21 in the MISO region. During the Polar Vortex event, both coal and natural gas showed significantly higher capacity factors, recording 73% and 56%, respectively. In contrast, their capacity factors in December 2024 were only 50% and 42%. It is noteworthy that coal was already operating at 63.1% in January prior to this extreme weather event, which is 13 percentage points higher than in December 2024.

On January 21, 2025, favorable weather conditions contributed to higher wind capacity factors. On that day, average wind generation reached 15.4 GW, peaking at 18.4 GW during the hour of highest electricity demand. This is an increase compared to December 2024, when the average wind generation for the month was only 12.2 GW. In past events, such as Winter Storm Elliott, sustained strong winds have allowed wind resources to achieve capacity factors exceeding 65%. This highlights how varying weather conditions significantly affect the availability of wind generation. While the solar capacity factor increased to 14% on January 21 in comparison to 8% in December, the number remains low on average due to colder weather and low solar irradiation during winter.

EXHIBIT 22: MISO - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data

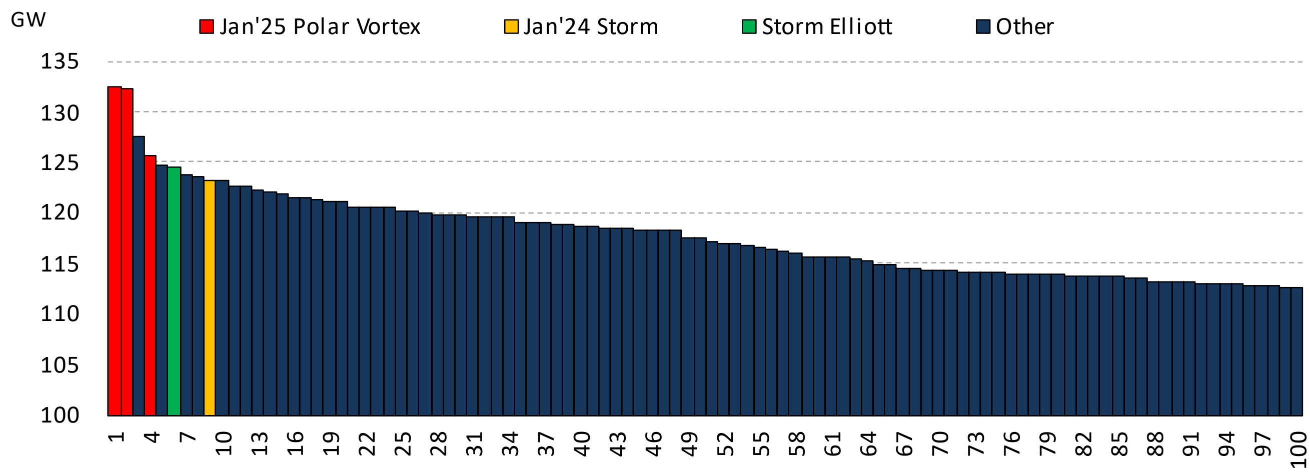
PJM

The PJM Interconnection, the largest Independent System Operator (ISO) in the nation by capacity, serves approximately 65 million customers across 13 states and the District of Columbia. During the winter, PJM typically experiences an average hourly demand of approximately 95-98 GW.

The January 2025 Polar Vortex set new records for electricity demand in the PJM region, with peak demand exceeding 132 GW, marking the highest and second-highest demand days on record, as shown in

EXHIBIT 23. This exceeded all previous extreme weather events, with Storm Elliott closely following, reaching a peak demand of 124 GW. This was slightly below the levels observed during the Jan'25 Polar Vortex, while the January 2024 Winter Storm peaked just 1 GW lower than Storm Elliott.

EXHIBIT 23: PJM - TOP 100 ELECTRICITY DEMAND DAYS

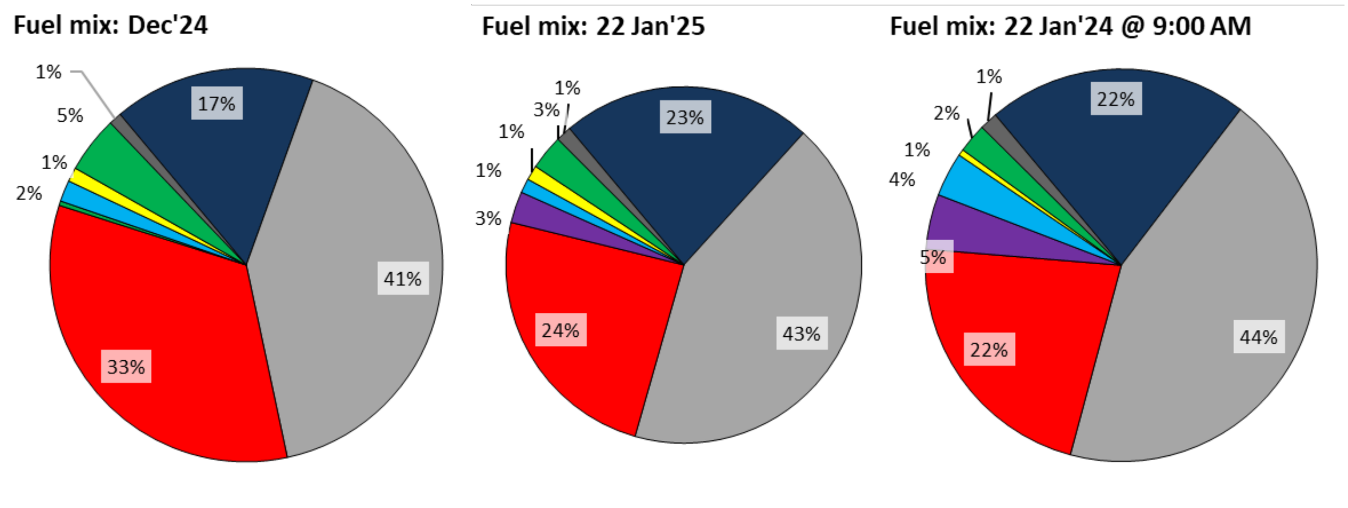


Source: EIA Hourly Grid Monitor

In PJM, nuclear power typically accounts for nearly one-third of total generation capacity. However, during the January 2025 Polar Vortex, the rapid surge in electricity demand led to a notable shift in the fuel mix, as shown in **EXHIBIT 24**. As nuclear power plants typically run at or near-maximum capacity, there was limited opportunity for an increase in generation while other resource types ramped up output, leading to a decline in nuclear power's generation mix share. Coal generation saw a significant increase, contributing just under 25% of the fuel mix on the peak demand day, approximately 6 percentage points higher than its share in December 2024. Similarly, natural gas generation increased, maintaining a relatively consistent share of the fuel mix compared to normal winter conditions. Oil generation, which was negligible in the previous month, ramped up significantly to help meet the heightened demand.

During the peak hour of the winter storm, multiple fuel sources were mobilized to sustain grid reliability. Given that peak demand occurred in the morning, contributions from solar and wind declined compared to their December 2024 shares. Conversely, hydro generation increased during the peak hour, providing critical response support. Overall, fossil fuel resources supplied more than 70% of total generation.

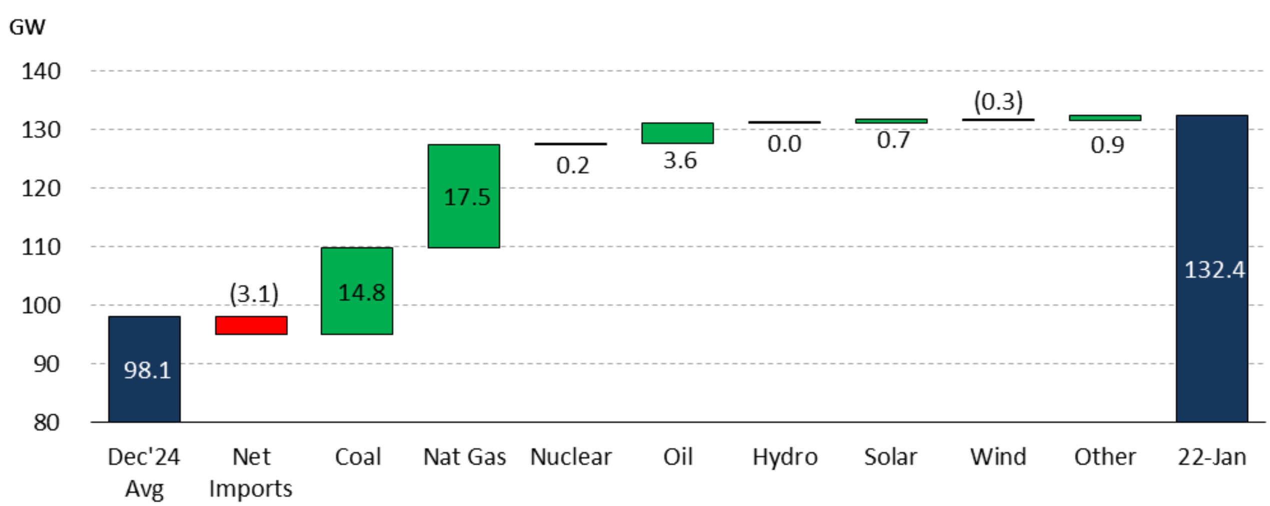
EXHIBIT 24: PJM - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 25 compares the demand and average hourly generation across different fuel technologies between December 2024 and the peak day of the January 2025 Polar Vortex in PJM that occurred on January 22. Notably, a substantial demand disparity of 34 GW was observed between these two periods. Given the robust available generating capacity in PJM during this peak demand period, PJM demonstrated its resilience by exporting an additional 3 GW on an hourly basis to neighboring regions, primarily the Southeast, thereby bolstering their reliability. In response to the heightened demand, fossil fuels witnessed an approximate 60% increase in generation, with coal and gas generating 15 GW and 17.5 GW higher outputs, respectively, compared to the previous winter month. Additionally, wind and solar resources combined contributed only around 1% of the increased demand to the overall demand-supply equation.

