BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, In the Form of an Electric Security Plan.	)))))	Case No. 23-23-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	)))	Case No. 23-24-EL-AAM

DIRECT TESTIMONY OF KEVIN M. MURRAY ON BEHALF OF THE OHIO ENERGY GROUP

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin M. Murray. My business address is 5856 Newbridge Drive, Dublin, Ohio 43017-2622.

Q. By whom are you employed and in what position?

A. I am self-employed as the owner of K M Energy Consulting LLC.

Q. Please describe your educational background.

A. I graduated from the University of Cincinnati in 1982 with a Bachelor of Science degree in Metallurgical Engineering.

Q. Please describe your professional experience.

A. I was employed from 1997 to 2023 by McNees, Wallace & Nurick LLC ("McNees") as a Technical Specialist where I focused on helping larger commercial and industrial customers address issues that affect the price and availability of utility services. Between 2010 and 2022 I also served as the Executive Director of the Industrial Energy Users-Ohio, a frequent participant in proceedings before the Public Utilities Commission of Ohio ("Commission" or "PUCO"). I have also been actively involved, on behalf of commercial and industrial customers, in the formation of regional transmission operators ("RTOs") and the organization of regional electricity markets from both the supply-side and demand-side perspective. I previously served as an end-use customer sector representative on the Midcontinent Independent Transmission System Operator, Inc. ("MISO") Advisory Committee, including one year as chairman and several years as vice-chair. I have been actively involved in MISO working groups that focus on various electricity market issues since 1999. Prior to joining McNees, I was employed by the law firm of Kegler, Brown, Hill & Ritter ("KBH&R") in a similar capacity. Prior to joining KBH&R, I spent 12 years with The Timken Company, a specialty steel and roller bearing manufacturer. While at The Timken Company, I worked within a group that focused on meeting the electricity and natural gas requirements for facilities in the United States. I also spent several years in supervisory positions within The Timken Company's steelmaking operations (now TimkenSteel).

Q. Have you previously testified before the Commission?

A. Yes. The proceedings before the Commission in which I have submitted expert testimony are identified in Exhibit KMM-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to recommend that the Commission approve Ohio Power Company's ("AEP Ohio" or "Company") proposal to continue the Legacy Customers IRP ("IRP-L") and the Expanded IRP ("IRP-E") interruptible rate programs, with several modifications.

AEP Ohio's long-standing interruptible rate programs have demonstrated their value on multiple occasions, providing important reliability benefits to the grid in times of crisis. Recent events and projected changes to the electricity industry reinforce the continued need for interruptible rates and robust customer participation. Interruptible rates also promote economic development within Ohio by facilitating the state's competitiveness with other states that offer such rates.

While I am generally supportive of the Company's proposal, I recommend that the Commission adopt that proposal with the following modifications:

- Permit customers participating in either the IRP-L or IRP-E programs to annually reset their firm service levels to reflect operational changes, without increasing the amount of their interruptible capacity, effective on the first date of the Electric Security Plan ("ESP");

- Adopt a more gradual phase-down of the IRP-L demand credits than proposed by AEP Ohio, transitioning to a $7/kW-month credit rather than a $4/kW-month credit;
- Revise the IRP-L tariff to reflect the minimum credit level of 70% of the PJM Base Residual Auction price as recommended by AEP Ohio;
- Establish a minimum credit level for IRP-E customers similar to what is proposed for IRP-L customers set at 70% of the IRP-L credit level;
- Establish limits on the total number of hours that customers participating in the IRP-L and IRP-E programs can be interrupted (200 hours total per year with a daily interruption limit of 14 hours);
- Allow customers already located within AEP Ohio's service territory as well as new customers to participate in the IRP-E program through reasonable arrangements;
- AEP Ohio's proposal to include aggregate program cost caps is unnecessary. Because the size of IRP-E is already capped at 160 MW, there does not also need to be a cost cap. For IRP-E reasonable arrangements, the Commission can consider the costs versus benefits on a case-by-case basis;
- IRP-L customers should be permitted to participate in PJM's energy market as demand response resources to provide economic energy and reserve products.

Additionally, due to changed circumstances, I recommend the Commission use this proceeding to adopt a revised significantly excessive earnings test ("SEET") that would be applied to AEP Ohio during the term of the proposed ESP. I recommend that the Commission adopt the SEET safe harbor as the SEET threshold.

INTERRUPTIBLE RATE ISSUES

Q. Please provide a brief history of AEP Ohio's interruptible rates.

A. AEP Ohio has offered interruptible rates to its customers for decades, initially through special contracts and then through tariffed rates.[1] While the tariff terms have evolved over time, interruptible rates have been approved continuously from AEP Ohio's first ESP in 2009 through each of the Company's subsequent ESPs. And the Commission has repeatedly recognized the value of interruptible rate programs.[2]

In AEP Ohio's second ESP, the Commission approved both continuation of the Company's interruptible rate program and an increase in the level of the credit available to participating customers. The Commission stated that increasing the then-effective interruptible rate program credit to $8.21/kW-month was reasonable given the value that interruptible service provides and the fact that interruptible customers must be prepared to curtail their electric usage on short notice.[3] The Commission also noted the economic development benefits of offering an interruptible rate and the flexibility that the interruptible rate provides by allowing customers to determine their desired service quality.[4] Additionally, the Commission acknowledged the value of the interruptible program as a demand response resource.[5]

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[1] AEP Ohio entered into special contracts for interruptible service as far back as the 1970s and had an (Interruptible Power) IRP tariff as far back as the 1980s.
[2] Case Nos. 08-917-EL-SSO and 08-918-EL-SSO.
[3] Case No. 11-346-EL-SSO, Order (August 8, 2012) at 26.
[4] Case No. 11-346-EL-SSO, Order (August 8, 2012) at 26.
[5] Case No. 11-346-EL-SSO, Order (August 8, 2012) at 26.

In AEP Ohio's third ESP, the Commission again approved continuation of the Company's interruptible rate program. In doing so, the Commission expressly stated that continuation of interruptible rates offers "*numerous benefits, including the promotion of economic development and the retention of manufacturing jobs, and furthers state policy*."[6]

In AEP Ohio's fourth ESP, the Commission again reiterated the numerous benefits provided by the Company's interruptible program, and noted the Commission's long history of approving interruptible rate programs in other Ohio utility service territories.[7] The Commission found that the modifications made to the interruptible rate programs in AEP Ohio's fourth ESP, which expanded access to the program, enhanced participant benefits, and instituted cost controls, were in the public interest and should be approved.[8]

Q. Is AEP Ohio proposing to continue the interruptible rate programs approved by the Commission in ESP 4?

A. Yes, but with some modifications. AEP Ohio is proposing to continue its IRP-L program for up to 200 MW of interruptible capacity through the end of the ESP term. However, the Company suggests that the Commission phase-down the level of the credit available to participating customers by $1 per kW each year beginning in June 1, 2025. This proposal would result in the IRP-L credit decreasing to $4/kW-month

[6] Case No. 13-2385-EL-SSO, Order (February 25, 2015) at 40.
[7] Case No. 16-1852-EL-SSO, Order (April 25, 2018) at 57.
[8] Case No. 16-1852-EL-SSO, Order (April 25, 2018) at 58.

by June 1, 2029. AEP Ohio also proposes to set a minimum credit level for IRP-L customers equal to the IRP-E program credit.

With respect to its IRP-E program, AEP Ohio is proposing to continue to offer the program to up to 160 MW of existing IRP-E customers through the end of the ESP term or until such time as the program has paid $30 million in aggregate credits to existing customers. The Company also seeks to open the IRP-E program to customers that are new to the service territory in the context of reasonable arrangements through the end of the ESP term or until such time as the program has paid $25 million in aggregate credits to new customers.

Q. How have AEP Ohio's interruptible rate programs benefited customers?

A. Interruptible customers have demonstrated their value to the system on multiple occasions by curtailing their operations (at a cost to their company's productivity) during periods where the electric grid was strained. For example, interruptible customers were called upon to curtail their usage during the polar vortex in 2014, and did so. Interruptible customers were again called upon to curtail during a system emergency on October 2, 2019, and did so. And more recently, interruptible customers were curtailed for long durations on December 23 and December 24, 2022 in order to avoid rolling blackouts during Winter Storm Elliott. The curtailment on December 24, 2022 was for fourteen straight hours. The availability of interruptible load was critical to preserving the reliability of the grid during these crisis periods.

Q. Why have interruptible rate programs such as AEP Ohio's become even more critical recently?

A. The electric grid is currently in a period of transition. Major changes to the generation resource mix and increased load growth have introduced grid reliability concerns and increased the value of existing resources that bolster grid reliability, including utility interruptible load programs. Because of the new Intel load and the growth of data centers in central Ohio, this is particularly true in AEP Ohio's service territory.

As PJM recently explained, the accelerated retirement of thermal generation is outpacing the growth of new dispatchable generation and when combined with increased load, there is a substantial risk that PJM will not have adequate resources to maintain reliability in the future. In its recent whitepaper, *Energy Transitions in PJM: Resource Retirements, Replacements, & Risks*, PJM wrote that *"[t]he potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources."*[9] This asymmetry likewise underscores the importance of maintaining existing resources that support the reliability of the grid, such as AEP Ohio's interruptible rate program.

The PJM Board of Managers wrote that *"[w]hile PJM currently has a healthy reserve margin, Winter Storm Elliott demonstrated that PJM is not immune to reliability challenges as the system was stressed, even with a reserve margin in excess of the target and a lower level of renewable penetration than other regions.*

[9] Attachment KMM-2.

Although PJM and our members maintained grid reliability throughout Winter Storm Elliott, we believe this event demonstrates a need to focus on PJM's rules and processes to ensure reliability is maintained both now and throughout the transition."[10]

On April 11, 2023, PJM asked the Federal Energy Regulatory Commission ("FERC") for approval to delay the upcoming Reliability Pricing Model ("RPM") auctions to allow time for consideration of market changes meant to enhance grid reliability.[11] Additionally, the North American Reliability Corporation ("NERC") recently revised its standards to address extreme cold weather preparedness in the hopes of avoiding sustained outages like those experienced in Texas and the South Central U.S. in 2021.

The U.S. EPA and Department of Energy also recently published a Joint Memorandum of Understanding emphasizing the need to maintain the reliability of the power grid during the current energy transition. In the press release announcing the Joint Memorandum of Understanding, EPA Administrator Michel S. Regan stated that *"[a] reliable electric power system is essential to our national security, continued economic growth and the protection of public health. That's why DOE and EPA are uniting our long-standing efforts to ensure a robust and resilient system, especially as the power sector accelerates the transition to low- and zero-carbon energy sources."*[12]

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[10] Attachment KMM-3.
[11] Attachment KMM-4.
[12] Attachment KMM-5.

PJM's generation interconnection queue reinforces the degree to which the energy transition is underway. As of April 30, 2023, PJM's interconnection queue had 183,279 MW of generation projects awaiting approval for interconnection. Of this, 53,871 MW were storage projects, 74,300 MW were solar projects, 18,945 MW were wind projects, 30,016 MW were hybrid projects, 5,518 MW were natural gas projects, and the remaining 629 MW were classified as other projects. Based upon this snapshot, almost 97% of the projects in PJM's interconnection queue are associated with renewable energy facilities.

With the passage of the Inflation Reduction Act ("IRA"), the energy transition will be accelerated. Production tax credits ("PTC") and investment tax credits ("ITC") for wind and solar generation facilities that were due to expire earlier this decade were extended through the end of 2024 and new PTCs and ITCs were established beginning January 1, 2025. The technology-neutral PTC provides a credit of 1.5 cents per kWh for renewable energy sources. Stackable bonus credits of an additional 10% for meeting domestic manufacturing content requirements are available as well as an additional 10% credit for facilities located in certain energy communities. A new technology-neutral ITC is also available beginning January 1, 2025 for clean energy technologies that provides a tax credit rate of 30% of the investment, with stackable bonuses of 10% for meeting domestic manufacturing content requirements as well as an additional 10% credit for facilities located in certain energy communities.[13] These very significant PTCs and ITCs send a strong price signal for merchant developers to

[13] This includes solar, geothermal, fiber-optic solar, fuel cell, microturbine, small wind, off-shore wind, combined heat and power and waste energy recovery properties.

build non-dispatchable resources, which crowds out the thermal generation needed for reliability.

Q. Has FERC acknowledged the reliability issues associated with the current energy transition?

A. Yes. In a May 4, 2023 hearing before the U.S. Senate Energy and Natural Resources Committee, multiple FERC Commissioners emphasized the reliability issues stemming from the accelerated retirement of thermal generation without commensurate new generation to offset the loss of supply. Commissioner James P. Danly warned of "*the impending, but avoidable, reliability crisis that will likely result from FERC's maladministration of our wholesale electric markets. Most of these market-distorting forces originate with subsidies—both state and federal—and from public policies that are otherwise designed to promote the deployment of non-dispatchable wind and solar assets or to drive fossil-fuel generators out of business as quickly as possible."*[14] Likewise, Commissioner Mark C. Christie cautioned that *"[t]he United States is heading for a reliability crisis. I do not use the term 'crisis' for melodrama, but because it is an accurate description of what we are facing. I think anyone would regard an increasing threat of system-wide, extensive power outages as a crisis."*[15]

Q. Has Commission Staff acknowledged that PJM is undergoing a significant energy transition which impairs resource adequacy?

[14] Attachment KMM-6.
[15] Attachment KMM-7.

A. Yes. On May 2, 2023, the Commission's Office of the Federal Energy Advocate submitted comments to FERC in Docket No. ER23-1609-000. Those comments state *"[t]he PJM region is currently undergoing an expansive, multiphase energy transition from predominantly thermal generation resources to lower-carbon resources. This transition is detailed in PJM's recent report, "Energy Transition in PJM: Resource Retirements, Replacements, and Risks" ("4R Report"). Therein, PJM highlights the 'potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry,' thus impairing PJM's ability to ensure resource adequacy through 2030."* (footnotes omitted).[16]

Q. Have PUCO Commissioners expressed similar concerns?

A. Yes, and specifically Commissioner Dan Conway. In a written advanced statement submitted to FERC prior to a scheduled June 15, 2023 forum to review the operations, objectives and performance of PJM's capacity market, also known as the Reliability Pricing Model or "RPM", Commissioner Conway stated *"I am increasingly concerned about whether that capacity market is going to be able to achieve its purpose going forward. We are seeing the rapid retirement of existing thermal baseload dispatchable resources that are rich in both the quantity and range of attributes critical to meeting our resource adequacy and reliability objectives: dispatchability/availability, ramping capability, fuel security/assurance, black-start capability, voltage stabilization, and the ability to deliver long-duration energy at a high level of output. Simultaneously, the interconnection queue is filled*

[16] Attachment KMM-8.

with replacement resources, mostly intermittent renewable ones, that are relatively poor in both the quantity and range of such attributes. On top of that, the nameplate ratings for the resources that make their way through development and go into service must be significantly discounted in most cases, in order to depict accurately what their capacity values actually are. On the demand side of things, experts, including PJM, are predicting forecasted demand in the RTO to spike due to electrification of transportation, domestic heating, water heating and cooking, and data centers. PJM's recent evaluation of this combination of trends is unsurprising. Reserve margins are deteriorating, and resource adequacy and reliability are at risk, as explained in PJM's recent February report. Reliability First and NERC confirm these trends and the risks that they present both for PJM and the nation." (footnotes omitted)[17]

Q. Has NERC indicated that the power grid is facing increased reliability risk?

A. Yes. In its 2023 Summer Assessment issued May 17, 2023, NERC warned that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand.[18] While there are no high-risk areas in this year's assessment, the number of areas identified as being at elevated risk has increased. The assessment finds that, while resources are adequate for normal summer peak demand, if summer temperatures spike, seven areas — the U.S. West, SPP and MISO, ERCOT, SERC

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[17] Attachment KMM-9
[18] Attachment KMM-10.

Central, New England and Ontario — may face supply shortages during higher demand levels.

Q. Has NERC even more recently reaffirmed its concerns on reliability risks associated with the rapid and disorderly transition in the electric industry?

A. Yes. On June 1, 2023 the U.S. Senate Energy and Natural Resources Committee held a hearing on the reliability and resiliency of electric service in the United States. At the hearing, NERC President and Chief Executive Officer James B. Robb testified that *"[t]he bulk power system (BPS) is at an inflection point. The current electric transmission grid is highly reliable and resilient, and has grown more so under the current reliability regime. Yet the risk profile to customers is steadily deteriorating. Factors contributing to the deterioration include:*

- *Rapid, often disorderly transformation of the generation resource base,*
- *Performance issues associated with replacement resources as conventional resources retire,*
- *Wide-area, long duration weather events, which are becoming more frequent,*
- *And increased demand due to electrification, coupled with slow development of new energy infrastructure needed to support grid resilience and the clean energy future.*

Independent technical assessments by the North American Electric Reliability Corporation (NERC) find that the energy transformation can be navigated in a reliable way, provided that reliability is recognized as a central priority. NERC is concerned that the pace of change is overtaking the reliability needs of the system. Unless reliability and resilience are appropriately prioritized, current trends *indicate the potential for more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events."*[19]

Q. Why is it important for the Commission to maintain grid reliability resources like AEP Ohio's interruptible rate programs at the state level?

A. While PJM recognizes the risk that the retirement of thermal resources is posing to grid reliability, PJM cannot order that new generation resources be constructed. Nor can PJM order that generation resources within its region remain in operation. PJM may provide Reliability Must Run payments in order to incent existing generation units to remain operating but cannot force them to do so. With respect to the generation resource mix, the only tool available to PJM is to change its market rules to send price signals aimed at maintaining and promoting the construction of dispatchable thermal generation. But any PJM price signal to build and maintain dispatchable coal and gas generation must overcome the price signals contained in the IRA (PTCs and ITCs) to build non-dispatchable wind and solar. PJM's future resource mix is therefore dependent upon the will of the merchant generation developers within the PJM region.