EXHIBIT 25: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



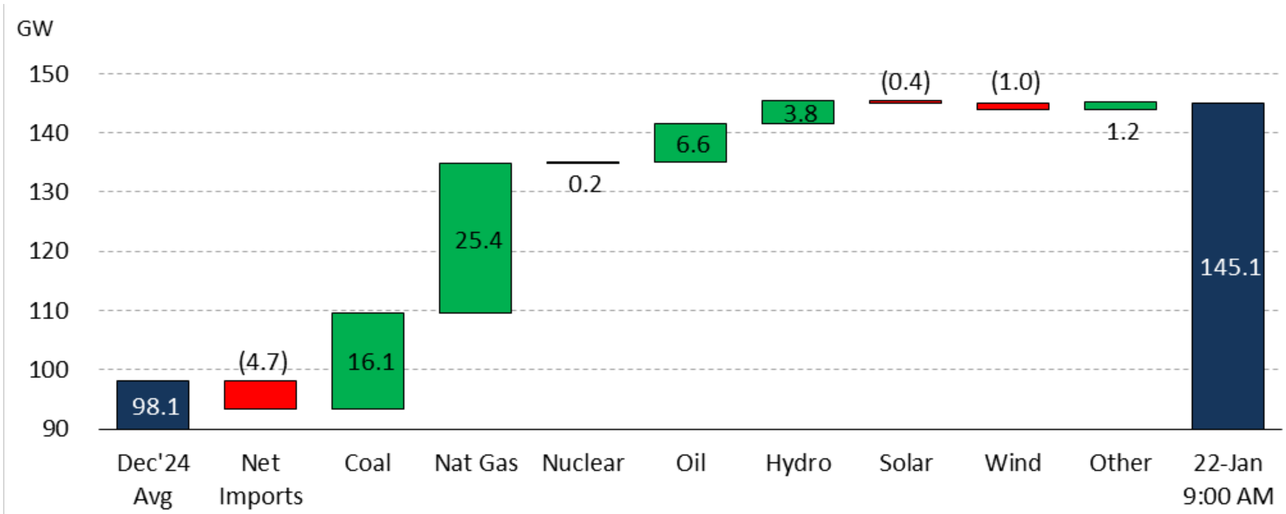
Source: EIA Hourly Grid Monitor

EXHIBIT 26, provided below, offers a detailed comparative examination of the average hourly generation across different fuel technologies between the previous winter month (Dec'24) and the peak hour of the January 2025 Polar Vortex within the PJM region. Notably, the peak hour demand surged to nearly 145 GW, prompting PJM to generate approximately 153

GW to meet this heightened demand and export surplus energy to support neighboring regions, primarily the Northeast and Southeast power market regions.

During this critical hour, coal generation reached approximately 33 GW, doubling its average generation from the previous month, which stood at 17 GW. Natural gas also ramped up production, generating 25 GW more than in the prior winter month to help meet the increased demand. Additionally, oil contributed nearly 7 GW, while combined solar and wind generation declined approximately 1.5 GW compared to the previous month's average. This reduction was primarily due to lower solar radiation and sustained winds due to the weather conditions during the morning hours, limiting their availability during this critical period.

EXHIBIT 26: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 27 presents the capacity factors of various generating resources during periods of peak demand compared to December 2024 demand in PJM. As observed in other regions, the capacity factors of PJM coal units surged significantly, reaching nearly 86% during the peak demand day of the January 2025 Polar Vortex. Natural gas-fired power plants in PJM also demonstrated increased generation compared to the previous month and past winter storm events. In contrast, wind generation declined relative to both the prior month and previous winter storms. The January 2024 winter storm, as well as Winter Storm Elliott, benefited from strong wind generation, achieving a capacity factor of 60% or more. However, during the January 2025 Polar Vortex, the wind capacity factor dropped to 38%. Meanwhile, solar plants operated at a higher capacity factor as the peak demand day experienced increased sunshine, providing some relief compared to the previous month's average generation. Conversely, during Storm Elliott, solar generation was lower due to extensive cloud cover, which significantly limited solar output.

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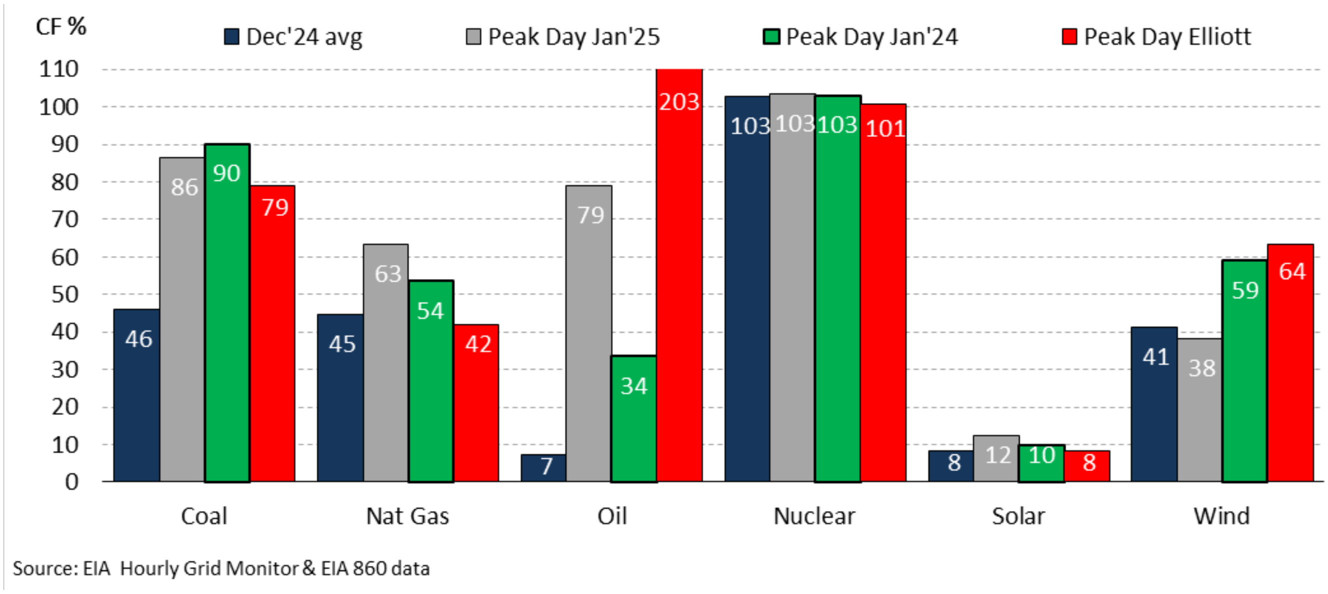
EXHIBIT 27: PJM - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES [3]



Southeast

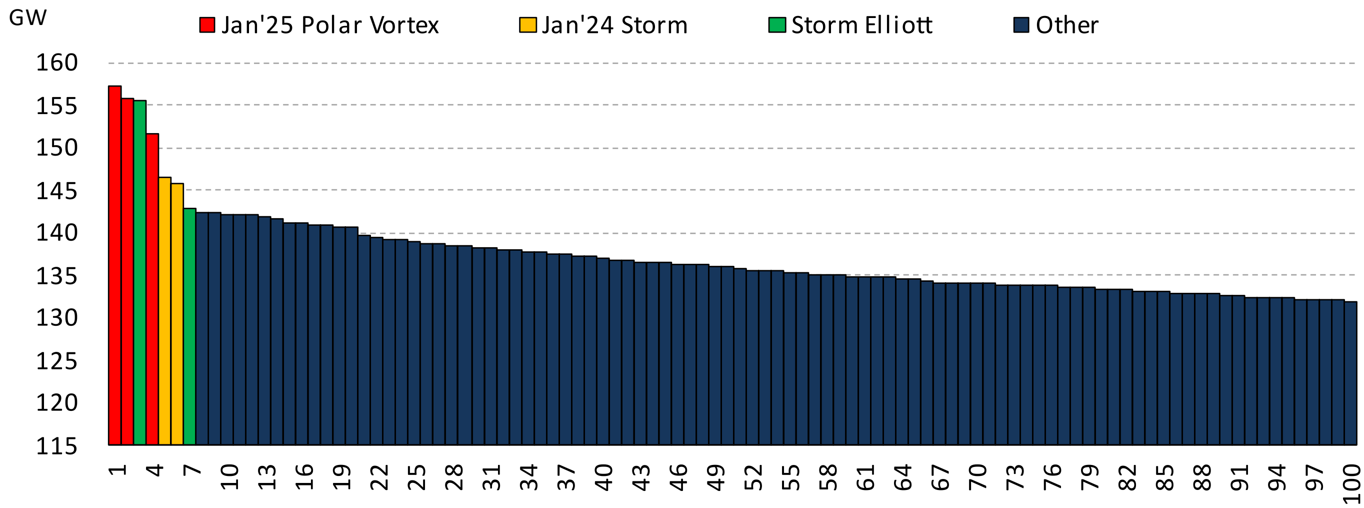
The Southeast region includes most of the states of North & South Carolina, Georgia, Florida, Alabama, Tennessee, Kentucky, and Mississippi and its major utilities, including Duke Energy, Southern Company, Dominion South Carolina, Florida Power & Light, and Tennessee Valley Authority (TVA).