States can enhance local reliability via load-side resources, such as utility interruptible load programs. If they choose to do so, states can also control their own generation resource mixes. In Ohio, because the electric utilities no longer own generation units outside of the Ohio Valley Electric Corporation, the generation mix is largely left to PJM's administration of the market. But Ohio's electric distribution

[19] Attachment KMM-11.

utilities can still utilize load-side resources to bolster grid reliability amid the current energy transition.

While PJM offers wholesale demand response programs, the terms and conditions of those programs are outside of the Commission's control and may ultimately be insufficient to induce large industrial manufacturers to physically curtail their operations and disrupt their production. For instance, the risk of high Capacity Performance penalties under the PJM demand response program may discourage large energy users from participating in that program. The trendline in recent years has shown a decline in participation in PJM demand response programs.[20] Preserving retail interruptible load programs allows the Commission to design programs that encourage Ohio's large energy users to enhance grid reliability.

Q. How does continuation of AEP Ohio's interruptible rate programs promote economic development?

A. Offering retail interruptible rate programs helps ensure that Ohio's electric rates are competitive compared to the rates available in other states. Ohio's large industrial energy users must compete both nationally and globally, and electric power prices are a major factor in their economic success. Ohio's neighbors, Indiana and Kentucky, offer interruptible rate programs, as do many other states. For example, AES Indiana provides a $6 per kW-month credit to interruptible customers, limiting interruptions to no more than 200 hours per year.[21] Louisville Gas & Electric Company provides a $5.90 per kW-month credit to high voltage interruptible customers, limiting

[20] Attachment KMM-12.
[21] Attachment KMM-13.

interruptions to no more than 100 hours per year.[22] Continuing interruptible rate programs therefore helps Ohio maintain its economic competitiveness among other states.

Q. Do you support AEP Ohio's proposal to continue its interruptible rate programs in this proceeding?

A. Yes, but with modifications.

Q. How would you modify the interruptible rate programs as proposed by AEP Ohio?

A. I recommend that the Commission approve AEP Ohio's proposal with the following modifications.

First, the Commission should permit customers participating in either the IRP-L or IRP-E programs to annually reset their firm service levels to reflect operational changes, without increasing the amount of their interruptible capacity, effective on the first date of the ESP. Business operations can fluctuate significantly from year to year, and the interruptible program requirements should include flexibility in order to recognize such operational changes.

Second, the Commission should adopt a more gradual phase-down of the IRP-L demand credits than proposed by AEP Ohio, transitioning to a $7/kW-month credit ($9/kW-month in year one, $8/kW-month in year two, $7/kW-month in all other years) rather than a $4/kW-month credit. As discussed above, AEP Ohio's

[22] Attachment KMM-14.

interruptible program has existed for decades and many interruptible customers have built their operations in reliance upon the current programs. The Company's proposed reduction is too drastic and should be modified to a more gradual approach.

Third, the Commission should revise the IRP-L tariff to reflect the minimum credit level for participating customers. The minimum credit proposed by AEP Ohio is 70% of the PJM Base Residual Auction price. While an IRP-L minimum credit is proposed in AEP Ohio's application, that minimum credit is not yet reflected in the proposed IRP-L tariff.

Fourth, the Commission should establish a minimum credit for IRP-E customers similar to what is proposed for IRP-L customers. That credit should be set at 70% of the IRP-L credit level. Because the IRP-E credit is set at 70% of the PJM Base Residual Auction clearing price for the AEP Zone, the level of that credit fluctuates from year to year. Establishing a minimum credit provides some level of price certainty for customers participating in the IRP-E program.

Fifth, establish limits on the total number of hours that customers participating in the IRP-L and IRP-E programs can be interrupted (200 hours total per year with a daily interruption limit of 14 hours). Both PJM and other states establish limits on the hours that the operations of interruptible customers may be curtailed. It is reasonable for Ohio to do the same.

Sixth, OEG supports AEP Ohio's proposal to allow up to 160 MW of grandfathered IRP-E customer load to continue to participate in the program through ESP 5. The Commission should also allow customers already located within AEP Ohio's service territory as well as new customers to participate in IRP-E through reasonable arrangements. AEP Ohio proposes to allow only customers that are new to the service territory to access additional IRP-E load pursuant to a reasonable arrangement. But all customers should have the right to pursue IRP-E participation via a reasonable arrangement.

AEP Ohio already has at least one customer participating in the IRP program pursuant to a reasonable arrangement, which is presently scheduled to end along with ESP 4.[23] That customer should not be barred from continuing its participation in the IRP program through an extension of its reasonable arrangement.

Seventh, the Commission should not impose a program dollar cost cap for existing IRP-E customers or for reasonable arrangement customers. Because the size of IRP-E is already capped at 160 MW, there does not need to also be a dollar cost cap. For IRP-E reasonable arrangements, the Commission can consider the costs versus benefits on a case-by-case basis. As discussed above, interruptible rate programs are a valuable grid reliability resource and promote economic development within Ohio. The Commission should therefore seek to expand, not restrict, participation in those programs.

Finally, the Commission should clarify that IRP-L customers are permitted to participate in PJM's markets to provide economic energy and reserve products. Rider IRP-L requires participating customers to actively bid their interruptible capacity into PJM capacity auctions and remit any revenues received back to AEP Ohio. That should not change as it reduces the cost to non-participants. However, the tariff is silent on the ability of IRP-L to offer their demand response capacity as economic

[23] Case No. 17-2132-EL-AEC.

energy and/or reserve products. The Commission's order should remove any ambiguity and state that IRP-L customers may offer their demand response capacity as economic energy and/or reserve products and retain any resulting revenues.

SIGNIFICANTLY EXCESSIVE EARNINGS TEST MODIFICATIONS

Q. Are there additional issues the Commission should address as part of this proceeding?

A Yes. Due to changed circumstances the Commission should adopt a new standard for applying the SEET during the term of the ESP. The Commission should adopt the SEET safe harbor as the SEET threshold.

Q. Historically, how has the SEET been applied by the Commission and AEP Ohio?

A. The SEET is a statutorily required review to determine whether the utility's earnings in the prior year were significantly excessive thus requiring customer refunds. The retrospective SEET review is a statutory exception to the *Keco* doctrine, which generally prohibits retroactive rate adjustments. The SEET can be an important tool for protecting consumers as witnessed by FirstEnergy's recent $306 million SEET refund.

AEP Ohio begins the SEET process by identifying a list of companies in a comparable group deemed to face similar business and financial risk and what their annual return-on-equity ("ROE") was in the same year. Adjustments are made to remove the effect of impairments and other one-time adjustments during the year.

The comparable group is then scrubbed to remove companies deemed outliers due to unusual events. After making these adjustments, the average ROE is calculated. The SEET threshold is set by applying a 1.64 standard deviation multiplier to the average ROE. Additionally, the Commission has adopted a "safe harbor". The safe harbor is the average ROE of the comparable group plus 200 basis points. If AEP Ohio's actual earned ROE is less than the safe harbor then the analysis ends. If its ROE is above the safe harbor, then a more detailed analysis is required to determine if its earnings were significantly excessive and a customer refund is due.

Q. In its June 30, 2010 Order in Case No. 09-786-EL-UNC, what guidance did the Commission offer on factors it would consider when applying the SEET?

A. The Commission stated *"[t]he Commission notes that within Ohio's electric utilities, there is significant variation, including, for example, whether the electric utility provides transmission, generation, and distribution service or only distribution service. For this reason, the Commission will give due consideration to certain factors, including, but not limited to, the electric utility's risk, including the following: whether the utility owns generation; whether the ESP includes a fuel or purchased power adjustment or other similar adjustments; the rate design and the extent to which the electric utility remains subject to weather and economic risk; capital commitments and future capital requirements; indications of management performance and benchmarks to other utilities; and innovation and industry leadership with respect to meeting industry challenges to maintain and improve the* *competitiveness of Ohio's economy, including research and development expenditures/investments in advanced technology, and innovative practices; and the extent to which the electric utility has advanced state policy. We therefore, direct the electric utilities to include this information in their SEET filings."*

Q. Have the risk factors that AEP Ohio is exposed to changed since the Commission's 2010 Order in Case No. 09-786-EL-UNC?

A. Yes, in a number of ways. First, AEP Ohio no longer owns any generation assets, it is a wires-only transmission and distribution company. Second, AEP Ohio no longer has a fuel and purchased power adjustment mechanism, as generation supply for the standard service offer is procured through periodic auctions. Third, AEP has proposed to continue its Distribution Investment Rider ("DIR") and Enhanced Service Reliability Rider during the term of the ESP. Although AEP Ohio has proposed annual caps for the DIR, they are proposing to carve out from the caps distribution work they describe as related to obligation to serve projects. These include projects for economic development, new customer load, public project relocation work and third-party work requests, etc. It is important to note that obligation to serve distribution projects include new revenue sources. This is in contrast to DIR replacement projects. All of these factors, relatively speaking, lower the risks that AEP Ohio is exposed to compared to those that existed at the time of the Commission's SEET guidance in 2010.

Q. Should capital commitments and future requirements be used to raise the SEET threshold?

A. No, certainly not in this case. A utility's future capital commitments that are subject to rider recovery present an earnings opportunity through rate base growth, not a risk. Capital additions that are subject to base rate recovery through the historic test year ratemaking process and associated regulatory lag raise different issues.

Q. Do you recommend the Commission adopt changes to its SEET as part of its Order approving an ESP?

A. Yes. Due to the changed circumstances and reduced risk to AEP Ohio, I recommend that the Commission eliminate the SEET threshold test of 1.64 standard deviations times the mean ROE of the comparable group and adopt its safe harbor (200 basis points above the mean ROE) as the SEET threshold for the term of the ESP. Lowering the SEET threshold to the safe harbor strikes a more appropriate ratepayer/shareholder balance.

Q. What is the effect of your recommendation?

A. The following chart shows AEP Ohio's approved ROE for distribution assets, the mean ROE of the comparable group, the safe harbor and the SEET threshold using the 1.64 standard deviation for 2020-2022. Over that three-year period, adopting the safe harbor would lower the SEET threshold by 2.69% on average. On a dollar basis, this would lower the annual SEET earnings threshold by approximately $79.8

million. With this added ratepayer protection, a higher DIR and obligation to serve carve out could be justified.

	Approved ROE for Distribution Assets	Mean ROE Comparable Group	Safe Harbor	SEET Threshold 1.64 Standard Deviation
2020	10.2%	10.58%	12.58%	14.64%
2021	9.7%	11.21%	13.21%	17.69%
2022	9.7%	10.14%	12.14%	13.66%
2020-2022 Avg.	9.86%	10.64%	12.64%	15.33%

Q. Does this conclude your direct testimony?

A. Yes.

Attachment KMM-1

Exhibit KMM-1

In the Matter of Enron Energy Services Inc., et al. v. FirstEnergy Corp., Ohio Edison Company., The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 01-393-EL-CSS

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Revised Code, in the Form of an Electric Security Plan, et al., Case Nos. 13-2385-EL-SSO, *et al.*

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Market Rate Offer, *et al.,* PUCO Case Nos. 12-426-EL-SSO, *et al.*

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, PUCO Case No. 10-2929-EL-UNC.

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, PUCO Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, *et al.*

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan, and the Sale or Transfer of Certain Generating Assets, Case No. 08-917-EL-SSO and *In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan*, PUCO Case No. 08-918-EL-SSO (remand phase).

In the Matter of the Application of Columbus Southern Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1089-EL-POR.

In the Matter of the Application of Ohio Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1090-EL-POR.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 09-906-EL-SSO.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, PUCO Case No. 08-935-EL-SSO.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 08-936-EL-SSO.

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets, PUCO Case No. 08-917-EL-SSO.

In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, PUCO Case No. 08-918-EL-SSO.

In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan, PUCO Case No. 08-920-EL-SSO.

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan, PUCO Case No. 08-1094-EL-SSO.

Attachment KMM-2

Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

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Contents

Executive Summary

Driven by industry trends and their associated challenges, PJM developed the following strategic pillars to ensure an efficient and reliable energy transition: facilitating decarbonization policies reliably and cost-effectively; planning/operating the grid of the future; and fostering innovation.

PJM is committed to these strategic pillars, and has undertaken multiple initiatives in coordination with our stakeholders and state and federal governments to further this strategy, including interconnection queue reform, deployment of the State Agreement Approach to facilitate 7,500 MW offshore wind in New Jersey, and coordination with state and federal governments on maintaining system reliability while developing and implementing their specific energy policies.

In light of these trends and in support of these strategic objectives, PJM is continuing a multiphase effort to study the potential impacts of the energy transition. The first two phases of the study focused on energy and ancillary services and resource adequacy in 2035 and beyond. This third phase focuses on resource adequacy in the near term through 2030.[1]

Maintaining an adequate level of generation resources, with the right operational and physical characteristics[2], is essential for PJM's ability to serve electrical demand through the energy transition.

Our research highlights four trends below that we believe, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry under a possible "low new entry" scenario:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

[1] See Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid | Addendum (2022).

[2] See previous work on Reliability Products and Services, including PJM's Evolving Resource Mix and System Reliability (2017), Reliability in PJM: Today and Tomorrow (2021), Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and work completed through the RASTF and PJM Operating Committee (2022).

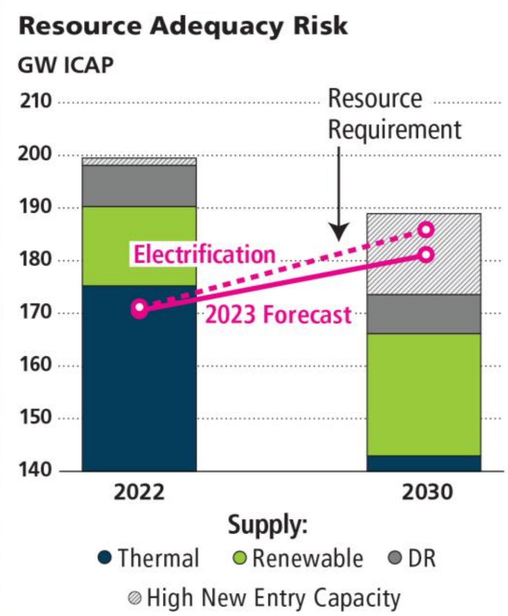
The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder initiatives, including capacity market modifications, interconnection process reform and clean capacity procurement, and the urgency for continued, combined actions to de-risk the future of resource adequacy while striving to facilitate the energy policies in the PJM footprint.

The first two phases of the energy transition study assumed that PJM had adequate resources to meet load.

In this this third phase of this living study, we explore a range of plausible scenarios up to the year 2030, focusing on the resource mix "balance sheet" as defined by generation retirements, demand growth and entry of new generation.

The analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity[3].

In addition to the retirements, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually.[4]



The projections in this study indicate that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.

On the other side of the balance sheet, PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. The projections in this study indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

In the study, we also consider generation entry beyond the queue using projections from S&P Global. Those projections indicate that, despite eroding reserve margins, resource adequacy would be maintained if the influx of renewables materializes at a rapid rate and gas remains the transition fuel, adding 9 GW of capacity. The analysis performed at the Clean Attribute Procurement Senior Task Force (CAPSTF) also suggests that further gas expansion is economic and competitive.[5]

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[3] Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.
[4] PJM Load Forecast Report, January 2023.
[5] CAPSTF Analysis, Initial Results; Emmanuele Bobbio, Sr. Lead Economist – Advanced Analytics, PJM, Dec. 16, 2022.

Balance Sheet Summary (2022–2030)				
Retirements **40 GW** **60% Coal** **30% Natural Gas** **10% Other**	**New Entry Wind/Solar[6]** **Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**New Entry Standalone Storage** **Low =** 3 GW **High =** 4 GW	**New Entry Thermal** **Low =** 4 GW **High =** 9 GW	**Load Growth** **2023 Forecast =** 11 GW **Electrification Forecast =** 13 GW
Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.				

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources and demand response, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy. The potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources.

[6] Includes hybrid projects with battery storage

Background

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an Installed Reserve Margin in excess of the forecast peak load that achieves a loss-of-load expectation (LOLE) of one day in 10 years. This LOLE standard is consistent with that prescribed in the ReliabilityFirst Corporation standard for planning resource adequacy.[7]

Long-term reliability and resource adequacy are addressed through the combined operation of PJM's electricity markets, and in particular the capacity market, called the Reliability Pricing Model (RPM). Each PJM member that provides electricity to consumers must acquire enough power supply to meet demand, not only for today and tomorrow, but for the future. Members secure these capacity resources for future energy needs through a series of base and incremental capacity auctions, as well as Fixed Resource Requirement plans.

The capacity market ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand up to three years in the future. These capacity resources have an obligation to perform during system emergencies, and are subject to penalties if they underperform. By matching generation with future demand, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies. This exchange provides consumers with an assurance of reliable power in the future, while capacity resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources, and encourage companies to develop new technologies and sources of electric power.

Methodology

The size, composition and performance characteristics of the resource mix will determine PJM's ability to maintain reliability. This study explores a range of scenarios in the context of resource adequacy, focusing on the resource mix "balance sheet" as defined by demand growth, generation retirements and new entry of generation. Using the methodology described in this section, PJM evaluates the future of resource adequacy by estimating the amount of capacity required to cover load expectations versus expected capacity for the years 2023 through 2030.

The study's initial supply levels are 192.3 GW of installed capacity from generation resources and 7.8 GW of installed capacity from demand response capacity resources. The generation mix is approximately 178.9 GW of thermal resources and 13.3 GW of renewables and storage.[8]

[7] RFC Standard BAL-502-RF-03: Planning Resource Adequacy Analysis, Assessment and Documentation

[8] This value includes the capacity value of run-of-river hydro, pumped storage hydro, solar, onshore wind, offshore wind and battery energy storage.

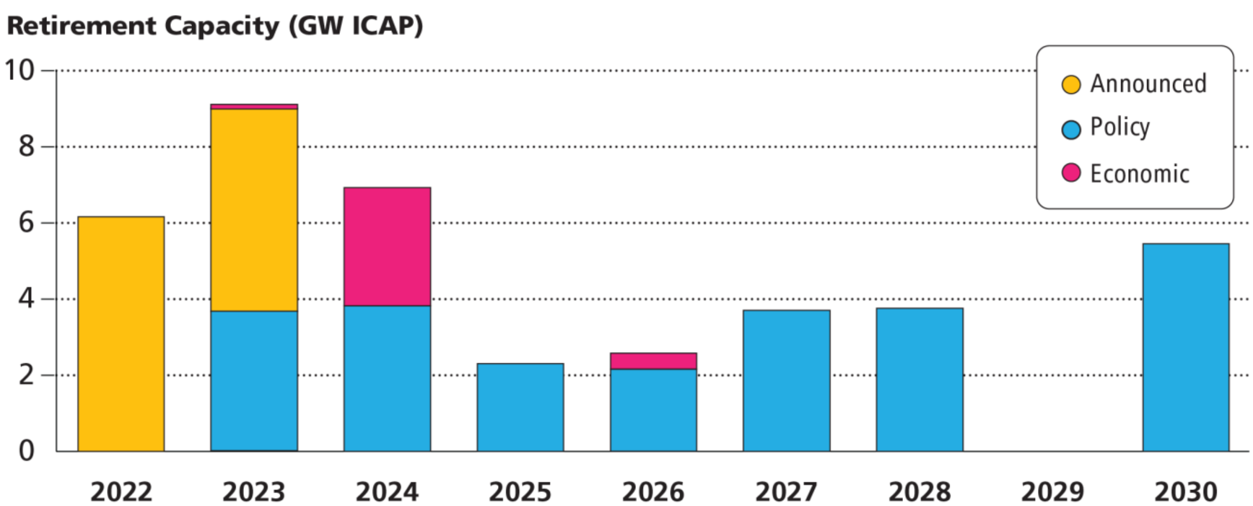
Supply Exits

PJM is undergoing a major transition in the resources needed to maintain bulk power grid reliability.

Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of conditions, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

This study estimates anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement. **Figure 1** highlights the 40 GW of projected generation retirements by 2030, which is composed of: 12 GW of announced retirements[9], 25 GW of potential policy-driven retirements[10] and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity.[11] This section describes each category of potential retirements in more detail.

Figure 1. Total Forecast Retirement by Year (2022–2030)



[9] Includes 6 GW of 2022 retirements.

[10] Note that 7 GW of the 25 GW of supply with policy risk was also identified to have more immediate economic risk. The year that these 7 GW of potential policy retirements shown in **Figure 2** is based on timing identified in the economic analysis. In **Figure 4**, these 7 GW are shown in terms of the regulatory compliance timeline alone. The timeline of these potential quantities of resource retirements does not factor in any reliability "off-ramps" that may be included in established policies.

[11] In this study, PJM assumes that a resource that exits would not return to service in a future delivery year, even if operational conditions improve. Historically, a small percentage of retiring units would instead enter a "mothball" or standby state, in which the unit is put into a state where it may not operate for one or more years; however, in order to obtain an operating permit renewal, the mothballed unit would have to comply with the most recent environmental standards, likely requiring costly upgrades, making investing in newer, cleaner technologies more inviting.

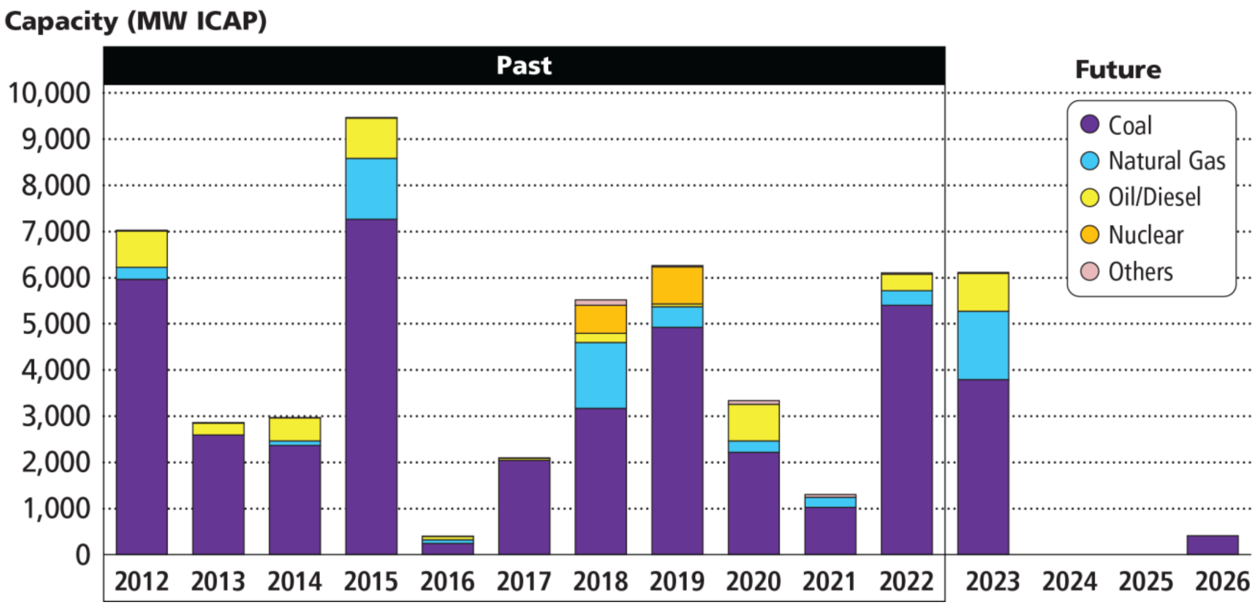
Announced Retirements

One of PJM's responsibilities is to ensure the continued reliability of the high-voltage electric transmission system when a generation owner requests deactivation. Through its Generation Deactivation process,[12] PJM identifies transmission solutions that allow owners to retire generating plants as requested without threatening reliable power supplies to customers. PJM may order transmission upgrades or additions built by transmission owners to accommodate the generation loss. PJM has no authority to order plants to continue operating. However, in some instances, to maintain reliability, PJM may formally request that a plant owner continue operating, subject to rates authorized by the Federal Energy Regulatory Commission (FERC), while transmission upgrades are completed.

Plant owners considering retirement must notify PJM at least two quarters before the proposed deactivation date. PJM and the transmission owners complete a reliability analysis in the subsequent quarter after notification to PJM. Generator retirements and any required system upgrades to keep the grid running smoothly are included in the PJM Regional Transmission Expansion Planning process and are reviewed with PJM members and stakeholders at the PJM Transmission Expansion Advisory Committee.

Between 2012 and 2022, 47.2 GW of generation retired in PJM, as detailed by fuel type in **Figure 2**. In 2022, approximately 6 GW of generation deactivated and an additional 5.8 GW announced ("future") deactivations over the 2023–2026 time frame. The deactivations are slightly above the 10-year average of 4.3 GW, but well under the historical annual peak of 9.5 GW in 2015. Coal-fired resources account for approximately 89% of retired capacity in 2022.

Figure 2. Past and Announced Future Retirements



[12] See process details in PJM Manual 14-D, Section 9, and tracking of deactivation requests at https://www.pjm.com/planning/services-requests/gen-deactivations.

Potential Policy Retirements

An analysis of federal and state policies and regulations with direct impacts on generation in the PJM region yielded the largest group of potential future retirements in this study.[13] As highlighted in **Figure 3**, the combined requirements of these regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame. These impacts will be reevaluated as these policies and regulations evolve. PJM will continue to work with both federal and state agencies on the development and implementation of environmental regulations and policies in order to address any reliability concerns.

Below are the policies and regulations included in the study:

EPA Coal Combustion Residuals (CCR): The U.S. Environmental Protection Agency (EPA) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. This led to a number of facilities, approximately 2,700 MW in capacity, indicating their intent to comply with the rule by ceasing coal-firing operations, which is reflected in this study.

EPA Effluent Limitation Guidelines (ELG): The EPA updated these guidelines in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028.[14] Importantly, but not included in this study, the EPA is planning to propose a rule to strengthen and possibly broaden the guidelines applicable to waste (in particular water) discharges from steam electric generating units. The EPA is expecting this to impact coal units by potentially requiring investments when plants renew their discharge permits, and extending the time that plants can operate if they agree to a retirement date.

EPA Good Neighbor Rule (GNR): This proposal requires units in certain states to meet stringent limits on emissions of nitrogen oxides (NOx), which, for certain units, will require investment in selective catalytic reduction to reduce NOx. For purposes of this study, it is assumed that unit owners will not make that investment and will retire approximately 4,400 MW of units instead. Please note that the EPA plans on finalizing the GNR in March, which may necessitate reevaluation of this assumption.

Illinois Climate & Equitable Jobs Act (CEJA): CEJA mandates the scheduled phase-out of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. To understand CEJA criteria impacts and establish the timing of affected generation units' expected deactivation, PJM analyzed each generating unit's publically available emissions data, published heat rate, and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones. For this study, PJM focuses on the approximately 5,800 MW expected to retire in 2030.

[13] Policies impacting forward energy prices, such as the Regional Greenhouse Gas Initiative and Renewable Energy Credits, are implicitly included in economic analysis but are not explicitly included in analysis of policy-related retirements.

[14] See State Impact PA, Nov. 22, 2021. These facilities have not filed formal Deactivation Notices with PJM.

[New Jersey Department of Environmental Protection CO_2 Rule]: New Jersey's CO_2 rule seeks to reduce carbon dioxide (CO_2) emissions of fossil fuel-fired electric generating units (EGUs) through the application of emissions limits for existing and new facilities greater than 25 MW. Units must meet a CO_2 output-based limit by tiered start dates. The dates and CO_2 limits are:

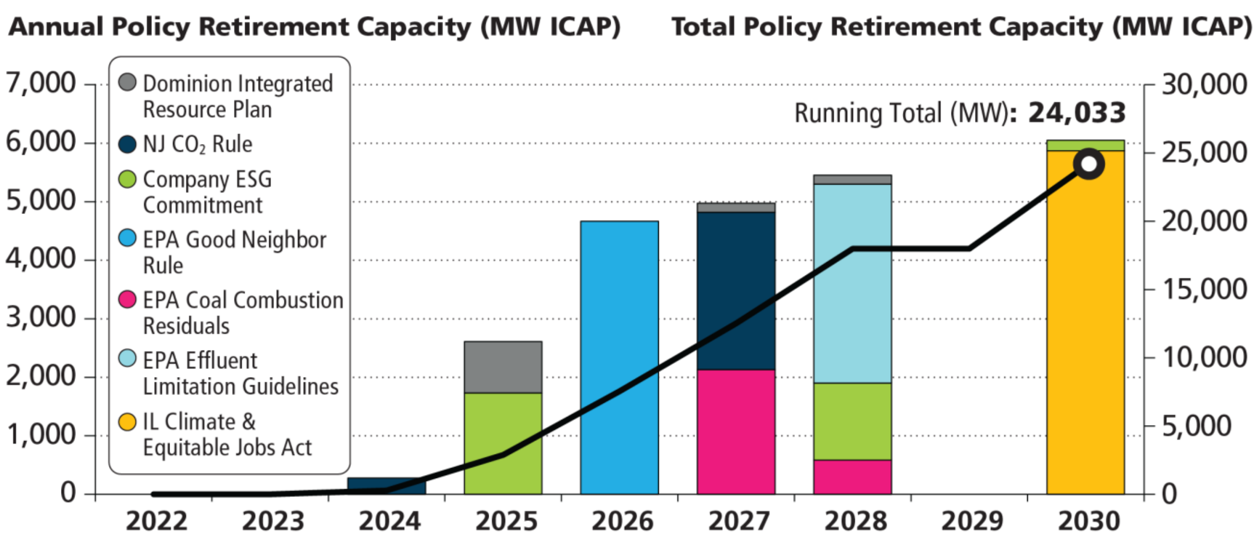
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

PJM used emissions data found in EPA Clean Air Markets Program Data to evaluate unit compliance. Where a unit's average annual emissions rate was greater than the CO_2 limit on the compliance date, the unit was assumed to be retiring. In this study PJM, estimated retirements at approximately 400 MW in 2024 and approximately 2,700 MW in 2027.

Dominion Integrated Resource Plan (IRP) commits to net zero carbon in its Virginia and North Carolina territory by 2050. PJM studied Dominion's Alternative Plan B retirement schedule, approximately 1,533 MW, for this analysis. Alternative Plan B proposes "significant development of solar, wind and energy storage resource envisioned by the VCEA," (Virginia Clean Economy Act of 2020), while maintaining natural gas generation for reliability, which is reflected in our analysis.

Company ESG (Environmental, Social, Governance) commitments are included where there is a commitment to retire resources per legal consent decree or other public statement. This includes the elimination of coal use and the retirement of the Brandon Shores, 1,273 MW, and Wagner, 305 MW, facilities in Maryland and the retirement of Rockport, 1,318 MW, in Indiana.

Figure 3. Potential Policy Retirements



Potential Economic Retirements

The third category of retirements in this study, beyond those formally announced and made likely by policy implementation, were identified through an analysis of revenue adequacy, the ability to economically cover going-forward costs from the wholesale markets. A net profit value was calculated for each existing generation resource using an estimate of future revenues and historical costs.

$$Net\ Profit = (\ Gross\ Energy\ \&\ Ancillary\ Service\ Revenue - Production\ Costs\ ) + (\ Capacity\ Revenue\ ) - (\ Fixed\ Avoidable\ Costs\ )$$

The results reveal that a portion of the thermal fleet is at risk of becoming unprofitable in the coming years.

The capacity market's Variable Resource Requirement (VRR) represents the set of prices for which load is willing to procure additional supply beyond the minimum reliability requirement. There are three points in the sloped demand curve, the first of which is anchored at a price 1.5 times the Net Cost of New Entry (Net CONE). Should the auction clear at this price level, the auction result signals that demand is willing to pay for the construction of new supply, minus the expected energy revenues the resource should expect to earn in the energy markets. As such, it is important to align the revenue expectations for the marginal resources with forward revenues, especially under PJM's continually changing landscape of business rules.

Energy & Ancillary Services Revenue and Production Cost

This study used a scaling approach to estimate forward unit-specific energy and ancillary services (E&AS) revenues from historical energy and ancillary service revenues by applying the following:

$$Fwd\ Unit\ E\&AS\ Revenue = Hist\ Unit\ E\&AS\ Revenue * \frac{Fwd\ Reference\ E\&AS\ Revenue^{15}}{Hist\ Reference\ E\&AS\ Revenue} * \frac{Reference\ Avg\ Heat\ Rate}{Unit\ Avg\ Heat\ Rate}$$

For a given reference resource type, unit dispatch was simulated using both historical and forward energy hub-adjusted energy prices. For the equivalent production cost model, the relative ratio of revenues and heat rates indicate the net effects of both rising fuel costs and energy price revenue. A unit on the margin in the energy markets, typically a natural gas unit, would set a locational price near its short-run marginal costs. Infra-marginal units, potentially coal units, would receive higher revenues as price-taking resources, and thus may see increased profitability. This is reflected in the analysis, in which a reference coal unit's forward revenues increased an average of 139% over previous revenue estimates.

[15] The forward energy and ancillary services revenue calculation used in this study is the method that was developed for use in the Forward Net Energy & Ancillary Services Offset calculation originally developed in 2020, and filed as part of the most recent Quadrennial Review.

Capacity Revenues and Fixed Avoidable Costs

Unit-specific capacity revenues were calculated from prices and cleared quantities in the 2023/2024 Base Residual Auction (BRA). The study used the published 2023/2024 BRA Default Gross Avoidable Cost Rate (ACR) values as representative total fixed costs ($/MW-day) required to keep the generating plant available to produce energy. In other words, these are projected costs that could be avoided by the retirement of the plant. Avoidable costs represent operational factors like operations and maintenance labor, fuel storage costs, taxes and fees, carrying charges, and other costs not directly related to the production of energy. When available, unit-specific ACR values from the 2023/2024 BRA supply offer mitigation process were used, otherwise the class average Gross ACR was used.

Results and Estimated Impact

This study assumes that a simulated economic loss would result in a retirement of the resource at the next available delivery year in which the unit is not committed for capacity. As such, a unit with a revenue loss that did not clear in the 2023/2024 BRA would exit in 2023, while a unit with a revenue loss that cleared in the 2023/2024 BRA would exit in 2024. While units that do not clear a single BRA may remain energy-only resources, this conservative assumption was used to provide awareness.

The economic analysis identified approximately 10 GW of supply in immediate economic risk, of which 7 GW of supply is also affected by policy risk, and 3 GW of supply is economic risk only. In aggregate, 6 GW are steam resources, and 4 GW represent combustion turbines and internal combustion resources. Several of the units identified were older steam boilers that had once converted from coal-fired to natural gas fuel; these resources are less efficient than a modern heat-recovery steam generator in a combined cycle unit. Fifty-three percent of the resources identified for economic risk did not have a PJM capacity obligation in Delivery Year 2023/2024, either through the FRR process or market clearing.

Supply Entry

The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue. The PJM New Services Queue stands at approximately 290 ICAP GW of generation interconnection requests, of which almost 94% (271 ICAP GW) is composed of renewable and storage-hybrid resources.

Natural Gas Headwinds

In the last decade, resources in the PJM region have benefitted from the proximity to the Marcellus Shale, an area that extends along the Appalachian Mountains from southern West Virginia to central New York. Beginning around 2010, gas extraction from hydraulic fracturing transformed this region into the largest source of recoverable natural gas in the United States. This local fuel supply decreased the prices for spot market natural gas in much of the PJM region, and prices in the PJM region often trade at negative basis to the Henry Hub spot price.