The Southeast region typically experiences an average winter demand of 100–105 GW. However, extreme weather events have driven demand surges of nearly 50% beyond this baseline. Notably, the January 2025 Polar Vortex set a new record, surpassing Storm Elliott and securing three of the top five highest demand days, with peak demand reaching 157 GW, nearly 2 GW higher than the peak demand recorded during Storm Elliott, which ranks as the third highest in the region, as

[3] During this period of heightened demand, some natural gas plants used oil as a backup fuel for power generation. However, these units are not classified as oil-only capacity. As a result, the recorded oil generation exceeded the reported oil-only capacity, leading to a capacity factor of 203%.

shown in **EXHIBIT 28**. The January 2024 winter storm follows in fifth place with a peak demand of 147 GW. Overall, seven of the Southeast region's top ten highest-demand days are attributed to these three extreme weather events.

EXHIBIT 28: SOUTHEAST - TOP 100 ELECTRICITY DEMAND DAYS

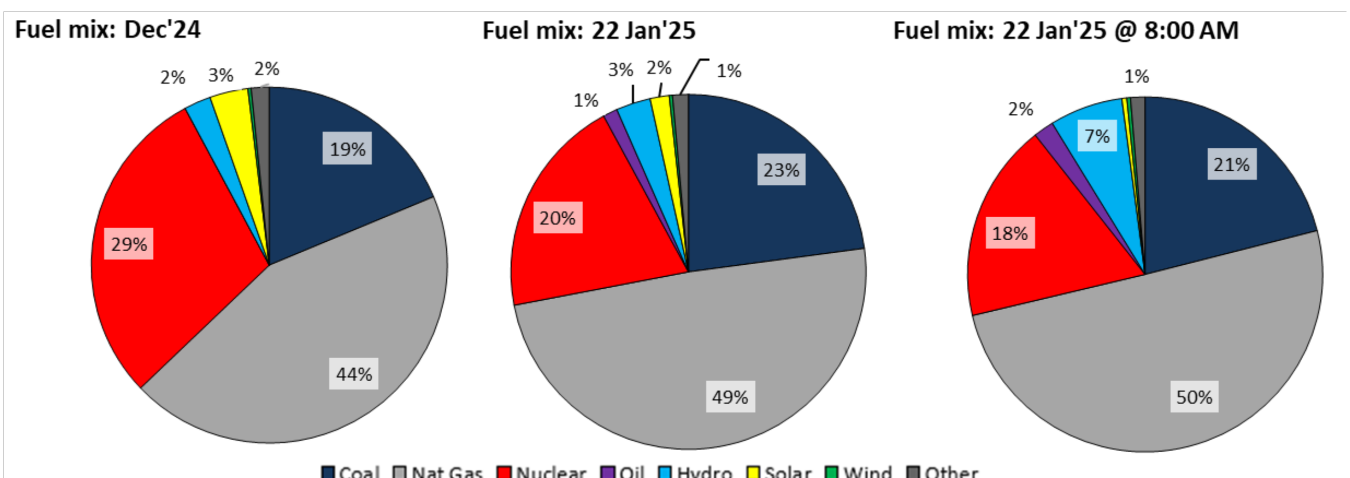


Source: EIA Hourly Grid Monitor

The Southeast region primarily relies on natural gas and nuclear power for electricity generation. During the storm, nuclear generation remained steady, leading to a decrease in its share of the generation mix. In contrast, natural gas and coal generation increased significantly compared to typical winter conditions, as shown in **EXHIBIT 29**. In December 2024, fossil fuel generation accounted for just over 60% of the total supply. However, during the peak demand day of the January 2025 Polar Vortex, fossil fuel contributions rose to 73%, with natural gas alone supplying approximately 50% of total generation.

During the peak hour of the January 2025 Polar Vortex, which occurred in the early morning, wind and solar generation contributed a negligible ~0.5% combined towards the fuel mix. However, hydro generation ramped up substantially, compensating for the decline in renewable output. Additionally, oil-fired generation, which was absent during the previous month, accounted for 2% of the generation mix.

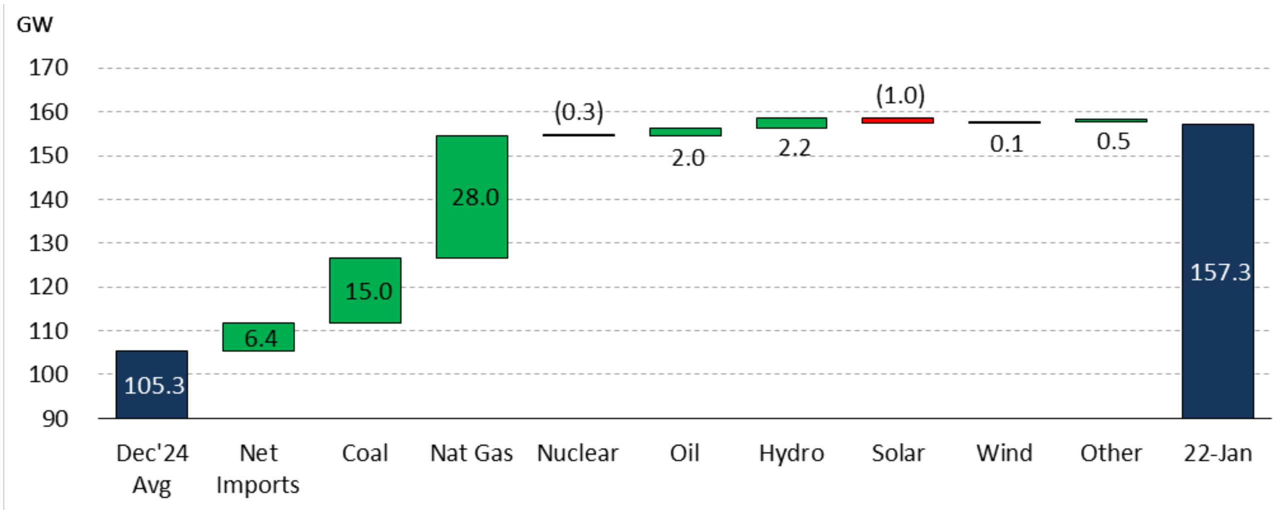
EXHIBIT 29: SOUTHEAST - GENERATION MIX



Source: EIA Hourly Grid Monitor

As hourly demand surged from 105.3 GW in December 2024 to 157.3 GW on January 22 during the Polar Vortex, coal generation played a critical role in bridging the supply gap, increasing by 15 GW—a 77% rise compared to the previous month's average generation. Natural gas generation also ramped up significantly, adding 28 GW beyond the levels observed in the prior winter month, as shown in **EXHIBIT 30**. Additionally, net imports contributed to meeting the heightened demand, supplying an extra 6.4 GW compared to the previous month's supply. While combined wind and solar generation experienced a slight decline, hydro generation increased by 2.2 GW compared to the previous month.

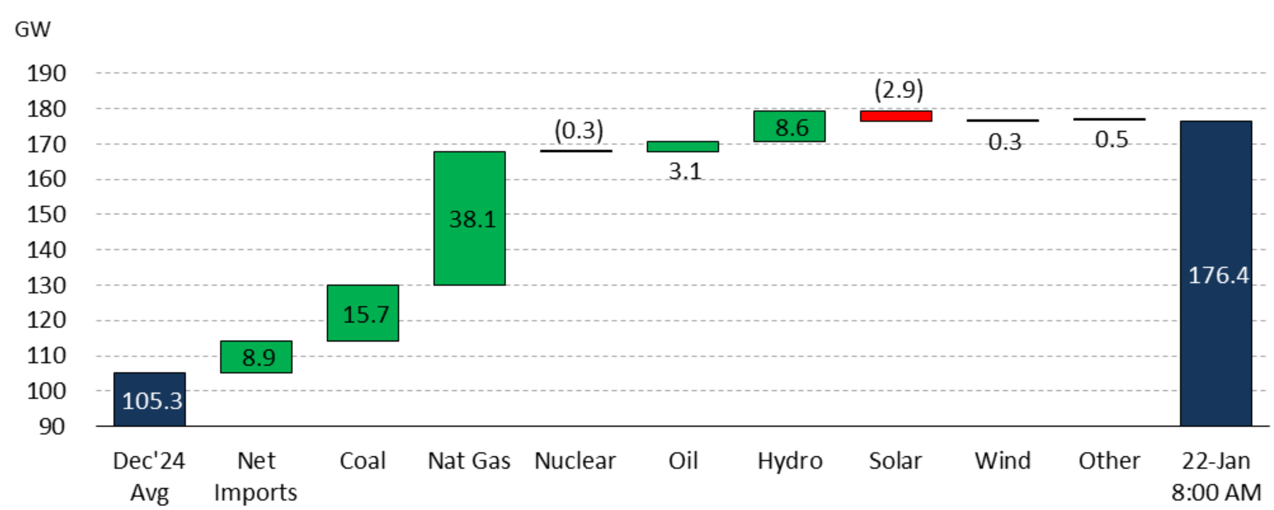
EXHIBIT 30: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the peak demand hour, demand surged to approximately 177 GW, a significant deviation from the average demand of around 105 GW the previous month, as shown in **EXHIBIT 31**. To meet this shortfall, natural gas played a crucial role, adding 38.1 GW, an 82% increase over the previous month's generation—bringing its total output to 84 GW. Coal generation also ramped up, increasing by 15.7 GW to reach a total of 35 GW. Additionally, imports rose sharply, contributing nearly 9 GW. While solar and wind combined generation was minimal at just 1 MW—3 GW lower than the previous month's levels, hydropower played a key role in meeting demand, supplying an additional 8.6 GW to help offset the unprecedented peak.

EXHIBIT 31: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

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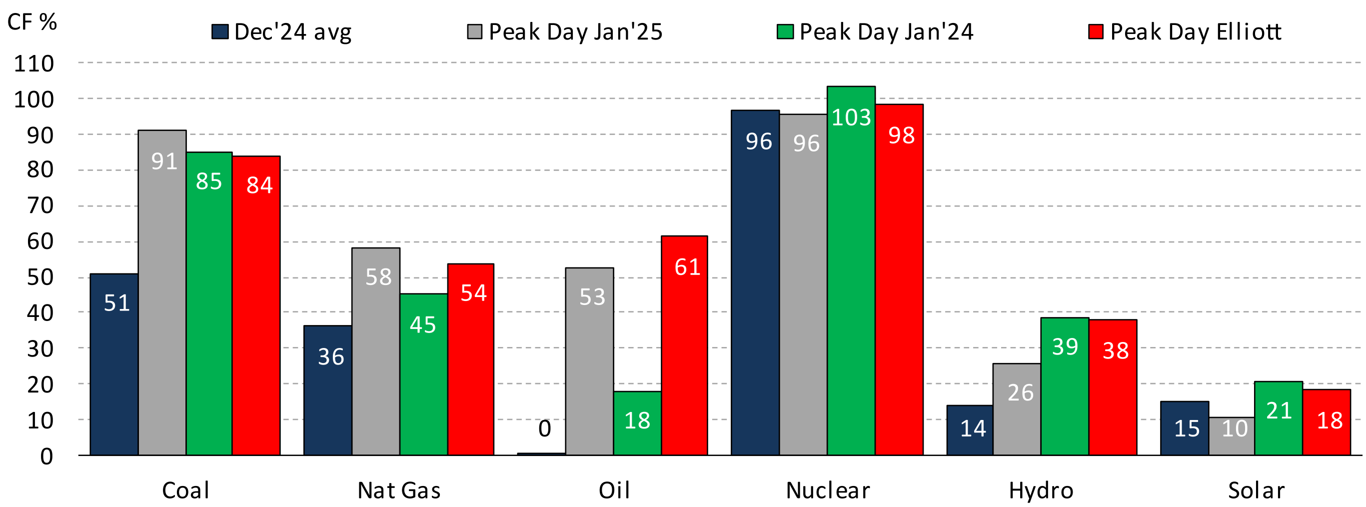
EXHIBIT 32 illustrates the capacity factors of various generating resources during peak demand periods compared to the average generation in December 2024 in the Southeast. Coal-fired power plants exhibited the most significant increase during the peak of the January 2025 Polar Vortex, reaching a record-high capacity factor of 91%, a 40% increase compared to the previous month's average generation. Similar spikes in capacity factors were observed for both coal and natural gas generation across all extreme weather events.

Wind is not a predominant resource in the Southeast, with a total installed capacity of under 1 GW. However, solar capacity has been expanding rapidly, with approximately 9 GW added between Storm Elliott and the January 2025 Polar Vortex, bringing total solar capacity in the region to around 25 GW.

During the January 2024 winter storm, the solar fleet operated at a capacity factor of 32%, whereas during the January 2025 Polar Vortex, it dropped to just 10%, highlighting the variability and uncertainty associated with weather-dependent generation such as wind and solar.

EXHIBIT 32: SOUTHEAST - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



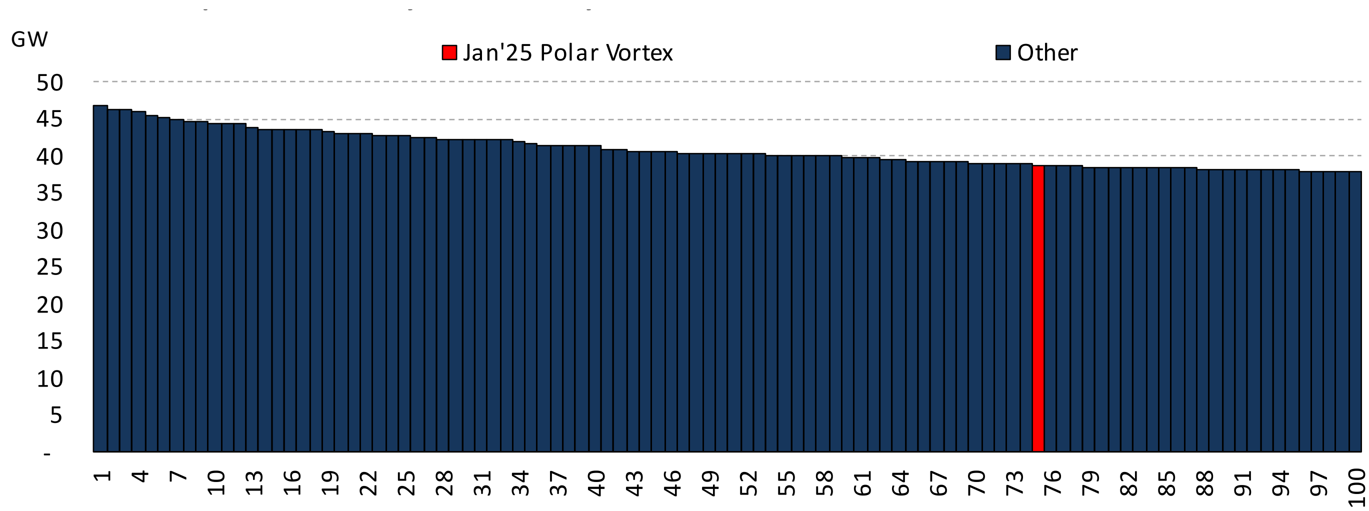
Source: EIA HourlyGrid Monitor & EIA 860 data

Northeast

The Northeast region encompasses most of Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, and New York. Major utilities serving this region include Con Edison, National Grid, and Eversource Energy.

During the winter months, the Northeast typically experiences an average electricity demand of 30–32 GW. However, extreme weather events have occasionally driven demand surges of nearly 50% above this norm. Unlike other regions where extreme weather events have been a primary driver of peak demand, the highest demand days in the Northeast typically occur during the summer months. Nevertheless, the January 2025 Polar Vortex ranked among the top 100 highest-demand days in the region, with electricity demand increasing by nearly 20% compared to the previous month's average and peak-hour demand rising by approximately 35%, as shown in **EXHIBIT 33**.

EXHIBIT 33: NORTHEAST - TOP 100 ELECTRICITY DEMAND DAYS



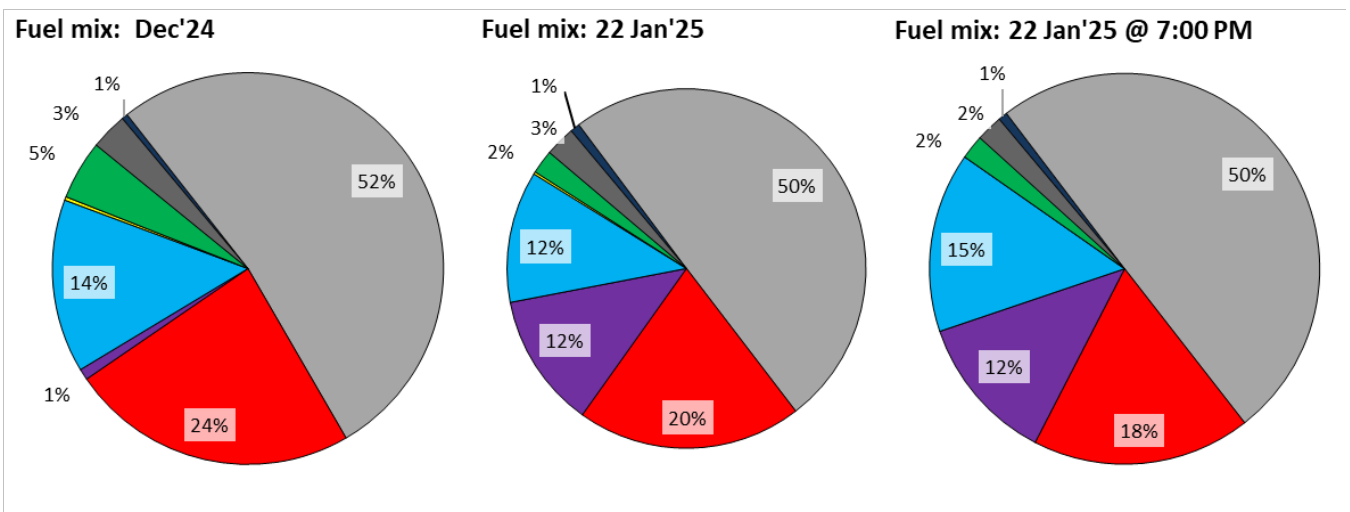
Source: EIA Hourly Grid Monitor

The Northeast region primarily relies on natural gas and nuclear power, which together account for over 75% of total electricity generation. Hydropower and wind contribute approximately 20%, while solar generation remains minimal in the region.