The entry of natural gas resources in the PJM region peaked in 2018, with 11.1 GW of generation commercializing that single year. From 2019 to 2022, a total of 8.1 GW of natural gas generation began service, or about a third of the 23 GW observed from 2015–2018. Queue proposals have also declined; over the last three years, only 4.1 GW of new natural gas projects entered the queue, while 15.1 GW of existing queue projects withdrew.[16]

Recent movement in the natural gas spot markets across the U.S. and Europe add another degree of uncertainty to future operations. In 2022, European natural gas supply faced many challenges resulting from the war in Ukraine and subsequent sanctions against Russia. Liquefied natural gas (LNG) imports into the EU and the U.K. in the first half of 2022 increased 66% over the 2021 annual average,[17] primarily from U.S. exporters with operational flexibility. This international natural gas demand is a new competitor for domestic spot-market consumers, resulting in significantly higher fuel costs for PJM's natural gas fleet.

This study assumes that, of the approximately 17.6 GW of natural gas generation in the queue, only those that are proposed uprates of existing generation, or currently under construction, will complete.[18] This results in 3.8 GW of entry from under-construction natural gas resources to be completed for the 2023/2024 Delivery Year. While 12 GW of natural gas have reached a signed Interconnection Service Agreement (ISA) stage, it is unclear what percentage of this capacity may move forward. If significantly more natural gas capacity achieved commercial operation, it could help avoid reliability issues.

Renewable Transition

PJM's projected resource mix continues to evolve toward lower-carbon intermittent resources. Entry into the queue from renewable and storage resources has been growing at an annualized rate of 72% per year since 2018, or 199 GW of capacity entry versus 2.8 GW commercializing and 42.1 GW withdrawn. This influx of renewable projects has led to a joint effort between PJM and its stakeholders to enact queue reforms intended to clear the backlog of projects, improve procedures around permitting and site control, simplify analysis by clustering projects, and accelerate projects that don't require network upgrades. FERC approved the proposed package in November 2022, with expected implementation in 2023.

Commercial Probability and Expanding Beyond the Queue

PJM staff developed several forecasts of the rate by which projects successfully exit the queue (the "commercial probability" of reaching an *In-Service* state). Since 1997, the PJM New Services Queue has tracked proposed generation interconnection projects from their submittal and study stages to completion of an ISA and Wholesale Market Participation Agreement (WMPA) and construction. At any point in the process, a resource may withdraw from the queue, effectively ending its commercial viability.

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[16] This capacity represents natural gas projects that were submitted prior to 2020 and withdrawn in the 2020–2022 time frame.

[17] [Europe imported record amounts of liquefied natural gas in 2022](), U.S. Energy Information Administration, June 14, 2022.

[18] Under construction includes the New Service Queue *Partially in Service – Under Construction* and *Under Construction* statuses.

The study utilized a logistical regression classification algorithm to predict the probability of a project reaching an *In-Service* entry (or *Withdrawn* exit) based on several properties of the project. A logistical regression searches for patterns within training datasets, resulting in a model that can forecast a probability of a result. After applying the logistical regression model for 10 years of historical project completion (Y-queue to present) without project stage, approximately 15.3 GW-nameplate/8.7 GW-capacity were deemed commercially probable out of 178 GW of projects examined.

The model results for thermal resources were reasonably in line with expectations. However, the model produced extremely low entry from onshore wind, offshore wind, solar, solar-hybrid and storage resources. The uncertainty of completion rates of newer resource types, like offshore wind, likely plays a role in these model outcomes. After adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030, as shown in **Figure 4**.

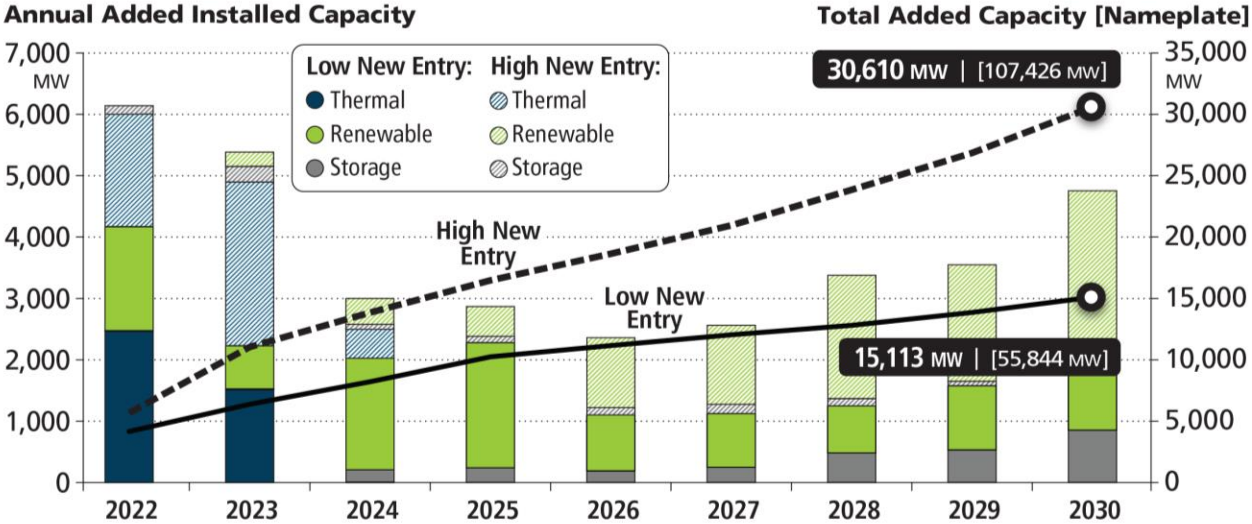
Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates of future entry beyond the queue, these models are used to provide additional insight for the two scenarios: "Low New Entry" utilizes the "Planning Model,"[19] and "High New Entry" utilizes the "Fast Transition" model.[20] Based on these models, PJM added additional capacity to its commercial probability data in each scenario.

These forecasts of generation expansion are economic resource planning solutions, which take state RPS requirements and capacity margins into account to ensure new renewable builds. Over the study period, the Low New Entry scenario adds 42.6 GW-nameplate/8.4 GW-capacity to supply expectations, resulting in total entry of 55.8 GW-nameplate/15.1 GW-capacity. The High New Entry scenario adds 107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity, as shown in **Figure 4**.

[19] S&P Global, North American Power Market Outlook, June 2022, planning model. This planning case incorporated effects from the 2021 Infrastructure Investment and Jobs Act, but not the 2022 Inflation Reduction Act.

[20] S&P Global, North American Power Market Outlook, Sept. 2022, Fast Transition model. This planning case assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies, and as such assumes adjustments for increased electrification of heating, tax credits for renewable generation and higher levels of fossil retirements.

Figure 4. Forecast Added Capacity



Impact of Capacity Accreditation on Existing Renewables and Storage

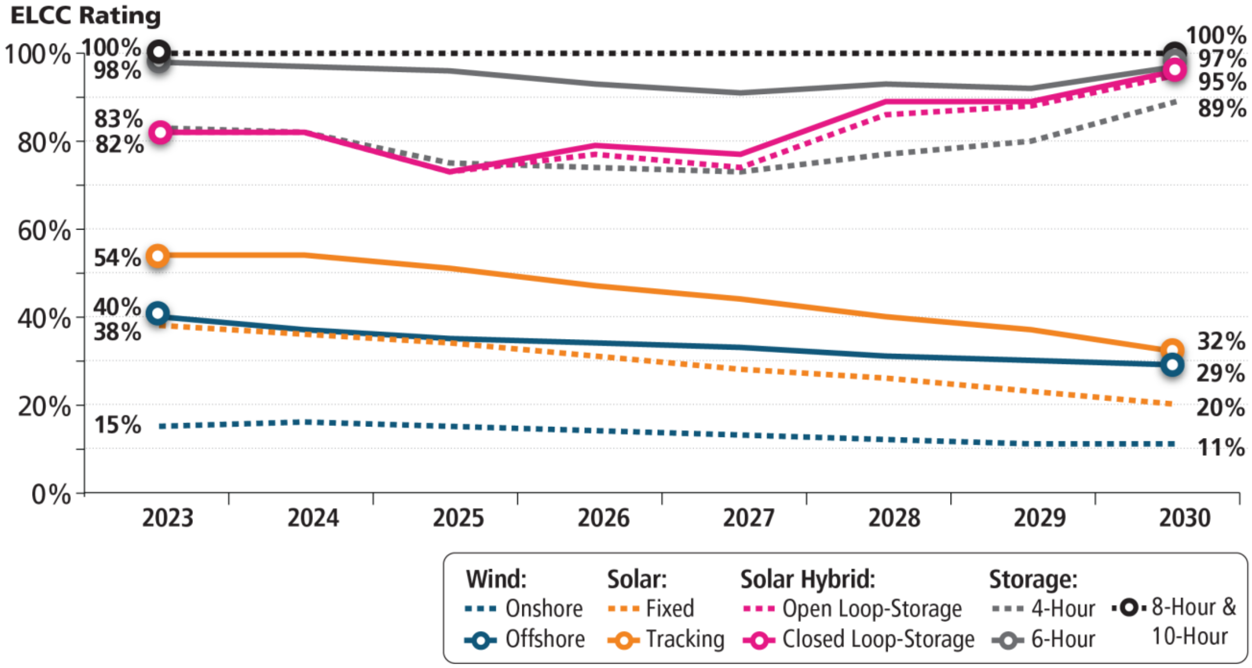
In July 2021, FERC accepted PJM's ELCC methodology for calculating unforced capacity values for intermittent and energy storage capacity resource classes. The ELCC analysis[21] examines load and resource performance uncertainty, and calculates an hourly loss-of-load probability (LOLP) to meet a one-in-10 year loss of load expectation (LOLE) adequacy criteria. The ELCC method examines the alignment of a given resource type's capacity to high risk hours, as well as the change in risk hours proportional to the changes in portfolio size. The adjustments to accredited capacity went into effect in the 2023/2024 BRA executed in June 2022.

This study examined the current renewable generation fleet for the impact of future changes in capacity accreditation. Today, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the RPM capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline by 1.2 GW to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources.[22] This adjustment is consistent with the renewable expectations presented in the December 2021 Effective Load Carrying Capability (ELCC) Report.

[21] Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

[22] Approximate nameplate needed to replace 1 MW of thermal generation: Solar – 5.2 MW; Onshore Wind – 14.0 MW; Offshore Wind – 3.9 MW. These are average values.

Figure 5. Effective Load Carrying Capability (ELCC) Rating by Resource Type



Demand Expectations

Load forecasting is an important part of maintaining the reliability of the bulk electric system. Forecasting helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. PJM's Resource Adequacy Planning Department publishes an annual Load Forecast Report, which outlines "long-term load forecasts of peak-loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage."

Along with the energy transition, PJM is witnessing a large growth in data center activity. Importantly, the PJM footprint is home to Data Center Alley in Loudoun County, Virginia, the largest concentration of data centers in the world.[23] PJM uses the Load Analysis Subcommittee (LAS) to perform technical analysis to coordinate information related to the forecast of electrical peak demand. In 2022, the LAS began a review of data center load growth and identified growth rates over 300% in some instances.[24] The 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth, as shown in **Figure 5**.

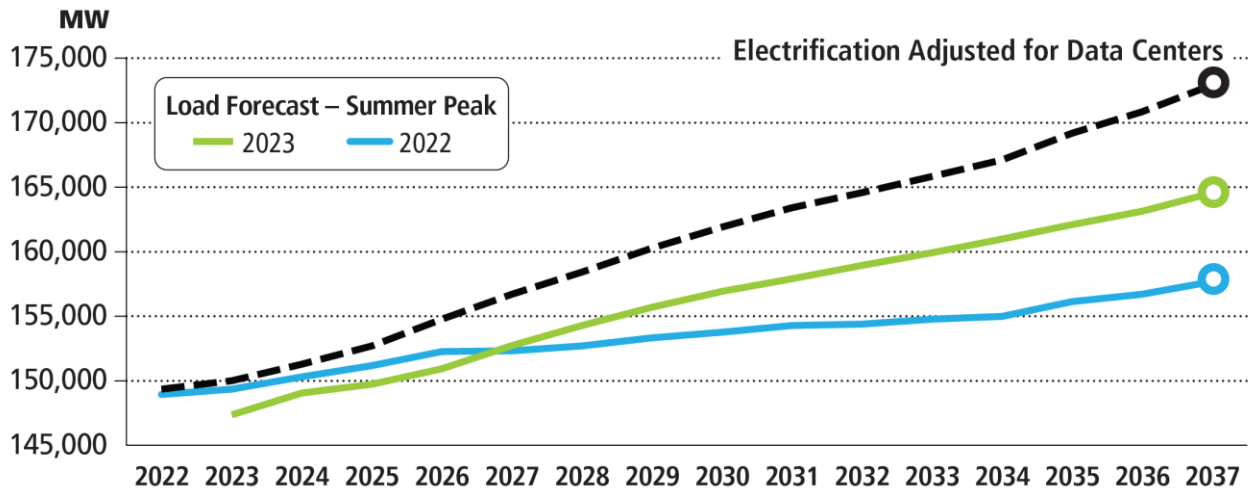
[23] See Loudoun County Department of Economic Development, 2023.

[24] Load Analysis Subcommittee: Load Forecast Adjustment Requests, Andrew Gledhill, Resource Adequacy Planning, Oct. 27, 2022

Additionally, PJM is expecting an increase in electrification resulting from state and federal policies and regulations. The study therefore incorporates an electrification scenario in the load forecast to provide insight on capacity need should accelerated electrification drive demand increases.[25] This accelerated demand increase is consistent with the methodology used in the Emerging Characteristics of a Decarbonizing Grid paper.[26] That paper found electrification to have an asymmetrical impact on demand growth, with demand growth in the winter, mainly due to heating, more than doubling that in the summer. This would move the bulk of the resource adequacy risk from the summer to the winter.

Figure 6 highlights how updated electrification assumptions and accounting for new data center loads have impacted the summer peak between the 2022 and 2023 forecasts.[27]

Figure 6. Impacts of Electrification and Data Center Load on Forecasts



What Does This Mean for Resource Adequacy in PJM?

PJM projects resource adequacy needs through the Reserve Requirement Study (RRS). The purpose of the RRS is to determine the required capacity or Forecast Pool Requirement for future years or delivery years based on load and supply uncertainty. The RRS also satisfies the North America Electric Reliability Corporation/ReliabilityFirst Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation, which requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a LOLE of one occurrence in 10 years. The RRS establishes the Installed Reserve Margin values for future delivery years. For this study PJM used the most recent 2022 RRS, as well as the 2021 RRS for comparison.

[25] Electrification assumptions are 17 million EVs, 11 million heat pumps, 20 million water heaters, 19 million cooktops in PJM by 2037, built on top of the 2022 Load Forecast.

[26] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

[27] 2023 Load Forecast Supplement, PJM Resource Adequacy Planning Department, January 2023.

Combining the resource exit, entry and increases in demand, summarized in **Figure 7**, the study identified some areas of concern. Approximately 40 GW PJM's fossil fuel fleet resources may be pressured to retire as load grows into the 2026/2027 Delivery Year. At current low rates of renewable entry, the projected reserve margin would be 15%, as shown in **Table 1**. The projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations, unless new entry progresses at a levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry

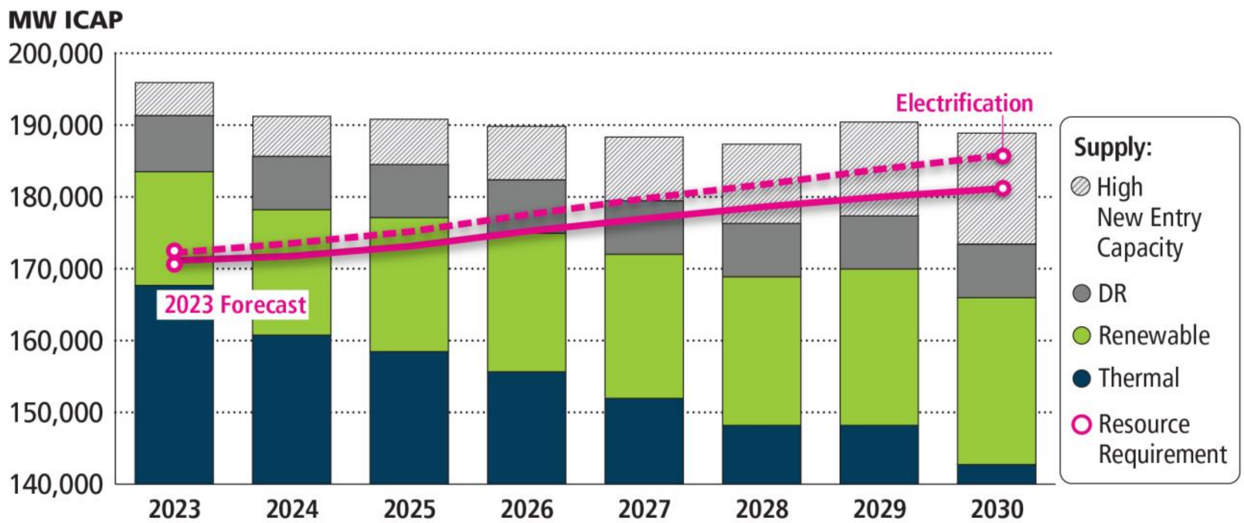
Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

As witnessed during the rapid transition from coal resources to natural gas resources last decade, PJM markets provide incentives for capacity resources. The challenge will be integrating the level of additional resources envisioned to meet this demand, and therefore addressing issues such as resource capacity accreditation is critical in the near term. The low entry rates shown in our Low New Entry scenario are illustrative of recent completion history applied to the current queue. RTO capacity prices in recent auctions have been low for several delivery years, and capacity margins have historically reached around 28% of peak loads. As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs.