During the January 2025 Polar Vortex, natural gas maintained a steady share in the generation mix, striving to meet the heightened demand. However, with limited coal infrastructure and high natural gas prices, a significant portion of the additional demand was met by oil-fired power plants. Oil, which comprised just 1% of the fuel mix in December 2024, surged to 12% on the peak demand day of the January 2025 Polar Vortex.

During the peak hour of this increased demand, oil and natural gas generation remained central, maintaining a similar fuel mix to the peak demand day. Hydropower contributed 15% to the overall fuel mix during the peak hour, while wind generation declined by 3% compared to the previous month's output.

EXHIBIT 34: NORTHEAST - GENERATION MIX

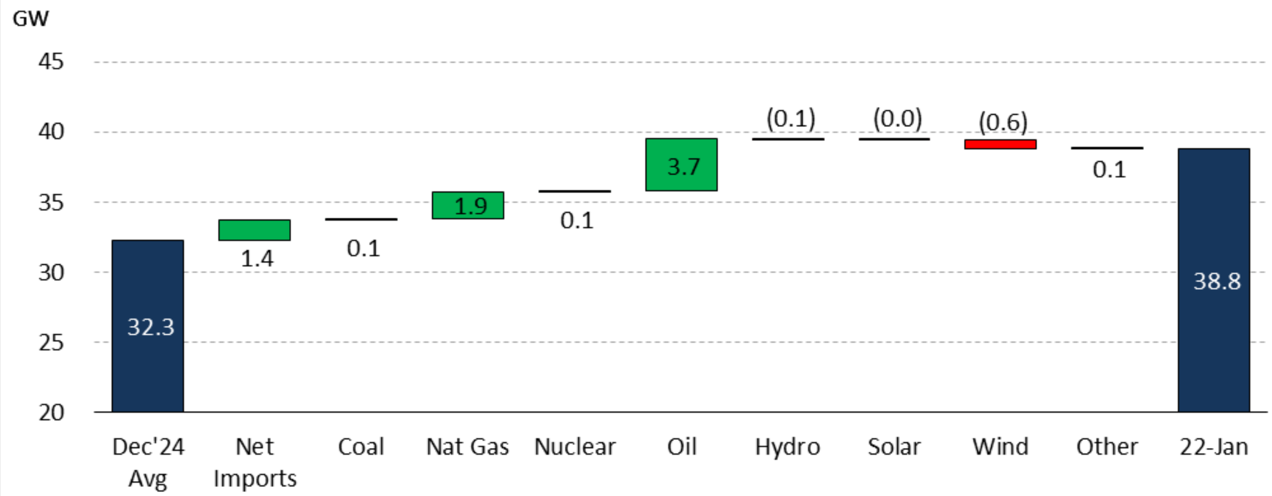


Source: EIA Hourly Grid Monitor

The January 2025 Polar Vortex led to a demand increase of approximately 6.5 GW in the Northeast region compared to the previous month's average. Most of this additional demand—around 70%—was met by natural gas and oil generation.

In contrast, wind generation declined by 0.6 GW compared to the previous month. To address the remaining supply gap, the Northeast imported approximately 1.4 GW of electricity from neighboring regions.

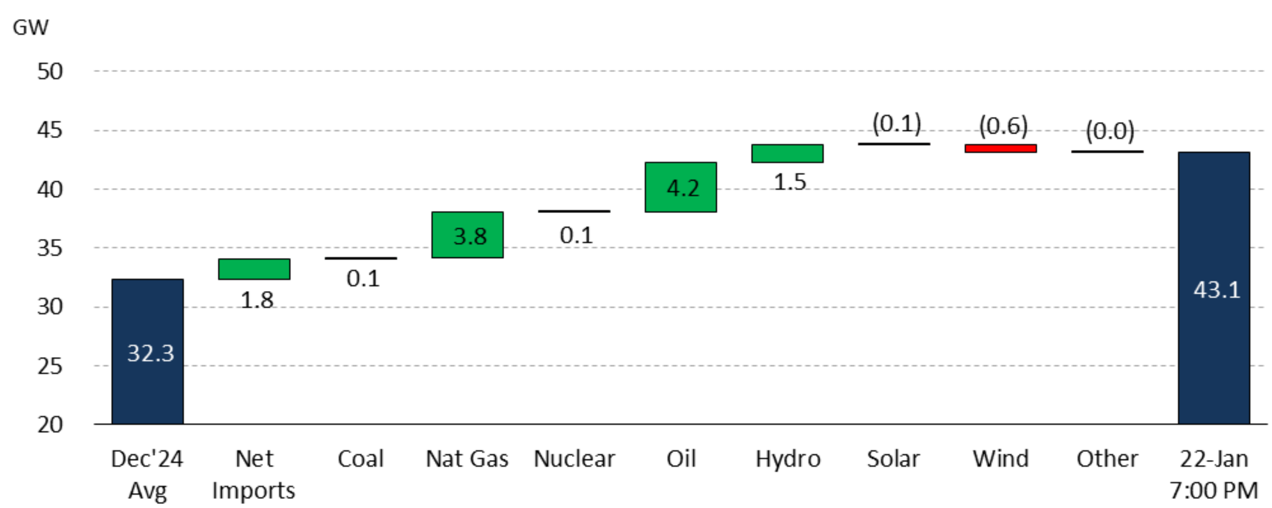
EXHIBIT 35: NORTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the peak demand hour, electricity demand surged to approximately 43 GW, significantly exceeding the average demand of around 32 GW, as shown in **EXHIBIT 36**. To bridge this gap, natural gas and oil generation played a crucial role, contributing an additional 3.8 GW and 4.2 GW, respectively, bringing combined generation to 23 GW. Additionally, hydro generation increased by 1.5 GW, while wind generation declined by 0.6 GW compared to the previous month's levels. Simultaneously, imports rose by nearly 1.8 GW, making a significant contribution to meeting peak demand.

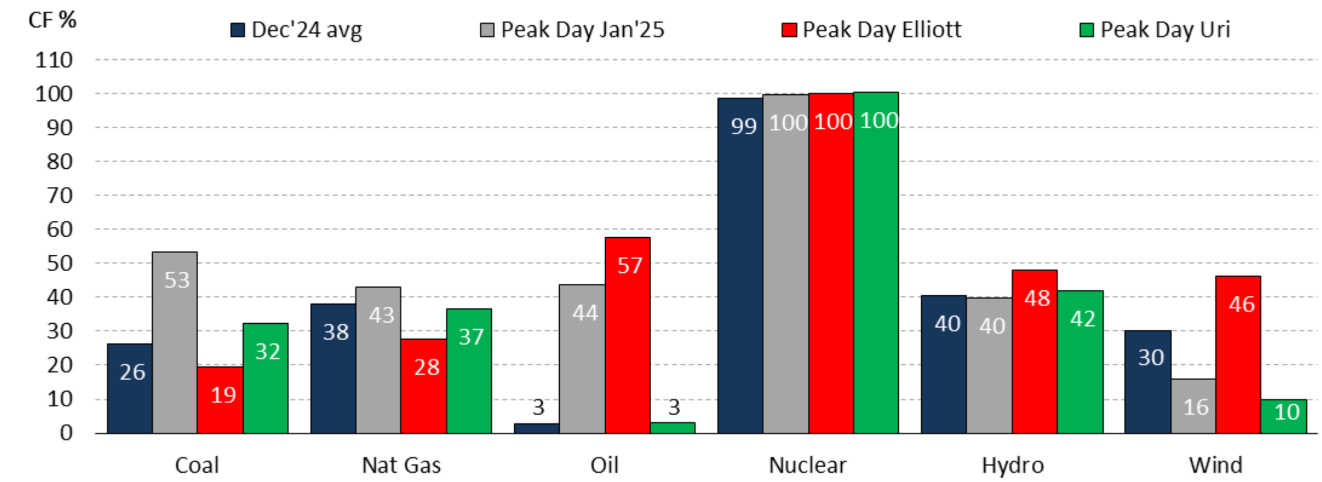
EXHIBIT 36: NORTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 37 illustrates the capacity factors of various generating resources during different peak demand periods compared to the average of December 2024 in the Northeast. Like most regions, natural gas exhibited higher capacity factor utilization during the January 2025 Polar Vortex; however, the trend was different during Storm Elliott. This discrepancy was primarily due to the lack of available natural gas supply, which rendered several gas plants inoperable. Similarly, wind generation has also been inconsistent during these peak extreme weather events, with Storm Elliott reaching a 30% higher capacity factor compared to the Jan'25 Polar Vortex, mainly because Elliott brought a large amount of sustained high winds in the Northeast region that was not observed during the Jan'25 Polar Vortex. Hydro generation remained consistent across all peak demand periods analyzed. Meanwhile, oil-fired generation demonstrated reliability in the region, with the flexibility to ramp up output by approximately 4 to 4.5 GW, catering to almost 12% of the demand.