The 2024/2025 BRA, which executed in December 2022, highlighted another area of uncertainty. Queue capacity with approved ISAs/WMPAs is currently very high, approximately 35 GW-nameplate, but resources are not progressing into construction. There has only been about 10 GW-nameplate moving to in service in the past three years. There may still be risks to new entry, such as semiconductor supply chain disruptions or pipeline supply restrictions, which are preventing construction despite resources successfully navigating the queue process.

Figure 7. The Balance Sheet



For the first time in recent history, PJM could face decreasing reserve margins, as shown in **Table 1**, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, CAPSTF, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy.

The potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system. Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.

Attachment KMM-3

Via Electronic Delivery

February 24, 2023

Dear PJM Stakeholders,

The PJM Board of Managers (PJM Board) has been closely following the industrywide discussion regarding the maintenance of reliability through the energy transition. There are numerous data points suggesting that grid operators may face challenges in maintaining reliability during the transition. Some examples include:

- The 2022 State of Reliability Report issued by the North American Electric Reliability Corporation in July 2022[1,2]
- The Federal Energy Regulatory Commission's (FERC) docket on Modernizing Electricity Market Design recognizing operational challenges resulting from a changing supply resource mix and the electrification of load, and the comments filed therein from other grid operators[3]
- The October 2022 PJM General Session panel focused on maintaining reliability through the energy transition[4]
- PJM's analysis of generators at risk of retirement titled, "Energy Transition in PJM: Resource Retirements, Replacements and Risks"[5]

While PJM currently has a healthy reserve margin, Winter Storm Elliott demonstrated that PJM is not immune to reliability challenges as the system was stressed, even with a reserve margin in excess of the target and a lower level of renewable penetration than other regions. Although PJM and our members maintained grid reliability throughout Winter Storm Elliott, we believe this event demonstrates a need to focus on PJM's rules and processes to ensure reliability is maintained both now and throughout the transition.

Furthermore, we believe the healthy reserve margins we enjoy now cannot be taken for granted into the future. Energy policies and market forces already have, and could further expedite, the retirement of existing generation resources faster than new resources are able to come online. PJM's analysis in its recent report, "Energy Transition in PJM: Resource Retirements, Replacements and Risks," indicates that there is up to 40 GW at risk of retirement from economic and policy drivers by 2030. The report also highlights significant uncertainty around the pace of resource additions, which at current completion rates would be inadequate to maintain resource adequacy. The

[1] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf
[2] Infographic from 2022 NERC State of Reliability Report – https://www.nerc.com/news/Headlines%20DL/NERC_Infographic_SOR_2022.pdf
[3] https://www.ferc.gov/media/ad21-10-000-0
[4] https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/general-session/2022/20221025/agenda.ashx
[5] https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

potential also exists for significant load growth in the future, driven by data center additions and electrification of transportation, heating and industry.

The Board acknowledges that stakeholders have already initiated work in several of these areas and appreciates your efforts in beginning to tackle these necessary enhancements. Notably, the stakeholder consensus package on interconnection reform that was recently approved by FERC will be critical to increasing the rate at which projects can move through the queue. The Resource Adequacy Senior Task Force (RASTF) is another example of the work currently underway and has resulted in additional initiatives. These initiatives include the Operating Committee's work on reliability attribute identification and definition and the commencement of the Clean Attribute Procurement Senior Task Force (CAPSTF) to focus on the regional procurement of clean attributes.

Notwithstanding the efforts to date, given recent events and analyses, the Board believes near-term changes to the Reliability Pricing Model (RPM) are necessary to ensure that PJM can maintain resource adequacy into the future. The Board also continues to value robust stakeholder review, input and challenge to help solve complex problems such as this. To this end, we have decided to implement the Critical Issue Fast Path (CIFP) accelerated stakeholder process mechanism to further pursue stakeholder consensus that would inform a PJM Board decision on a potential FERC filing targeted for October 1, 2023.

As part of the initiation of the CIFP, the Board is required to identify the scope of the initiative. While the scope and complexity of the issues in the RASTF are significant, the Board's primary focus in this effort is to resolve key issues that we believe would have a direct benefit to reliability. The Board is certainly open to considering holistic proposals containing any items of scope in the RASTF on which stakeholders are able to reach consensus within the time frame of this CIFP process, but requests that stakeholder proposals include improvements in the following key capacity market areas:

1. **Enhanced risk modeling.** In particular, the Board would like to improve the way PJM accounts for winter risk and correlated outages in its reliability planning.

2. **Evaluation of potential modifications to the Capacity Performance construct and alignment of permitted offers to the risk taken by suppliers.** The Board believes that it is appropriate to evaluate whether changes are needed to the Capacity Performance construct and to ensure that market sellers are able to reflect the risk of taking on a capacity obligation in their capacity market offers.

3. **Improved accreditation.** The Board believes that it is necessary to enhance PJM's accreditation approach to ensure that the reliability contribution of each resource is accurately determined and aligned with compensation.

4. **Synchronization between the RPM and Fixed Resource Requirement (FRR) rules.** The Board would like any changes in RPM rules to also be mapped to FRR rules to ensure that supply resources and consumers are held to comparable standards.

The Board believes enhancements in these areas are necessary to improve the operation of the capacity market; however, in recognition of the interrelated nature of many topics within the RASTF's scope, the Board recognizes that topics such as the reliability metric, winterization or firm fuel requirements for capacity resources and rules regarding performance assessments, and others, could be related to the listed scope above and therefore may be a part of a solution.

The Board notes that FERC, in its recent Order approving the 2024/25 Base Residual Auction[6], has indicated its intent to hold a forum in the near future "to examine the PJM capacity market and how best to ensure that it achieves its objective of ensuring resource adequacy at just and reasonable rates."

The Board welcomes the FERC forum and believes that, if anything, the Commission's interest in these larger issues provides further support for use of the CIFP process so that potential solutions can begin to be vetted and then presented to the Commission.

Separate from concerns about resource adequacy, the Board continues to believe in the importance of a well-thought-out Circuit Breaker mechanism that allows the market to function as intended but provides the options to address the risks associated with scarcity pricing for extended periods of time in extraordinary circumstances. We appreciate stakeholder efforts to date to reach consensus on a Circuit Breaker mechanism, as well as the efforts to reach consensus on a package that included the Circuit Breaker and Market Seller Offer Cap. The Board would like to continue efforts to reach resolution in this area and will provide more information on this topic in the near future.

The Board is also considering whether the aforementioned capacity market enhancements should apply to auctions earlier than the 2027/2028 Base Residual Auction as targeted by the RASTF Issue Charge. The Board recognizes that this may require a delay to future auctions and has therefore directed PJM to put together possible alternative auction schedules and discuss them with stakeholders for feedback.

While resource adequacy is a critical component of reliability, the Board believes that there may be other areas of PJM's rules and process that would benefit from review and enhancement to ensure they are working efficiently to maintain reliability at the lowest reasonable cost. The Board looks forward to engaging with stakeholders on these issues in an open and transparent manner and finding the best solutions. Thank you for your continued participation in our robust stakeholder process.

Sincerely,

Mark Takahashi
Chair, PJM Board of Managers

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[6] https://www.pjm.com/directory/etariff/FercOrders/6683/20230221-er23-729,%20el23-19.pdf

Attachment KMM-4

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April 11, 2023

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER23-___-000
Section 205 Filing to Delay Upcoming RPM Auctions, Request for Waiver to Amend Pre-Auction Activity Deadlines for Impacted Delivery Years, and Request for Expedited Action

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and part 35 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations,[1] hereby submits for filing proposed revisions to PJM's Open Access Transmission Tariff ("Tariff")[2] to revise the Reliability Pricing Model ("RPM") Auction schedule for the 2025/2026 through the 2028/2029 Delivery Years. If accepted, this will allow all RPM Auctions beginning with the 2025/2026 Delivery Year to be conducted after Commission action on PJM's upcoming filing, currently scheduled to be filed by October 1, 2023, to enhance PJM's capacity market rules. The reform areas that are under consideration by the PJM Board of Managers ("PJM Board"), as informed by the PJM stakeholder process, are designed to proactively address demonstrated reliability concerns in the PJM footprint during the energy transition over the near-term, i.e., through 2030. Given that the purpose of PJM's capacity auctions is to provide long-term price signals to ensure capacity sufficient to maintain resource adequacy at just and reasonable rates, PJM's going forward capacity procurement should be conducted after the Commission has an opportunity to review the enhancements. Accordingly, it is just and reasonable to delay holding RPM Auctions under the current rules, and establish a new RPM Auction schedule upon Commission action on PJM's upcoming enhancement filing. The rationale for this request is set forth below.

PJM requests an effective date of June 10, 2023, which is 60 days from the date of filing. Such an effective date is appropriate because the 2025/2026 Base Residual

[1] 18 C.F.R. part 35.

[2] The Tariff is currently located under PJM's "Intra-PJM Tariffs" eTariff title. *See PJM Interconnection, L.L.C. - Intra-PJM Tariffs*, https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731 (last visited April 10, 2023). Terms not otherwise defined herein shall have the same meaning as set forth in the Tariff, the Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA"), and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement").

Auction (or "BRA") currently is scheduled to open on June 14, 2023. If the Commission does not accept this filing prior to this date, PJM will proceed with the 2025/2026 Base Residual Auction, and all other RPM Auctions for that Delivery Year will remain as currently scheduled.[3]

PJM did not seek stakeholder endorsement of the proposed revisions herein given the limited time before the next scheduled Base Residual Auction (June 14, 2023). Instead, as further discussed below, PJM is submitting this filing pursuant to Tariff, section 9.2(b) and the Consolidated Transmission Owners Agreement ("CTOA"), section 7.5.1(ii). PJM provided the requisite seven day notice and consultation to the PJM Members and Transmission Owners prior to the submittal of this filing.

I. BACKGROUND

A. PJM Will Propose Capacity Market Rule Enhancements to Address Issues Related to the Energy Transition

PJM is undergoing a major transition in its resource mix. PJM examined this transition in its whitepaper *Energy Transition in PJM: Resource Retirements, Replacements & Risk*.[4] The evidence examined shows that lower-carbon intermittent resources are the predominant resource type entering the PJM market,[5] while thermal generation resources are retiring due to a number of economic and policy-driven conditions, including corporate, state, and federal policy requirements, reduced costs and subsidies for non-thermal resources, age-related maintenance costs, environmental standards, and declining energy market revenues.[6]

However, there is potential for a timing mismatch between when the new resources go in service and when segments of the existing generation fleet retire. This mismatch, in combination with expected load growth,[7] potentially threatens PJM's ability to maintain resource adequacy during the near-term energy transition, i.e., through 2030. In addition, these challenges have highlighted the need to ensure that the relative contribution of different resources to meeting system reliability needs are adequately recognized and compensated.

While PJM has adequate reserves at this time, PJM's capacity market is forward looking. Its primary purpose is to send "price signals [to] guid[e] resource entry and

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[3] To that end, PJM is continuing with pre-auction activities associated with the 2025/2026 Base Residual Auction currently scheduled to commence on June 14, 2023.

[4] *See Energy Transition in PJM: Resource Retirements, Replacements & Risk*, PJM Interconnection, L.L.C. (Feb. 24, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx ("Whitepaper").

[5] *See* Whitepaper at 11.

[6] *See id.* at 13.

[7] *See id.*at 14-15.

exit."[8] Therefore, to allow the capacity auction price signal to properly guide such resource mix transition and to maintain an adequate level of generation resources, on February 24, 2023, the PJM Board initiated an accelerated stakeholder process for the purpose of filing with the Commission by October 1, 2023, a suite of capacity market reforms.[9] Specifically, the PJM Board has directed PJM and stakeholders to develop proposals to improve four key aspects of the capacity market:[10]

- enhance risk modeling, e.g., winter risk and correlated outages in reliability planning;
- revise market rules to ensure seller can reflect risk of committing to provide capacity in their capacity market offers;
- enhance capacity accreditation methodologies for all resource types;
- ensure synchronization between PJM's capacity market rules and its Fixed Resource Requirement rules.[11]

The PJM Board "believes enhancements in these areas are necessary to improve the operation of the capacity market," but that does not mean that the other topics PJM and stakeholders have been examining since April 2021 in the Resource Adequacy Senior Task Force may not be included in the upcoming enhancement filing.[12]

PJM and its stakeholders have already embarked on the process for meeting these PJM Board directives in the Critical Issue Fast Path-Resource Adequacy stakeholder process.[13] As directed by the PJM Board, PJM plans to exercise its FPA section 205 rights and file a proposal to enhance the capacity market rules by October 1, 2023.

B. PJM's Current Capacity Market Auction Schedule

In recent years, as a result of various regulatory actions and proceedings, PJM has departed from the Tariff requirement that PJM hold Base Residual Auctions "in the

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[8] *See PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,180, concurring op. (Commissioner Glick) at P 2 (2021).

[9] *See Critical Issue Fast Path – Resource Adequacy*, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/cifp-ra (last visited April 10, 2023).

[10] Letter from Mark Takahashi, Chair of PJM Board of Managers, to PJM Stakeholders, 2 (Feb. 24, 2023), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx ("2/24 Board Letter").

[11] *See* Whitepaper at 2.

[12] 2/24 Board letter at 2.

[13] *See Critical Issue Fast Path – Resource Adequacy*, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/cifp-ra (last visited April 10, 2023).

month of May that is three years prior to the start of such Delivery Year."[14] The auction schedule was most recently modified to accommodate reinstatement of the historical Energy and Ancillary Services Offset.[15] While further delay of the upcoming RPM Auctions is not ideal, continuing to conduct the auctions under the existing rules further exacerbates the challenge of procuring the necessary resources to facilitate the imminent energy transition while maintaining reliability. In short, since the current tariff provisions in the above areas may be unjust and unreasonable and require change, it does not appear reasonable to continue to lock in resources on a forward basis to such provisions, particularly when they exacerbate the reliability issues that PJM has identified. Thus, PJM seeks a modest delay to the upcoming RPM Auctions to allow for necessary and prospective enhancements to the existing capacity market rules.

To get back on track as expeditiously as possible with minimal disruption to the ability of Base Residual Auctions while securing capacity commitments sufficient to maintain reliability at just and reasonable rates, PJM generally has been holding Base Residual Auctions on a "once-every-six months" schedule. The current RPM Auctions schedule is shown below in Table 1.

Table 1: Current RPM Auction Schedule

Delivery Year	BRA Schedule Date	Incremental Auctions Scheduled
2023/2024	Held June 2022	3rd IA only
2024/2025	Held Dec 2022	3rd IA only
2025/2026	Jun 2023	3rd IA only
2026/2027	Nov 2023	2nd and 3rd IAs only
2027/2028 (back on Tariff schedule)	May 2024	1st, 2nd, and 3rd IAs

II. TARIFF REVISIONS TO DELAY RPM AUCTIONS UNTIL COMMISSION ACTION ON PJM'S UPCOMING CAPACITY MARKET ENHANCEMENTS FILING

To address the reliability concerns that PJM has identified and safeguard reliability during the energy transition over the near-term, i.e., through 2030, upcoming RPM Auctions should be based on capacity market rules enhanced by PJM's forthcoming

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[14] *See PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,153, at P 12 (2018) (waiving PJM's auction schedule requirements while the Commission considered market rule changes); *Calpine Corp. v. PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,061, at P 358 (2020) (waiving PJM Tariff auction schedule requirements to allow for orderly restoration of capacity auction activities).

[15] *See PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,122 (2022) (accepting compliance filing detailing capacity auction schedule, and request for waiver, to accommodate reinstatement of historical energy and ancillary services offset).

filing. Accordingly, PJM proposes to delay upcoming Base Residual Auctions and associated Incremental Auctions until after the Commission acts on such filing.[16] While these capacity market reforms will likely be filed before October 1, 2023, the Base Residual Auction for the 2025/2026 Delivery Year is currently scheduled to commence on June 14, 2023, and the Base Residual Auction for the 2026/2027 Delivery Year is scheduled to commence on November 28, 2023.[17] Thus, delay of such auctions is required to ensure that PJM's forward capacity market continues to promote reliability assurance in the PJM Region.

However, to accommodate the delay of these two auctions, PJM also is proposing to delay the two subsequent BRAs, i.e., through the 2028/2029 Delivery Year. Table 2 below presents an illustrative revised auction schedules for the subsequent RPM Auctions through the 2028/2029 Delivery Year. The timelines are illustrative because they assume a Commission order, without material changes on compliance, by December 1, 2023. These timelines could shift if the Commission deems that additional filings are required in reviewing PJM's forthcoming capacity market reforms.[18]

Table 2: Illustrative RPM Auction Schedule[19]

Delivery Year	Illustrative BRA Schedule	Incremental Auctions Scheduled	IAs Cancelled
2025/2026	Jun 2024	3rd IA	1st and 2nd IAs
2026/2027	Dec 2024	3rd IA	1st and 2nd IAs
2027/2028	Jun 2025	2nd and 3rd IAs	1st IA
2028/2029	Dec 2025	2nd and 3rd IAs	1st IA
2029/2030 (back on Tariff schedule)	May 2026	1st, 2nd, and 3rd IA	None

Thus, the Base Residual Auction for the 2025/2026 Delivery Year likely would be delayed by about a year. While pre-auction activities for the 2025/2026 Base Residual Auction have started, and will continue, upon Commission acceptance of this filing, PJM proposes to void such ongoing activities and start the process over again in advance of a

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[16] PJM's proposal does not affect the currently scheduled Third Incremental Auctions for the 2024/2025 Delivery Year.

[17] *RPM Auction Schedule*, PJM Interconnection, L.L.C. (Feb. 28, 2023), https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx (follow to sheet "Opening Dates through 2026/2027").

[18] PJM is cognizant of the possibility that additional Delivery Years may also be impacted if a workable FERC order is not issued by the end of 2023. If such an event arises, PJM would address the need for any further auction schedule updates within the resource adequacy reform proceeding.

[19] This schedule is wholly illustrative and assumes Commission action, with no material compliance filings, by December 1, 2023.

future auction for that Delivery Year. Restarting the process is reasonable given that the one-year delay in holding the 2025/2026 Base Residual Auction will render the current pre-auction activities outdated, both in terms of staleness and applicability under the enhanced rules.[20]

As can be seen from the illustrative dates in Table 2, PJM proposes to maintain the shortened RPM Auction timeframes through the 2028/2029 Delivery Year. That is, PJM would continue its current practice of scheduling Base Residual Auctions at six-month intervals. To be clear, given that the actual schedule of the auction will depend on when FERC issues a workable order on PJM's forthcoming capacity market reform filing, PJM is not specifying the auction dates in the Tariff. Rather, PJM will post the auction schedule consistent with the process described herein once the Commission issues an order on PJM's forthcoming capacity reform filing.

Given that the Base Residual Auctions for these Delivery Years will be held closer than three years to the Delivery Year, the question arises of whether there is sufficient time to hold each of the three Incremental Auctions for a Delivery Year. Because a primary purpose of Incremental Auctions is to align capacity commitments with expected load demands, PJM proposes to continue its current practice of: (1) maintaining all Third Incremental Auctions for each Delivery Year; (2) cancelling Incremental Auctions that fall within 10 months of the associated Base Residual Auction; and (3) to the extent practicable, applying the Tariff rules for holding the First, Second, and Third Incremental Auctions.[21] In short, "PJM reasonably proposes to eliminate certain additional incremental auctions, using the same guiding principles previously accepted by the Commission."[22]

Applying these guiding principles, PJM would maintain all Third Incremental Auctions for each Delivery Year, and hold those auctions in the February prior to the Delivery Year.[23] The specific First and Second Incremental Auctions that will be canceled depend on the timing of the Commission's order on PJM's forthcoming resource adequacy reforms. It is reasonable to cancel those Incremental Auctions that are within 10 months of a Base Residual Auction in these limited Delivery Years because there would be little, if any, need for such auctions under a compressed Base Residual Auction schedule as very little time would pass between the Base Residual Auction and Incremental Auctions. Moreover, Market Participants will always have the opportunity to buy back and offer additional capacity in the Third Incremental Auction before the

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[20] Further, any agreements reached between the Capacity Market Seller and PJM resolving any issues related to the pre-auction activities may not be relied on for a future 2025/2026 Base Residual Auction.

[21] *See* Tariff, Attachment DD, section 5.4(b) (detailing the requirements for when First, Second, and Third Incremental Auctions must be held).

[22] *PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,122, at P 15 (2022) (citing *Calpine*, 173 FERC ¶ 61,061, at P 358).

[23] *See* Tariff, Attachment DD, section 5.4(b).

start of the Delivery Year under this proposal. This is the same approach that PJM previously proposed and the Commission accepted for prior RPM Auction delays.

Under the illustrative schedule in Table 2, PJM would maintain the Second Incremental Auctions for the 2027/28 and 2028/2029 Delivery Years, as the Base Residual Auctions for those Delivery Years would be held more than ten months before the "July that is ten months prior to the start of the Delivery Year."[24] However, the First Incremental Auction for all four Delivery Years with delayed Base Residual Auctions would be cancelled, because such Incremental Auctions would be held "within 10 months of the associated Base Residual Auction."[25] The logic of this accepted principle is that insufficient time has passed since the Base Residual Auction for the Incremental Auction to have meaning—e.g., there should be time for load forecasts to be re-visited based on updated data.

This deliberate and timely schedule: (1) allows a reasonable initial period for market participants to assess the results of the prior Base Residual Auction or assess the Commission's action; (2) allows sufficient time (albeit slightly compressed from the standard schedule) to conduct pre-auction activities (discussed in Part III below); and (3) puts the PJM Region on track to return to the designed three-year forward BRA schedule in the least time consistent with an orderly process. Moreover, PJM and stakeholders have found that this timeframe allows for a compressed pre-auction timeline while also providing a reasonable amount of time for Market Participants to assess the BRA results before preparing for subsequent BRAs.

To effectuate the delay of these RPM Auctions and because PJM's Tariff hardcodes that Base Residual Auctions and Incremental Auctions must be held in certain timeframes before the Delivery Year,[26] PJM proposes to add language to its Tariff allowing for the delay of these RPM Auctions for the Delivery Years 2025/2026 through 2028/2029. However, PJM cannot now know the precise timing of Commission action on the upcoming capacity market reform enhancement filing. Therefore, PJM is proposing to revise its Tariff to provide that "for Delivery Years 2025/2026 through 2028/2029, the Base Residual Auctions shall be conducted in accordance with the schedule posted on the PJM website,"[27] and correspondingly, that "for Delivery Years 2025/2026 through 2028/2029, the Incremental Auctions shall be conducted in accordance with the schedule posted on the PJM website."[28]

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[24] Tariff, Attachment DD, section 5.4(b).

[25] The Tariff calls for First Incremental Auction to be "conducted in the month of September that is twenty months prior to the start of the Delivery Year." Tariff, Attachment DD, section 5.4(b).

[26] *See* Tariff, Attachment DD, section 5.4(a) and (b).

[27] Proposed Tariff, Attachment DD, section 5.4(a).

[28] Proposed Tariff, Attachment DD, section 5.4(b).

PJM's approach of awaiting Commission action on the capacity market enhancements is reasonable. Capacity Market Sellers should know before they make concrete auction preparations, for example, whether the Commission accepts an enhanced capacity accreditation methodology that affects the amount of capacity their resources may support or whether they may price certain risks of providing capacity into their offers—just to name a couple potential enhancements. Therefore, PJM proposes that the date for these RPM Auctions be keyed from the date of the Commission's order on PJM's upcoming filing. Finally, consistent with prior practice, PJM would post the specific auction date and associated pre-auction timelines at least eight months before the commencement of the relevant RPM Auction.[29]

III. REQUEST FOR WAIVER OF THE TARIFF-STATED DEADLINES FOR CERTAIN PRE-AUCTION ACTIVITIES IN ORDER TO EFFECTUATE DELAY IN THE RPM AUCTION SCHEDULE

If the Commission accepts PJM's proposed Tariff revisions to delay the RPM Auctions for Delivery Years 2025/2026 through 2028/2029, the Tariff-prescribed deadlines for pre-auction activities for such Base Residual Auctions and Incremental Auctions must also be changed because of the condensed timeframe in which those auctions must be held, i.e., every six months, instead of once a year three years before the Delivery Year. Accordingly, PJM requests waiver of the Tariff provisions—listed in Attachment A to this filing[30]—on Base Residual Auction and Incremental Auction pre-auction activity deadlines.[31] PJM's requested deadlines retain the pre-auction timelines for delayed RPM Auctions that the Commission has previously accepted and simply extends out the previously accepted compressed pre-auction deadlines through the 2028/2029 Delivery Year.[32]

The Commission has previously granted requests for waiver of Tariff-specified pre-auction deadlines under the familiar four-part framework when "(1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete

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[29] *Calpine*, 173 FERC ¶ 61,061, at P 358.

[30] In addition, PJM proposes to maintain its existing discretion to set the actual deadline within 10 business days from the timelines provided herein. *See PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,122, at P 15 ("We also find reasonable PJM's proposal to retain limited discretion of up to 10 business days to set the specific deadlines associated with any pre-auction activities. We agree with PJM that it would be cumbersome and administratively inefficient to seek further amendments to the auction timelines for minor adjustments to the deadlines. However, we recognize PJM's commitment to post the specific dates of pre-auction activities no later than eight months prior to the commencement of any associated BRA in order to ensure that all market participants are aware of the relevant deadlines.").

[31] As noted above, all pre-auction activities for the 2025/2056 Base Residual Auction would need to be restarted, based on the rules in effect at that time and updated information, and any agreements reached with PJM heading into a June 2023 auction would not apply to a future auction for that Delivery Year.

[32] *Compare* Attachment A, *with* Compliance Filing Concerning Certain Proposed Revised Pre-Auction Deadlines, Docket No. EL19-58-010, at Attachment C (Jan. 21, 2022).

problem; and (4) the waiver does not have undesirable consequences, such as harming third parties."[33] PJM's waiver request here meets these requirements.

PJM has acted in good faith. The consequences of conducting auctions—committing resources to the region's capacity needs and determining clearing prices and results—are the same consequences of conducting all past RPM Auctions. The potential for mismatch between resource retirement and new resources coming online, plus expected load growth, exposes the PJM Region to resource shortfall risks if certain market enhancements are not enacted. While PJM is actively and diligently working with stakeholders to develop such enhancements, the process will not yield a filing for Commission review until around October 1, 2023.

The problem is concrete, i.e., delaying RPM Auctions until the Commission action on PJM's enhancement filing; and the scope is no greater than is needed to comport certain pre-auction deadlines to fit within the revised auction schedule.[34] Indeed, the pre-auction schedule for each Base Residual Auction is compressed, but not in a major way, as parties in the last two Base Residual Auctions have had sufficient time to make their pre-auction arrangements.

Grant of the waiver will not have undesirable consequences. In fact, to the extent the Commission accepts the proposed Tariff changes, the request waiver is needed to effectuate the delay. In other words, the pre-auction activities must be compressed to allow for the scheduling of the Base Residual Auctions at six-month intervals. Further, there was be no reason to conduct pre-auction activities based on the existing Tariff deadlines if there are no scheduled auctions as a result of the delay. In short, granting the waiver of those Tariff-specified deadlines is reasonable as there is no harm to third parties for updating pre-auction deadlines to simply conform with the delayed RPM Auctions if accepted by FERC pursuant to FPA section 205.

IV. REQUEST FOR EXPEDIATED ACTION

To provide as much advanced notice to Market Participants as possible, PJM requests that the Commission expedite an order on this filing so that Market Participants and PJM know whether to continue with the ongoing pre-auction activities associated with the upcoming 2024/2025 Base Residual Auction. Such expedited action by May 19, 2023, will help PJM and Market Participants focus on the forthcoming resource adequacy enhancements rather than continuing to prepare for the 2024/2025 Base Residual Auction if it is not delayed and commences on June 14, 2023. To that end, the

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[33] *PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,153, at P 12 (2018) (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059, at P 14 (2016); *Calpine Energy Servs., L.P.*, 154 FERC ¶ 61,082, at P 12 (2016); *N.Y. Power Auth.*, 152 FERC ¶ 61,058, at P 22 (2015)); *see also Calpine*, 173 FERC ¶ 61,061, at P 358.

[34] *See Calpine*, 173 FERC ¶ 61,061, at P 359 ("[W]e find that the request is of limited scope, because it will alter deadlines only for the auctions which have been impacted by the delay of the 2019 BRA.").

Commission should set a comment period that it deems is appropriate to allow for expedited action.

V. STAKEHOLDER PROCESS

As noted, *supra*, given the limited time before the next scheduled Base Residual Auction (June 14, 2023), PJM did not seek stakeholder endorsement prior to submitting this proposed revision and is instead submitting this filing pursuant to Tariff, section 9.2(b) and the CTOA, section 7.5.1(ii). Consistent with those provisions, PJM provided seven days prior notice to the Members Committee and the Transmission Owners Committee of the proposed revisions on January 25, 2023 and January 26, 2023, respectively.[35] Accordingly, PJM fulfilled its consultation obligations under the Tariff and CTOA prior to the submission of this section 205 filing.

VI. EFFECTIVE DATE

PJM requests an effective date for the enclosed Tariff revisions of June 10, 2023, which is 60 days from the date of filing.

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[35] *See* Members Committee, *Agenda*, PJM Interconnection, L.L.C. (Jan. 23, 2023), https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20230125/20230125-agenda.ashx; *see also PJM TOA-AC Open Session Agenda*, PJM Interconnection, L.L.C. (Jan. 26, 2023) https://www.pjm.com/-/media/committees-groups/committees/toa-ac/2023/20230126/agenda.ashx.

VII. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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VIII. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;

2. Schedule of Pre-Auction Activities Deadlines (as Attachment A); and

3. Revisions to the Tariff (in redlined and clean format (as Attachments B and C, respectively) and in electronic tariff filing format as required by Order No. 714).[36]

IX. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[37] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order with a specific link to the newly-filed

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[36] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

[37] *See* 18 C.F.R. §§ 35.2(e) & 385.2010(f)(3).

document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region[38] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.aspx in accordance with the Commission's regulations and Order No. 714.

X. CONCLUSION

Accordingly, PJM requests that the Commission accept the enclosed Tariff revisions effective June 10, 2023, and grant PJM's request for waiver of certain Tariff-specified pre-auction deadlines.

Respectfully submitted,

/s/ Ryan J. Collins

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April 11, 2023

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[38] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

Attachment A

RPM Pre-Auction Deadlines
For the 2025/2026 through 2028/2029 Delivery Years

"Adjusted Days Prior" refer to PJM's requested modified deadline for the corresponding activity prior to the relevant BRA.

"Deadline" refers to the current Tariff imposed deadlines for the corresponding activity.

Actor	**Pre-Auction Task or Activity**	**Deadline, with Tariff Source**	**Adjusted Days Prior**[1]
Seller	MOPR Certification	150 days prior to BRA beginning with 2024/2025 BRA (Tariff, Attachment DD section 5.14)	150
PJM	PJM solicits requests for Winter CIRs	Aug. 31 of each calendar year (Tariff, Attachment IV Preamble)	145
Seller	Seller Final Must-Offer exception request (Deactivation)	Dec. 1 prior to BRA (Tariff, Attachment DD section 6.6)	135
PJM	PJM posts DR Zones of Concern	Dec. 1 prior to BRA (Tariff, Attachment DD-1)	135

[1] PJM proposes to maintain its existing discretion to set the actual deadline within 10 business days from the timelines provided herein. *See PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,122, at P 15 (2022) ("We also find reasonable PJM's proposal to retain limited discretion of up to 10 business days to set the specific deadlines associated with any pre-auction activities. We agree with PJM that it would be cumbersome and administratively inefficient to seek further amendments to the auction timelines for minor adjustments to the deadlines.").

Actor	Pre-Auction Task or Activity	Deadline, with Tariff Source	Adjusted Days Prior[1]
Seller	Seller Preliminary Must-Offer exception request (Deactivation)	Sept. 1 prior to BRA (Tariff, Attachment DD, section 6.6)	waived
Seller	Seller request for Winter CIRs	Oct. 31 prior to BRA (Tariff, IV Preamble)	135
PJM/ Market Monitor	PJM Posts Preliminary MOPR Screen Prices and Market Monitor Posts Preliminary Unit-Specific E&AS Offset	150 and 90 days, respectively, prior to auction (Tariff, Attachments DD section 5.14 and M-Appendix, section I.)	150
Market Monitor	Market Monitor Posts Final Unit-Specific E&AS Offset	90 days prior to auction (Tariff, Attachment M-Appendix, section I.)	135
FRR Entity	FRR first-time election	4 months prior to BRA (RAA, Schedule 8.1.C)	121
Seller	Seller unit-specific MOPR request	120 days prior to BRA (Tariff, Attachment DD section 5.14)	120
Seller	Seller unit-specific request (Must-Offer, Offer Cap, EFORd, Removal of Capacity Resource status)	120 days prior to auction (Tariff, Attachment DD, section 6.6)	120
Seller	Submission of Price Responsive Demand Plans	Jan. 15 prior to BRA (RAA, Schedule 6.1)	117
PJM	PJM posts Planning Parameters	Feb. 1 prior to BRA (M18; Tariff, Attachment DD, section 15)	100
Market Monitor	Market Monitor Determination (MOPR)	90 days prior to auction (Tariff, Attachment M – Appendix)	90
Market Monitor	Market Monitor Determination (Must-Offer, Offer Cap, EFORd)	90 days prior to auction (Tariff, Attachment M – Appendix)	90
Seller	Seller Notification to PJM (Must-Offer, Offer Cap, EFORd)	80 days prior to auction (Tariff, Attachment DD, sections 5.14 & 6.6)	80

Actor	Pre-Auction Task or Activity	Deadline, with Tariff Source	Adjusted Days Prior[1]
PJM	PJM Determination (MOPR)	65 days prior to auction (Tariff, Attachment DD section 5.14)	65
PJM	PJM Determination (Must-Offer, Offer Cap, EFORd)	65 days prior to auction (Tariff, Attachment DD sections 5.14 & 6.6)	65
Seller	Seller Notification of intent to exclude Must-Offer Exception MW	65 days prior to auction (Tariff, Attachment DD section 6.6)	65
FRR Entity	FRR termination of election	2 months prior to BRA (RAA, Schedule 8.1.C)	61
Seller	Seller Confirmation of MOPR price	60 days prior to auction (Tariff, Attachment DD section 5.14)	60
FRR Entity	FRR DR Plan	15 business days prior to FRR Plan (Tariff, Attachment DD-1)	49
Seller	Seller needs ICTR/QTU certification of CETL increase	45 days prior to BRA (Tariff, Attachment DD section 5.6.4)	45
FRR Entity	FRR Capacity Plan	1 month prior to BRA (RAA, Schedule 8.1.C)	30
Seller	Submission of Energy Efficiency Plan	30 days prior to auction (Tariff, Attachment DD-1)	30
Seller	Submission of Demand Resource Plan	30 business days prior to auction (Tariff, Attachment DD-1)	30

Attachment B

Revisions to the
PJM Open Access Transmission Tariff

(Marked/Redline Format)

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, for Delivery Years 2025/2026 through 2028/2029, the Base Residual Auctions shall be conducted in accordance with the schedule posted on the PJM website. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for Delivery Years 2025/2026 through 2028/2029, the Incremental Auctions shall be conducted in accordance with the schedule posted on the PJM website.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

Attachment C

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, for Delivery Years 2025/2026 through 2028/2029, the Base Residual Auctions shall be conducted in accordance with the schedule posted on the PJM website. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for Delivery Years 2025/2026 through 2028/2029, the Incremental Auctions shall be conducted in accordance with the schedule posted on the PJM website.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

FERC rendition of the electronically filed tariff records in Docket No. ER23-01609-000
Filing Data:
CID: C000030
Filing Title: Delay Upcoming RPM Auctions, Requests for Waiver and Expedited Action
Company Filing Identifier: 8831
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: Intra-PJM Tariffs
Tariff ID: 23
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
ATTACHMENT DD.5.4, OATT ATTACHMENT DD.5.4 Reliability Pricing Model Auctions, 8.0.0, A
Record Narative Name: 5.4 Reliability Pricing Model Auctions
Tariff Record ID: 1147
Tariff Record Collation Value: 661040069   Tariff Record Parent Identifier: 1142
Proposed Date: 2023-06-10
Priority Order: 500
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

5.4 Reliability Pricing Model Auctions

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Document Content(s)

Attachment KMM-5

U.S. Department of Energy and Environmental Protection Agency Partner to Support Reliable Electricity

New Memorandum of Understanding Supports Reliability of Nation's Power System as Energy Sector Invests in Clean Energy Opportunities

March 9, 2023

Contact Information
EPA Press Office (press@epa.gov)

DOE Press Office (DOEnews@hq.doe.gov)

WASHINGTON — The U.S. Department of Energy (DOE) and U.S. Environmental Protection Agency (EPA) today signed a Joint Memorandum of Understanding (MOU) <https://epa.gov/power-sector/electric-reliability-mou> to guide new clean energy opportunities that will support access to reliable, affordable electricity and advance the United States toward the Biden-Harris Administration's goal of a net-zero economy by 2050. With the power sector facing rising challenges to reliability—from the increasing frequency of extreme weather events to higher energy demand—this agreement provides a framework for both agencies to unlock the reliability advantages of the growing clean energy economy.