EXHIBIT 37: NORTHEAST - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES

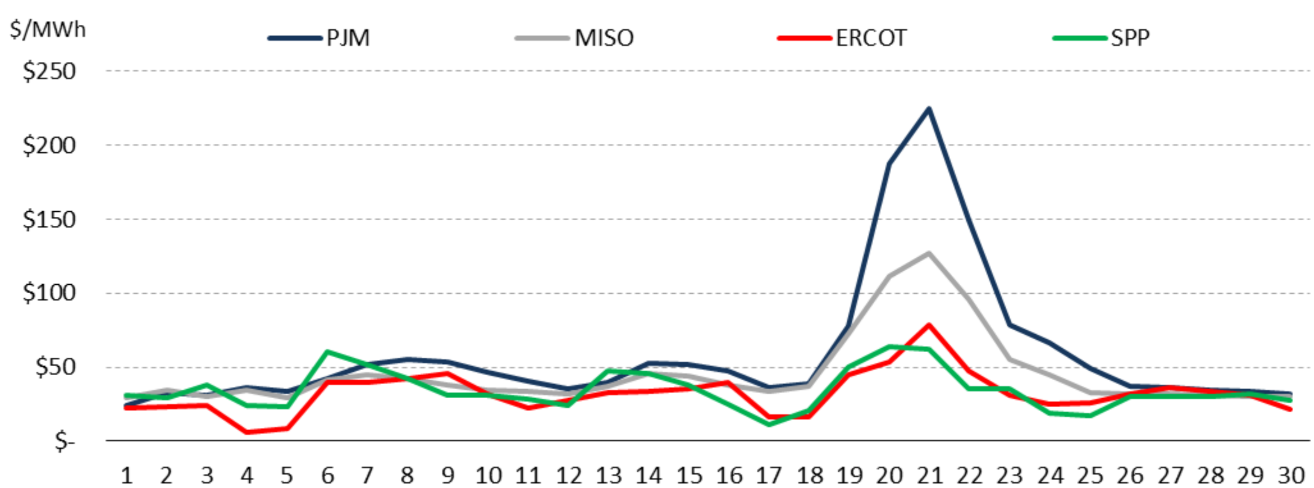


Source: EIA Hourly Grid Monitor & EIA 860 data

PJM Power Price Analysis – Case Study

Besides providing valuable incremental generation during extreme weather events like the January 2025 Polar Vortex, coal-fired power plants also function as a de facto price hedge for regional wholesale and, ultimately, retail power prices. The following section provides a high-level overview of the power price spikes observed across the country during the extreme weather event and the role coal-fired power plants played in limiting these power price spikes.

EXHIBIT 38: DAILY AVERAGE REGIONAL AROUND-THE-CLOCK POWER PRICES DURING JANUARY 2025

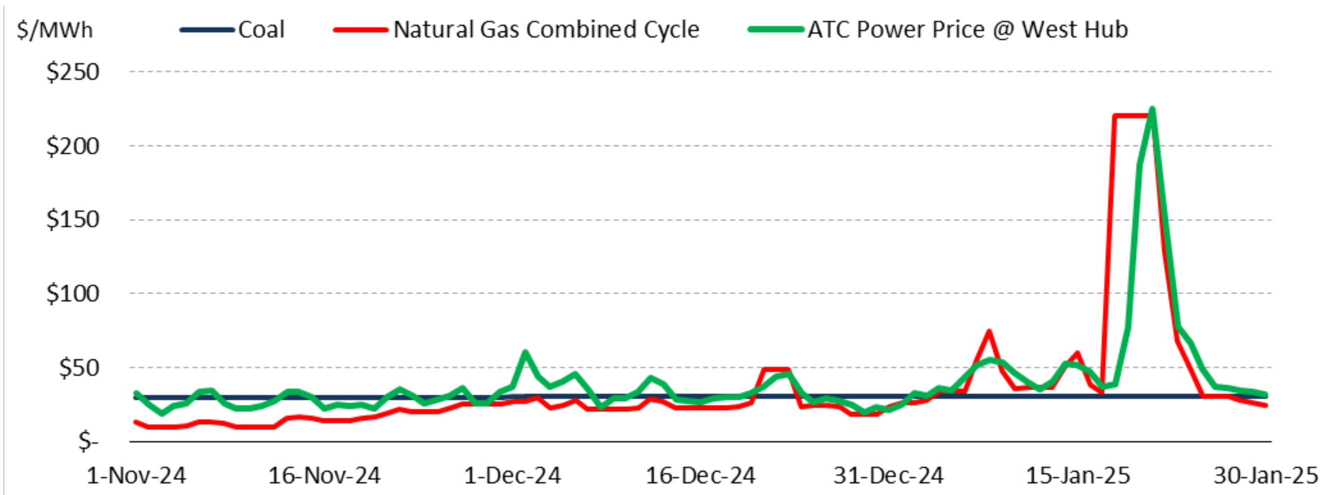


Source: S&P Global

EXHIBIT 38 shows the average daily day-ahead power prices for PJM, MISO, ERCOT, and SPP. As electricity demand increased, so did regional wholesale power prices, which encouraged additional electric generating resources not operating at full capacity yet to increase their generation output. PJM power prices saw the most significant increase of all affected power market regions, where daily average day-ahead power prices spiked to about $225/MWh on January 21 during the peak of the Polar Vortex event. Other power market regions also saw notable increases in their regional power prices.

To review, wholesale power prices are set by the operating cost of the last electric generating resource required to meet the electricity demand of a given hour. Operating costs include fuel costs and other non-fuel variable costs such as reagent costs for emission control equipment, emission allowance costs, or estimated maintenance costs that depend on the number of hours a generating resource operates in a given period. Renewable resources often have the lowest dispatch or operating costs of all electric generating resources since they do not use any fuel or need to budget for any emission allowance or other consumables, limiting their operating costs to estimated variable operating and maintenance costs (VOM). Nuclear plants also have very low variable operating costs compared to their fossil-fuel-based counterparts. Therefore, wholesale power prices are set predominantly by either natural gas, coal, or oil-fired power plants. For fossil-fuel-fired power plants, fuel costs are by far the highest component of their operating cost, often accounting for more than 70% of their total operating or dispatch cost. **EXHIBIT 39** shows the estimated daily dispatch cost for illustrative coal and natural gas combined-cycle power plants in PJM from November 1, 2024, to January 30, 2025.

EXHIBIT 39: ESTIMATED DISPATCH COSTS FOR ILLUSTRATIVE COAL & NATURAL GAS COMBINED CYCLE PLANTS IN PJM

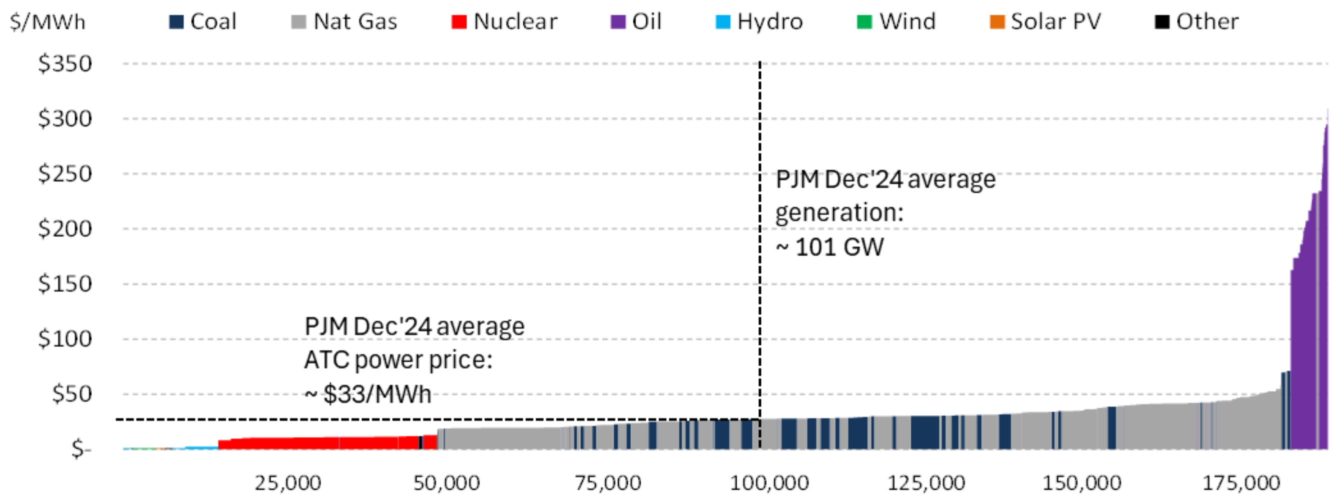


Note: Assumes 10.5 MMBtu/MWh & $4/MWh VOM for coal and 7.5 MMBtu/MWh & $2/MWh for natural gas combined cycle

As shown in **EXHIBIT 39**, there is a notable difference in dispatch cost variability between coal and natural gas power plants. At a high level, plant owners and operators use replacement cost to estimate their fuel costs used in determining their dispatch cost, i.e., what is the current market price for the fuel I am planning to consume during the plant's operation? Due to the absence of a sizeable liquid commodity trading market and the time it takes to produce and transport it, coal market prices show minimal day-to-day variability. Natural gas, on the other hand, is a highly traded energy commodity with possible large swings in market prices depending on short-term supply-demand disruptions and energy commodity trader responses.