"The clean energy transition is an amazing opportunity to add a diverse range of energy sources to our power systems, making them more resilient and reliable," **said U.S. Secretary of Energy Jennifer M. Granholm**. "I am proud that DOE and EPA are partnering together with industry and communities to help equip the grid to deliver affordable, clean electricity to all Americans."

"A reliable electric power system is essential to our national security, continued economic growth and the protection of public health. That's why DOE and EPA are uniting our long-standing efforts to ensure a robust and resilient system, especially as the power sector accelerates the transition to low- and zero-carbon energy sources," **said EPA Administrator Michael S. Regan**. "Under this partnership with DOE, we will provide needed regulatory certainty and support grid reliability and resiliency at every stage as the agency advances efforts to reduce pollution, protect public health, and deliver environmental and economic benefits for all."

"EEI and our member electric companies are focused on affordability and reliability as we work to get the energy we provide to customers as clean as we can as fast as we can," **said Edison Electric Institute President Tom Kuhn**. "Both the Department of Energy and the Environmental Protection Agency are critical partners in these efforts, and we applaud increased coordination to support the ongoing clean energy transition that electric companies are leading."

“As we have seen in recent years, the reliability of the electric grid is tied directly to the safety and well-being of our communities,” **said National Association of Regulatory Utility Commissioners Executive Director Greg R. White**. “Maintaining electricity system reliability during the transition to cleaner energy is critical to NARUC’s members and is in everyone’s best interest. As such, we applaud the DOE and EPA for taking this initiative.”

“PJM supports the Memorandum of Understanding between EPA and DOE, as well as the close involvement of FERC, in addressing electric sector reliability during the energy transition,” **said PJM Interconnection LLC**. “PJM is grateful for the support for reliability that the DOE and EPA have shown in our ongoing collaboration efforts surrounding the development and implementation of federal policy and regulations.”

“The complex transitions underway in the nation’s electric system can only occur on a foundation of superb reliability,” **said Analysis Group Senior Advisor Dr. Susan Tierney**. “Secretary Granholm and Administrator Regan underscore the importance of this fact in committing DOE and EPA staff to work together as they carry out their old and new authorities to help ready the U.S. power sector for the needs of Americans today and tomorrow.”

The new MOU on Interagency Communication and Consultation on Electric Reliability, signed by Secretary Granholm and Administrator Regan, comes as President Biden’s Bipartisan Infrastructure Law and Inflation Reduction Act provided unprecedented support for American infrastructure, including DOE’s new Grid Deployment Office. It also builds upon longstanding engagement from DOE and EPA with the power sector and further commits the agencies to routine and comprehensive communication about policies, programs, and activities regarding electric reliability. This includes sharing information and analysis, and ongoing monitoring and outreach to key stakeholders to proactively address reliability challenges.

Both agencies have designated a team of experts on electric reliability to serve as points of contact for routine communications across the agencies. In addition, the agencies will meet on an at least semiannual basis to provide updates about policies, programs, and activities pertaining to electric reliability, share information and analysis, and discuss ongoing monitoring and outreach activities.

The United States already has in place a multilayered system of institutions, policies, and practices to ensure that our infrastructure for generating, transmitting, and distributing electric power maintains the highest standards of reliability. The MOU ensures that, with the sound application of existing authorities and policy tools, DOE and EPA can continue to support the ability of the power sector to maintain electric reliability and seize new reliability opportunities presented by clean energy advancement. EPA and DOE anticipate continued consultation with the Federal Energy Regulatory Commission (FERC) on electric reliability challenges.

The MOU will support the work of the two agencies as EPA develops new health and environmental protections for the power sector and as DOE works to implement President Biden's historic investments in America, including resources for clean energy deployment and grid reliability and resilience from the Bipartisan Infrastructure Law and the Inflation Reduction Act.

Attachment KMM-6

Written Testimony of James P. Danly
Commissioner, Federal Energy Regulatory Commission
Before the Committee on Energy & Natural Resources
United States Senate
May 4, 2023

Chairman Manchin, Ranking Member Barrasso, and members of the Committee:

Good morning, it is a pleasure to be here today. I very much appreciate the opportunity to appear before the Committee and welcome the opportunity to share my thoughts and answer your questions. While natural gas and FERC's administration of the Natural Gas Act accounted for most of my comments the last two times I appeared before the Committee, today I would instead like to focus on a different subject—the impending, but avoidable, reliability crisis that will likely result from FERC's maladministration of our wholesale electric markets.

The majority of Americans live in regions served by FERC's electric markets. Those markets, the ISOs and RTOs, are FERC-jurisdictional public utilities responsible for operating the transmission systems within their territories and ensuring the economic dispatch of generation to meet demand. They were originally conceived of as a means by which the ratepayer could reap the benefits of competition by ensuring that the least-cost generating unit would be selected to provide electricity. The markets were also designed to send price signals, typically through periodic auctions, to provide the economic incentives to attract new, needed generation investments and promote the orderly exit of existing generating assets that had become economically unviable. That way, so the thinking went, there would always be sufficient generation available to meet peak demand, and the customers would pay the least cost for the most efficient generating units to obtain their electricity.

That, at least, was the theory. What has happened instead is that FERC has distorted price signals and warped incentives in the markets, interfering with price formation and jeopardizing resource adequacy. Most of these market-distorting forces originate with subsidies—both state and federal—and from public policies that are otherwise designed to promote the deployment of non-dispatchable wind and solar assets or to drive fossil-fuel generators out of business as quickly as possible.

The subsidies available to renewable generators are so lucrative that, when participating in procurement auctions, they are able to offer at a price of zero instead of their actual cost. The market signal thereby created is that these new resources can be built for *free*, and thus the cost of power is also free. This, of course, is untrue, and the inevitable consequence is market-wide price suppression. The price suppression deprives other market participants of much needed revenue, leading to the premature retirement of the dispatchable generators which have to offer into the market at their true costs in order to remain viable.

FERC has seemingly done everything in its power to ensure that our markets will fail. FERC eliminated the market's economic guardrail—the minimum offer price rule—which had been established in certain markets to ensure that all generators offered their actual costs to prohibit price suppression. FERC has also directly interfered with price formation by allowing one of our wholesale markets to change the rules of its procurement auction *after* the auction had run in order to lower the resulting prices.

We know that there is a looming resource adequacy crisis. Our market operators have been explicitly telling us as much for years. Both MISO and ISO-NE have warned about upcoming scarcity and PJM, the nation's largest wholesale market, and the one that serves Washington, D.C., has recently raised the alarm about impending shortfalls. Were any more proof required of our markets' failure, in the midst of PJM's dire warnings, somehow the prices in its procurement auction, at a time of impending scarcity, went *down*.

As an engineering matter, there is no substitute for reliable, dispatchable generation. Intermittent renewable resources like wind and solar are simply incapable, by themselves, of ensuring the stability of the bulk electric system. As the wholesale markets' prices are distorted by subsidies, the generation assets with the attributes required for system stability will retire and system stability will be imperiled. Given these market failures, there will be, in time, a catastrophic reliability event. None of us wants this to happen, and I fervently hope to be proven wrong, but if FERC continues to fail in its duty to ensure proper price formation, that will be the inevitable result.

The consequences of premature retirements and resource scarcity are even more acute when you consider the constraints on natural gas supply resulting from the underdevelopment of interstate natural gas infrastructure—again, driven by the FERC's maladministration of the Natural Gas Act. Although I am genuinely delighted that the Commission has recently increased the pace of natural gas pipeline reviews, the policies FERC recently sought to promulgate have had the very effects I predicted at last year's hearing: according to the Energy Information Administration, 2022 saw the lowest quantity of additional capacity added to the natural gas pipeline system since 1995, the obvious result of the FERC's slow walking natural gas pipeline applications over the last two years and the chilling effect of the regulatory uncertainty created by the Commission's issuances. Interstate natural gas infrastructure is absolutely critical: as coal, nuclear and hydroelectric generators retire due to subsidies and public policy choices, the need for natural gas to ensure system reliability continues to grow.

Our markets are failing, and FERC is not acting to fix them. There is no statutory requirement to have these markets—they are inventions of FERC. Other regions of the country, like the Southeast and Intermountain West, operate along the traditional model of vertically integrated utilities overseen by state public utility commissions. There, the rates are, for the most part, substantially lower than in FERC's vaunted wholesale markets and some of the utilities in those regions have not had to resort to firm load shed since the mid-1970s. I am a free marketeer who believes in the power of market forces, but these markets, hobbled as they are by subsidies and FERC's interference, have been undermined to the point that they cannot be relied upon to ensure just and reasonable rates or provide resource adequacy. Our markets are in dire need of repair; FERC must act before there is a truly catastrophic reliability failure.

Again, thank you for the opportunity to address the Committee. I look forward to your questions.

Attachment KMM-7

Opening Statement of Mark C. Christie
Commissioner
Federal Energy Regulatory Commission (FERC)
Senate Energy and Natural Resources Committee Hearing
May 4, 2023

Chairman Manchin, Ranking Member Barrasso, Members of the Committee.

Thank you once again for the privilege to appear before you with my colleagues from FERC.

The United States is heading for a reliability crisis. I do not use the term "crisis" for melodrama, but because it is an accurate description of what we are facing. I think anyone would regard an increasing threat of system-wide, extensive power outages as a crisis.

In summary, the core problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the *addition* of intermittent resources, primarily wind and solar, but the far too rapid *subtraction* of dispatchable resources, especially coal and gas.

To cite just one example: Just a few weeks ago, Manu Asthana, the CEO of the PJM regional transmission organization – the largest RTO in the country in terms of consumers served -- said that PJM faced the likelihood of losing 40 gigawatts of generation capacity by 2030 through early retirements of generating units. 90% of this retiring capacity is *dispatchable* generation, primarily coal and gas. Meanwhile PJM faces load growth of an additional 13 gigawatts by 2030. The PJM interconnection queue, however, largely consists of *intermittent* generation, primarily wind and solar.[1] In terms of capacity value – which is the amount of power that can be supplied to the grid when needed -- one nameplate megawatt of wind or solar is simply not equal to one nameplate megawatt of gas, coal or nuclear. So even if every unit waiting in the PJM interconnection queue was interconnected, that would not solve the reliability problem caused by too-rapid loss of dispatchable generation. The numbers just do not balance. The PJM CEO warned that PJM needed to slow the pace of generator retirements or face reliability problems.[2]

The same problem of cascading retirements of dispatchable resources is also present in other RTOs. MISO, which serves the Midwest and parts of the Southeast, has also been warning regularly about this coming reliability threat.

The nation's designated reliability experts at the North American Electric Reliability Corporation (NERC) have warned about this threat repeatedly.[3]

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[1] *Energy Transition in PJM: Resource Retirements, Replacements and Risks*, Feb. 24, 2023. energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

[2] "PJM Chief: Retirements Need to Slow Down," Rich Heidorn Jr., *RTO Insider*, Mar. 27, 2023. PJM Chief: Retirements Need to Slow down | RTO Insider

[3] See, *e.g.*, "Vast Swath of US at Risk of Summer Blackouts, Regulator Warns," By Naureen Malik and David R Baker, *Bloomberg,* May 18, 2022. ("The pace of our grid transformation is out of sync" with the physical realities of the existing power network, [NERC representative] Moura said.)

So the red lights are flashing and there is no excuse not to see them.

What are the chief reasons? I will focus on two.

First, market design in the RTO markets. These markets – which are not really markets at all but administrative constructs with some market characteristics – were designed almost a quarter century ago for a different era with far different challenges than we face today. This is especially true of the capacity markets used in PJM and other eastern RTOs, as well as MISO.

Second, specifically with regard to natural gas, which has been growing rapidly as a source of dispatchable power generation, the national campaign of legal warfare being conducted against every single natural gas pipeline or related facility has prevented the construction of vitally needed natural gas *transportation* infrastructure. Natural gas power generators need a steady and dependable supply of natural gas to generate and deliver power to the grid, and that takes necessary pipeline infrastructure, but the construction of this infrastructure has been all-too-often blocked through legal warfare conducted in all agencies and in all courts.

Since FERC regulates the RTO power markets and has reliability duties under the Federal Power Act, as well as the duty under the Natural Gas Act to permit needed natural gas infrastructure, I believe it is my duty as a member of FERC to call attention to the serious threat to reliability that is looming on the horizon.

Thank you, Mr. Chairman and members of the Committee. I am happy to answer your questions.

Attachment KMM-8

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER23-1609-000

COMMENTS OF THE PUBLIC UTILITIES COMMISSION OF OHIO'S OFFICE OF THE FEDERAL ENERGY ADVOCATE

On April 11, 2023, PJM Interconnection, L.L.C. ("PJM"), pursuant to § 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, filed proposed revisions to its Open Access Transmission Tariff ("Tariff") to revise the Reliability Pricing Model ("RPM") Auction schedule for Delivery Years 2025/2026 through 2028/2029.[1] Specifically, PJM requests an effective date of June 10, 2023, which is four days before the 2025/2026 Base Residual Auction ("BRA") is currently scheduled to open.[2] The Public Utilities Commission of Ohio's ("PUCO") Office of the Federal Energy Advocate ("Ohio FEA") is contemporaneously filing herewith a motion to intervene in this proceeding, thereby becoming a proper party.[3]

For the reasons provided below, the Ohio FEA supports PJM's proposal, and urges the Federal Energy Regulatory Commission ("FERC" or "Commission") to approve it.

I. BACKGROUND

The PJM region is currently undergoing an expansive, multiphase energy transition from predominantly thermal generation resources to lower-carbon resources. This transition is detailed in PJM's recent report, "Energy Transition in PJM: Resource Retirements, Replacements, and

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1 *PJM Interconnection L.L.C.,* "Section 205 Filing to Delay Upcoming RPM Auctions, Request for Waiver to Amend Pre-Auction Activity Deadlines for Impacted Delivery Years, and Request for Expedited Action," Docket No. ER23-1609-000, April 11, 2023 ("PJM Filing").
2 *Id.* at 1-2.
3 Rule 214 of FERC's Rules of Practice and Procedure, 18 C.F.R. § 385.214.

Risks" ("4R Report").[4] Therein, PJM highlights the "potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry,"[5] thus impairing PJM's ability to ensure resource adequacy through 2030.

One of the PJM capacity market's primary purposes is to send "price signals [to] guid[e] resource entry and exit."[6] As such, PJM's proposal indicates that delaying the scheduled BRAs would allow for significant progress in an accelerated stakeholder process known as the Critical Issue Fast Path ("CIFP"), aimed at implementing capacity-market reforms. Such reforms could include enhanced risk modeling, revising market rules to ensure sellers the ability to reflect the risk of capacity commitment, improving capacity accreditation methodologies, and synchronizing capacity-market rules with Fixed Resource Requirements.[7]

II. COMMENTS

A. PJM's Proposal Is Just and Reasonable, Considering the Need for Capacity-Market Reform Before the Next Auction.

On February 24, 2023, PJM published its 4R Report on the energy transition, and the PJM Board announced its decision to initiate the CIFP stakeholder process to make time-sensitive changes to the capacity market, to ensure resource adequacy in light of the risks identified in the 4R Report and elsewhere.[8] PJM intends to file a formal proposal with FERC by October 1, 2023,

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4 Available at https://pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

5 *Id.* at 3.

6 *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,180 (2021), concurring opinion (Commissioner Glick) at 2.

7 PJM Filing at 3.

8 *See Critical Issue Fast Path – Resource Adequacy*, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/cifp-ra; *see also* https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx.

upon completion of the CIFP process, which includes four stages of stakeholder input, voting, then PJM Board review and feedback.[9]

The Ohio FEA asserts that the capacity-market reforms currently underway are critically important for mitigating risk and ensuring near- and long-term resource adequacy and reliability. Indeed, improving the rules by which future auctions are conducted will help ensure just and reasonable rates. While delaying auctions is not an ideal option under most circumstances, the Ohio FEA asserts that the instant proposed delay is relatively brief, and that the time spent improving the capacity-market rules is worthwhile in the long run.