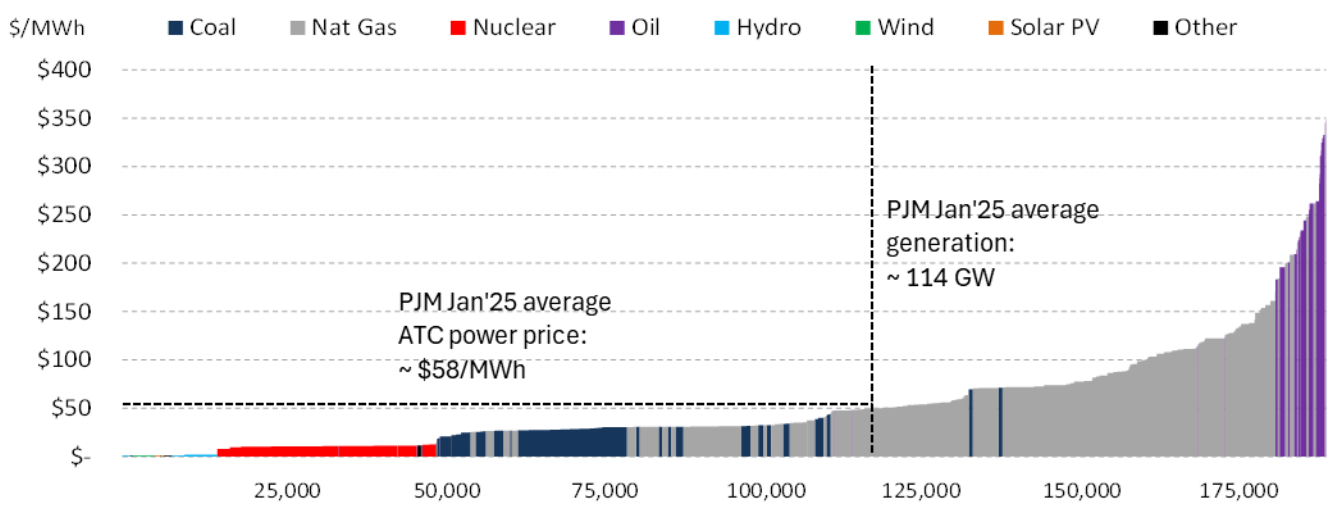
In November 2024, natural gas prices across PJM averaged less than $1.90/MMBtu, compared to coal's $2.50/MMBtu for the same period. As a result, some coal plants across PJM were more often "on the margin," setting regional power prices, while others were not operating at all. For example, capacity factors for the PJM coal fleet averaged less than 30% in November 2024, compared to natural gas' almost 40%. As the temperatures dropped in December 2024 and especially January 2025, natural gas demand for residential and commercial heating began to rise quickly, in addition to rising electricity demand, causing natural gas prices to rise. December 2024 average daily natural gas prices across PJM rose to about $3.25/MMBtu, while average delivered coal prices remained at around $2.50/MMBtu, resulting in increased natural gas-to-coal switching. For example, capacity factors for the PJM natural gas fleet averaged 44.5% in December 2024 compared to the coal fleet's 45.9%. Increasingly, PJM power prices were being set by natural gas-fired power plants instead of their coal-fired counterparts. **EXHIBIT 40** shows the estimated dispatch stack for PJM during December 2024. Notably, coal plants are highlighted in dark blue, natural gas plants in gray, and oil-fired peaking units in purple.

EXHIBIT 40: ESTIMATED PJM DISPATCH STACK DURING DECEMBER 2024



As temperatures continued to drop below the 10-year average for most of January 2025, power and non-power natural gas demand continued to climb, causing natural gas prices to rise in response. Natural gas prices across PJM averaged over $8.50/MMBtu during January 2025, including daily spikes during the peak of the Polar Vortex event to nearly $30/MMBtu. With coal prices nearly flat month-over-month, most PJM coal plants were now more economical to dispatch than their natural gas counterparts. As a result, capacity factors for the PJM coal fleet increased to nearly 70%, while the natural gas fleet showed only a modest increase from their previous month's levels to about 48%. **EXHIBIT 41** shows a notable shift of most coal plants below the dotted marginal cost line during January 2025.

EXHIBIT 41: ESTIMATED PJM DISPATCH STACK DURING JANUARY 2025



Finally, on the peak demand day (January 21, 2025) for the PJM power market during the Polar Vortex event, natural gas prices spiked to nearly $30/MMBtu, resulting in a daily average power price of about $225/MWh. In other words, it cost the PJM power market over $750 million to meet the electricity demand of 3.4 million MWh on January 21, 2025. Most notably shown by **EXHIBIT 42**, oil-fired peaking units were relied on to meet the record demand for electricity across the region and its neighbors.

EXHIBIT 42: ESTIMATED PJM DISPATCH STACK ON JANUARY 21, 2025

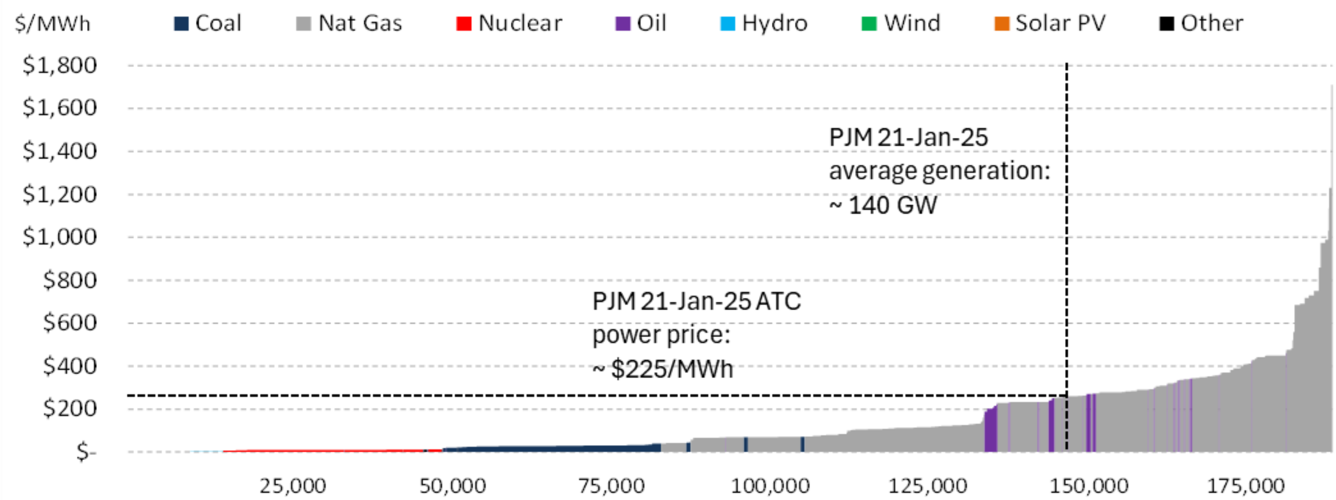
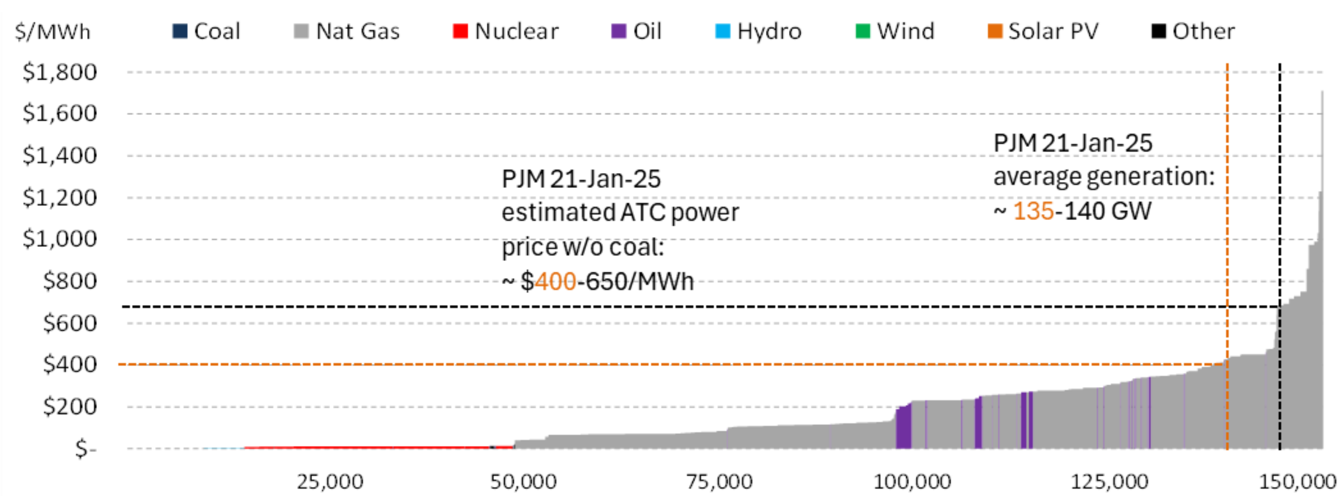


EXHIBIT 43 highlights the dramatic impact existing coal plants have on PJM wholesale power prices. The chart shows a hypothetical PJM dispatch stack on January 21, 2025, with no coal-fired power plants available to generate electricity. As the latest PJM capacity auction has shown, the PJM supply curve has limited surplus resources available to generate electricity during peak electricity demand events such as the January 2025 Polar Vortex. Assuming the same generating resources without coal-fired power plants, PJM's daily average power prices would have increased to over $400/MWh and as high as $650/MWh, more than doubling from their actual values. Accordingly, the resulting increase in power prices would have cost the PJM market an additional $500 million to $1.4 billion in electricity costs, which ultimately would be borne by electricity consumers across PJM's footprint.

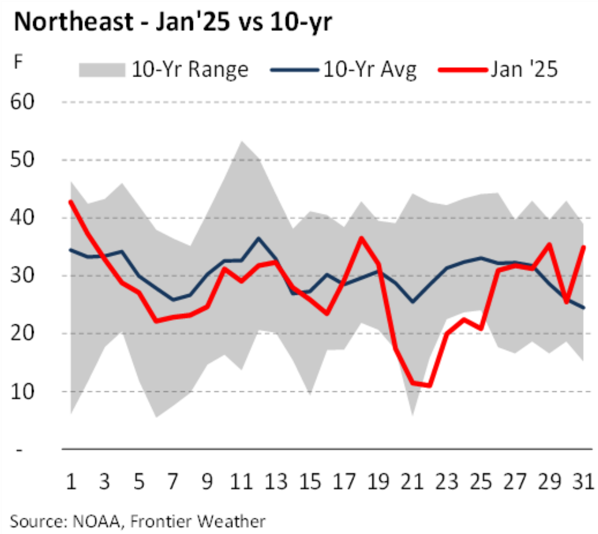
EXHIBIT 43: HYPOTHETICAL PJM DISPATCH STACK ON JANUARY 21, 2025, WITHOUT COAL PLANTS

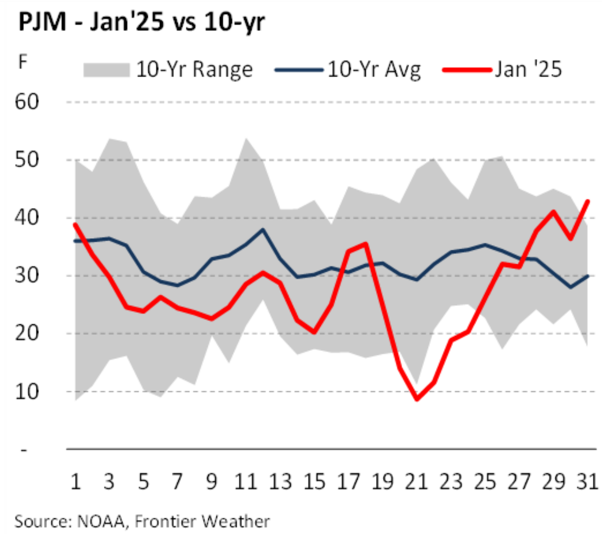


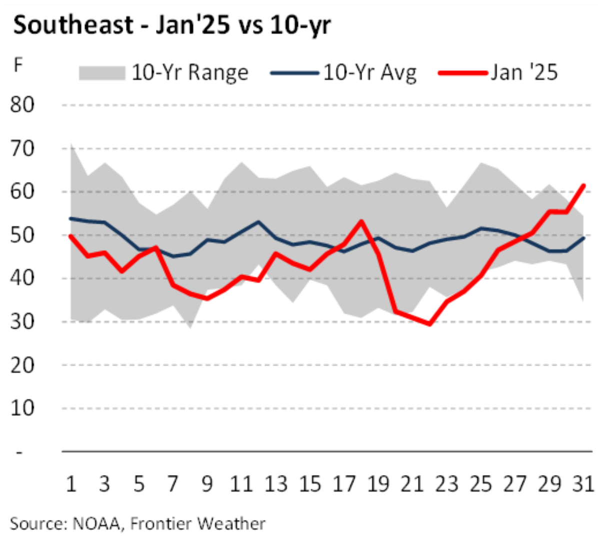
Alarmingly, about one-third of the existing PJM coal fleet is announced to retire before the end of the decade. As this extreme weather event and the others before it have shown, dispatchable, highly reliable generating resources like coal-fired power plants are paramount to ensuring reliable and affordable electricity service to electric consumers across the United States.

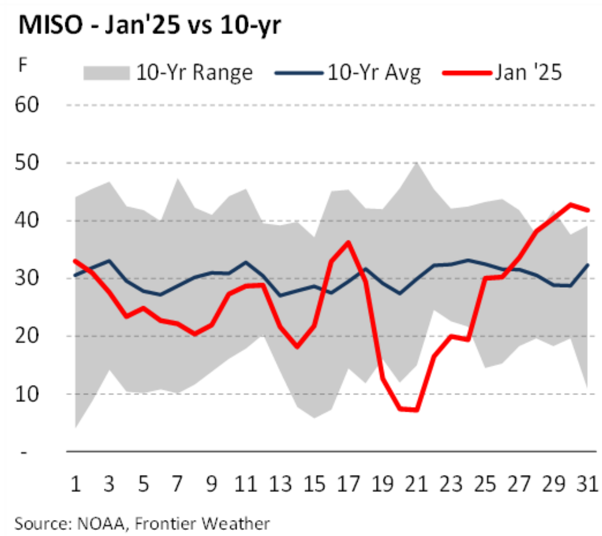
Appendix

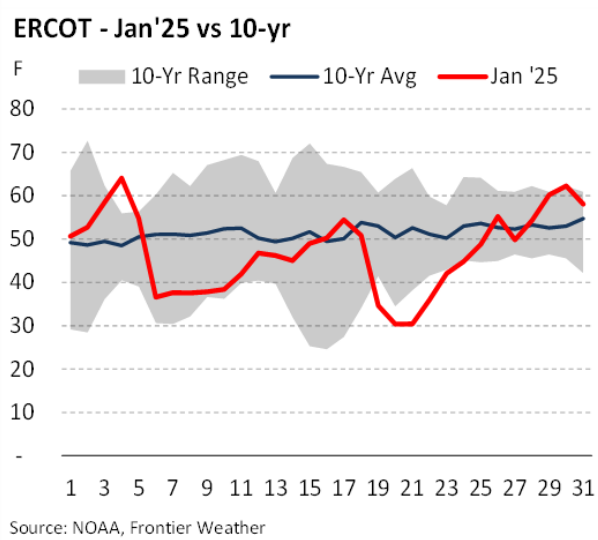
EXHIBIT 44: REGIONAL DAILY TEMPERATURE IN JANUARY 2025 VS 10-YEAR AVERAGE

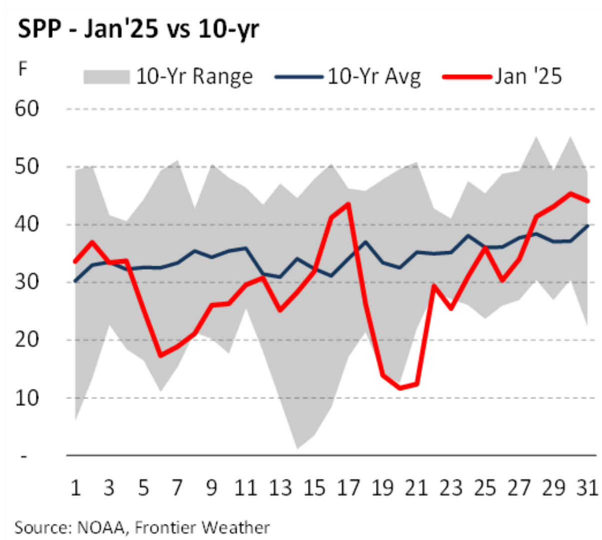












ATTACHMENT C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER25-1357-000

AFFIDAVIT OF SETH SCHWARTZ

1. My name is Seth Schwartz. I am Managing Director of Energy Ventures Analysis ("EVA"). My business address is 8045 Leesburg Pike, Suite 200, Vienna, VA 22182-2760. On behalf of EVA, I was involved in producing the report *Operation of the U.S. Power Grid During the January 2025 Polar Vortex dated* February 2025 for America's Power. I am submitting this affidavit to verify the information in that report relating to PJM Interconnection, L.L.C. ("PJM"), which America's Power is submitting to the Federal Energy Regulatory Commission.

2. A new record for electricity demand of 132 GW was set in the PJM region during the January 2025 Polar Vortex.

3. Almost 25% of the 132 GW of demand was met by coal-fired generation, and over 70% was met by fossil fuel generation.

4. The dispatch of coal-fired generation during the 2025 Polar Vortex was instrumental in dampening price volatility in the electricity market because coal prices remained stable during the event averaging \$2.50/MMBtu, while natural gas prices were subject to substantial variability (rising from less than \$2/MMBtu in November to almost \$30/MMBtu when the weather event peaked).

5. As indicated in the report, without the contributions of the coal generation fleet, our calculations conclude that the \$225/MWh peak prices during the event could

have ranged between $400/MWh and $650/MWh, potentially adding $500 million to $1.4 billion in extra costs for consumers during the single event.

6. The contributions of coal during this event show that coal-fired plants are essential to ensuring reliable and affordable electricity service to electric consumers in PJM.

7. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER25-1357-000

VERIFICATION OF SETH SCHWARTZ

I, Seth Schwartz, hereby declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the statements contained in my affidavit, are true and correct to the best of my knowledge, information, and belief.

Executed this 12th day of March 2025.

Seth Schwartz
____
Seth Schwartz