The Ohio FEA supports this delay because having reforms in place before the next auction is the best way, under the current circumstances, to address demonstrated reliability threats, including:

1. As explained in the 4R Report, without reform, there is potential for a timing mismatch, whereby new generation fails to come online soon enough to replace existing generation retirements;

2. The 4R Report highlights that PJM finds that 40 gigawatts (GW) of existing units are expected to retire due to economic and policy drivers, which included 6 GW of announced retirements. In the ten weeks since the publication of the 4R Report, an *additional* 3.3 GW[10] of existing units have announced deactivation;

3. Winter Storm Elliott, in late December of 2022, was the first system-wide Performance Assessment Interval under the current capacity-market rules. This three-day event has resulted in approximately $1.8 billion in non-performance charges on

9 *See* https://www.pjm.com/-/media/committees-groups/cifp-ra/postings/cifp-ra-issue-charge.ashx at 4.

10 PJM, Generator Deactivations, available at https://www.pjm.com/planning/services-requests/gen-deactivations.

resources,[11] with several entities in default or bankruptcy.[12] While these penalties are, under the current structure, intended to deter underperformance, there were approximately 750 capacity resources that underperformed during the storm.[13]

Pursuant to § 205 of the FPA, PJM must establish only that its proposal is "just and reasonable,"[14] and PJM carries its burden. Here, delaying the BRAs to prevent locking in the current circumstances for future delivery years is the only just and reasonable option. The Ohio FEA is optimistic that the benefits of the reform will justify this delay. The process by which CIFP continues to be implemented is robust and provides ample opportunity for all stakeholders to collaborate on finding solutions to these complicated problems. To date, stakeholders are actively engaged in Stage Two of four delineated review stages, which will eventually include a vote of the Members Committee (currently scheduled for August 23, 2023), before allowing time for PJM Board review. Thereafter, the PJM Board intends to share feedback with members, at which time members will presumably be invited to engage in meaningful conversation with the Board before a formal filing is made at FERC by October 1, 2023. The Ohio FEA acknowledges that PJM stakeholders have initiated a process in addition to the CIFP, aimed at establishing *some* reforms before October.[15] However, these efforts do not obviate the need for a holistic reform to be in place before the next auction. The Ohio FEA remains actively engaged in these stakeholder processes to

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11 PJM Winter Storm Elliott FAQ, available at https://www.pjm.com/-/media/markets-ops/winter-storm-elliott/faq-winter-storm-elliott.ashx (as updated on April 12, 2023).

12 PJM Performance Assessment Interval (PAI) Settlements, Risk Management Committee, April 25, 2023, available at https://www.pjm.com/-/media/committees-groups/committees/rmc/2023/20230425/20230425-item-03a-1---pai-settlements.ashx.

13 PJM Winter Storm Elliott FAQ, available at https://www.pjm.com/-/media/markets-ops/winter-storm-elliott/faq-winter-storm-elliott.ashx (as updated on April 12, 2023).

14 *City of Winnfield, La. v. FERC*, 744 F.2d 871, 874–75 (D.C. Cir. 1984).

15 *See* PJM, Markets & Reliability Committee, available at https://www.pjm.com/committees-and-groups/committees/mrc (under Meeting Materials; 4.26.23; document links containing "Capacity Performance Penalty Rate Alignment").

support PJM's anticipated timeline for comprehensive capacity-market reforms before the next auction.

B. Thermal Resources Must Be Valued as Part of Capacity-Market Reform.

The Ohio FEA fully supports the integration of clean energy and inverter-based resources into the PJM footprint's energy grid, but also asserts that an "all of the above" approach is most prudent for ensuring resource adequacy, particularly when considering increased demand expectations as demonstrated by recent load forecasting.[16] Additionally, a review of the current and projected retirement rates for thermal resources – due to economic factors such as non-performance penalties assessed after Winter Storm Elliott, and in response to expanding federal and local environmental and climate regulations – highlights the need to maintain a diverse resource mix throughout the energy transition.

In FERC's Reliability Technical Conference Docket, the North American Electric Reliability Corporation's ("NERC") President and CEO, Jim Robb, recently testified on the value of variable energy resources. "As large baseload generators continue to retire, energy from these plants is being replaced in large measure by variable resources and natural gas units. Natural gas – a dispatchable, flexible resource – plays a critical role as a balancing and energy firming resource supporting widespread deployment of variable resources essential to achieving clean energy goals."[17]

Further, in its most recent Long-Term Reliability Assessment ("LTRA"), issued in December 2022, NERC cautioned:

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16 *See* 4R Report at 14-15.

17 Statement of NERC 2022 Annual Reliability Technical Conference, Docket No. AD22-10-000, November 10, 2022, at 1, available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230117-4001&optimized=false.

> As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid.[18]

Specifically, regarding the PJM region, NERC's LTRA continued:

> PJM's existing installed capacity reflects a fuel mix comprising approximately 43% natural gas, 27% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. *A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.* Totaling over 76,000 MW (nameplate), renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 56% of the generation in PJM's interconnection queue.[19]

The penalties recently assessed from Winter Storm Elliott may further drive economic retirements faster than the grid can handle, highlighting the need to proceed cautiously through the energy transition to preserve resource adequacy.

C. The Instant Proposed BRA Delay Is Warranted.

FERC should approve PJM's instant request for flexibility in the auction scheduling, as necessary to meet near- and long-term resource adequacy objectives. Historically, the Ohio FEA has typically opposed auction delays as unreasonably disruptive to PUCO's electric Standard Service Offer auctions and unfair to default service ratepayers, and also as an impermissible threat to wholesale price signals, which incent market entry and exit by providing certainty of future

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[18] *See* NERC, *Long-Term Reliability Assessment*, December 2, 2022, at 7, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

[19] *Id*. at 63 (emphasis supplied).

revenue streams to facilitate price discovery and supplier contracting.[20] The Ohio FEA additionally notes that future, additional delays might ultimately be considered unjust and unreasonable for similar reasons. To this end, the Ohio FEA must reserve the right to raise concerns regarding certainty in auction scheduling, such as including dates certain in PJM's tariffs.

PJM's instant proposal, however, is factually distinguishable from prior delay proposals that the Ohio FEA has opposed. The instant proposal is uniquely necessary, given the very real potential for a timing mismatch between new resources coming online and existing generation fleet retirement. Conducting an auction in June 2023 under the existing rules will serve only to intensify the difficulty of achieving adequate resource procurement amid the energy transition. The Ohio FEA asserts that conducting an auction in June 2023 may drive further retirements of thermal resources without driving the entry of new resources that can either replace their essential reliability enabling attributes, or do so in a timely manner. PJM urgently needs to address the demonstrated reliability concerns that it has identified.[21]

Indeed, in his recent address to the Electric Power Supply Association on March 21, 2023, PJM's CEO, Manu Asthana, succinctly opined, "I think the math is pretty straightforward … I think we need to add [supply resources] faster … but I also think we need to subtract slower and subtract generation only when the replacement generation is here at scale. I really think that's critical."[22]

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20 *See* FERC Docket Nos. EL16-49-000 and EL18-178-000, PUCO Request for Rehearing, January 21, 2020, at 5, FERC Docket No. AD21-10-000, Written Comments of Commissioner Dan Conway, Public Utilities Commission of Ohio, March 29, 2021, at 2, FERC Docket No. ER21-2582, Joint Protest of the Pennsylvania Public Utility Commission and Public Utilities Commission of Ohio to PJM's Filing Concerning Application of the Minimum Offer Price Rule, August 20, 2021, at 5 and 19-20, FERC Docket No. ER21-2877, Protest of the Public Utilities Commission of Ohio, September 20, 2021, and FERC Docket Nos. EL19-47-000, EL19-63, ER21-2444, and ER21-2877, Answer of the Public Utilities Commission of Ohio, December 9, 2021, at 4-7.

21 PJM Filing at 1-2.

22 *See* https://www.rtoinsider.com/articles/31899-pjm-chief-retirements-need-to-slow-down.

D. There Are Possible Workarounds for Future Delays or if Capacity Prices Are Unknown.

Default service procurements in retail choice states like Ohio can be restructured to mitigate the effect of unknown capacity auction results for future years. Restructuring options include utilizing a proxy rate for capacity (which can be trued-up once the actual capacity cost is known before the start of the delivery year), or simply eliminating the capacity component from the product (thus making suppliers whole when their true capacity obligations are established).

While admittedly counter-productive to the price transparency ideally sought in consumer retail transactions and potentially challenging to implement in a way that would ensure full compensation for competitive suppliers, similar provisions could also be included in bilateral contracts between competitive suppliers and retail customers. Although price discovery for a full-requirements product remains frustrated without a known forward capacity price, capacity pass-through provisions can facilitate contracting for all remaining components of generation service, save for the capacity component. The retail price cited in a contract incorporating such a pass-through provision will still comprise the bulk of the costs associated with providing competitive retail electricity service to retail customers.

To date, Ohio's regulated distribution utilities have neither adopted a proxy rate for capacity, nor excluded the capacity component from their default service procurements, which has necessitated significant modifications to their procurement schedules in response to previous FERC-approved capacity-market delays. If FERC approves PJM's instant proposed delay, PJM's capacity auctions would not be back on Tariff schedule until the 2029/2030 delivery year. In response, the PUCO may explore available options to mitigate the impact on default service procurements in the near future.

III. CONCLUSION

For all the reasons provided above, the Ohio FEA asserts that PJM's proposed delay of its RPM auctions is warranted as just and reasonable pursuant to the Federal Power Act. Accordingly, the Ohio FEA respectfully requests that FERC approve it.

Respectfully submitted,

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On Behalf of the Federal Energy Advocate
The Public Utilities Commission of Ohio

May 2, 2023

CERTIFICATE OF SERVICE

I hereby certify that I have on this date caused a copy of the foregoing document to be served on each person included on the official service list maintained for this proceeding by the Commission's Secretary, by electronic mail or such other means as a party may have requested, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated May 2, 2023 at Columbus, Ohio.

/s/ Thomas G. Lindgren
Thomas G. Lindgren
Assistant Attorney General

Attachment KMM-9

Written Statement of Commissioner Dan Conway, Public Utilities Commission of Ohio

FERC PJM Capacity Market Forum, June 15, 2023

Filed on June 2, 2023, in FERC Docket AD23-7-000

Advance Statement for Panel 3

First, some background. Ohio restructured its retail generation service markets in 2000 to have retail competition: our vertically integrated electric utilities were required to separate from their generation assets; and Ohio has a default standard service option, procured through a competitive wholesale auction and provided by the utilities for customers who don't shop. Our transmission owners were required to become members of and transfer control of their facilities to a FERC-approved RTO, which they did, and that is PJM. Ohio restructured, and joined PJM, based on the expectation that PJM would provide a reliable transmission grid, and the wholesale bulk power markets that PJM oversees would provide adequate supplies of power—at all times. And, we rely upon the competitive model for those bulk power markets to deliver reasonable prices. When I participated in a conference concerning PJM's Minimum Offer Price Rule, hosted by this Commission in 2021, I said that the PJM markets generally had met expectations. Today, however, the landscape is different, and we are facing serious resource-adequacy and reliability threats. I have several comments to make about the challenges we face:

1. First, I think we should start by recognizing and confirming collectively a commitment to the purpose of PJM's RPM (Reliability Pricing Model) capacity market. From its inception to now, that purpose has been to support and assure resource adequacy and reliability in our regional bulk power system at reasonable cost. Resource adequacy, which is a predicate to reliability, is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all hours, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. In order to achieve that goal, PJM must maintain an adequate reserve margin over forecasted peak demand—one that is sufficient to meet an appropriate loss-of-load expectation. So, the RPM capacity market is a competition-based tool for achieving resource adequacy and reliability at reasonable cost. Currently, that means providing a reserve margin that meets a LOLE of one day in 10 years. It is not a tool for achieving policy preferences unrelated to that purpose.

   Moreover, as I discussed at the conference in 2021, while FERC and PJM should try to accommodate policy preferences, including those of individual states, any accommodation of those preferences must not conflict with the capacity market's ability to meet its reliability and resource adequacy, at reasonable cost, purpose.

2. Now, two years later, I am increasingly concerned about whether that capacity market is going to be able to achieve its purpose going forward. We are seeing the rapid retirement of existing thermal baseload dispatchable resources that are rich in both the quantity and range of attributes critical to meeting our resource adequacy and reliability objectives: dispatchability/availability, ramping capability, fuel security/assurance, black-start capability, voltage stabilization, and the ability to deliver long-duration energy at a high level of output. Simultaneously, the interconnection queue is filled with replacement resources, mostly intermittent renewable ones, that are relatively poor in both the quantity and range of such attributes. On top of that, the nameplate ratings for the resources that make their way through development and go into service must be significantly discounted in most cases, in order to depict accurately what their capacity values actually are. On the demand side of things, experts, including PJM, are predicting forecasted demand in the RTO to spike due to electrification of transportation, domestic heating, water heating and cooking, and data centers. PJM's recent evaluation of this combination of trends is unsurprising. Reserve margins are deteriorating, and resource adequacy and reliability are at risk, as explained in PJM's recent February report.[1] ReliabilityFirst and NERC confirm these trends and the risks that they present both for PJM and the nation.[2]

Alongside the rapid subtraction from the generation fleet of existing capacity and reliability attribute-rich resources and the addition of relatively attribute-poor intermittent resources, PJM's most recent Base Residual Auctions have been providing historically low prices for capacity commitments. And what has been the resource adequacy experience for consumers in PJM's region? We had a very close call in late December 2022 during extremely harsh winter conditions. The first data point, low PJM capacity market pricing, is diametrically opposed to both PJM's recent February analysis and NERC's warnings. The second data point, which is the risk that most severely affects consumers if realized, is consistent with PJM's February analysis and NERC's warnings. The conclusion I draw is that something is awry with the capacity market structure; something is out of kilter with the incentives it provides (or, perhaps more precisely, fails to provide) to retain or attract capacity resources that do provide robust resource adequacy and reliability attributes.

3. Ohio depends on the capacity market as a safety net or backstop to assure resource adequacy, and thus reliability, and to do so at just and reasonable rates. But the results of recent capacity market auctions provide visible impacts of price suppression and other negative impacts of policies on resource adequacy. The capacity market design must, in this environment, achieve the goal of adequate compensation and incentives to perform. So how do we realign the market design to achieve these goals?

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[1] PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 24, 2023, https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[2] NERC, Summer 2023 Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf, and ReliabilityFirst, Issue 3, 2022 Q3, pg. 1, https://rfirst.org/about/Newsroom/Newsroom%20Library/Issue%203%20Jul-Sep%202022.pdf.

> We must refocus PJM's capacity market on its basic purpose—resource adequacy and reliability – rather than the promotion of state or federal policy initiatives that undermine that purpose, even if unintentional – even if they are well intentioned. As I have said previously, I think that those policies can still be accommodated as long as, and only to the extent that, they do not detract from achieving that primary purpose. The pending stakeholder process at PJM under the Critical Issue Fast Path is a potential vehicle for the solution.
>
> Accreditation will be a fundamental component to the reform. But it must be done right. We need to first determine what attributes the resource-adequacy solution requires. These include the attributes I mentioned earlier. While I am not a power system engineer, it is clear to me that the capacity market should be designed so that it procures sufficient resources with these attributes, using a competitive model, to meet the resource adequacy objective. We must have enough core generation resources, on call, that have the necessary scope and scale of such attributes that can keep us up and running at all times and, if we do get knocked off of our feet, can stand us back up. Finally, we must keep in mind that in the PJM region, the jurisdictions within that region will be affected by the choices of other jurisdictions. Therefore, resource adequacy and reliability of our bulk power system must be achieved on a regional basis, and each jurisdiction must carry its fair share of the responsibility of procuring the necessary resources that provide essential reliability services.

* * *

I have a couple of additional points, to provide some context to my previous remarks. First, as a general matter of principle, I am generation-resource-technology and policy-preference agnostic, but only if, and to the extent that, the technology can support the resource adequacy and reliability purpose. That is, only if, and to the extent that, the technology offers the types of reliability attributes described above.

Second, Ohio's economy has a substantial manufacturing base, and a significant services component. So, in addition to our millions of residential and small commercial consumers, we serve a significant base of large commercial and industrial consumers. Ohio requires an electric system that can reliably deliver sufficient electric services at all times; a system that can support a healthy and productive economy that enables retention and attraction of businesses that employ our residents. We cannot accept a future in which curtailments and other emergency measures become the normal method for maintaining the stability of the bulk power system.

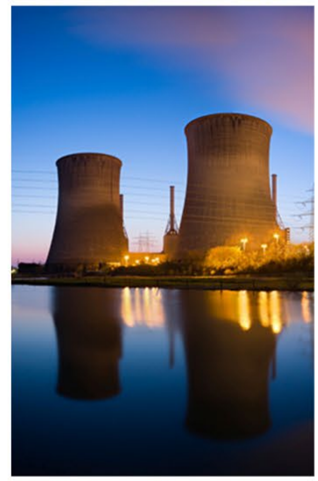
Attachment KMM-10

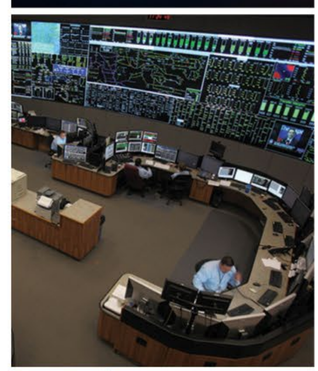
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Announcement

Two-thirds of North America Faces Reliability Challenges in the Event of Widespread Heatwaves





May 17, 2023

ATLANTA – NERC's *2023 Summer Reliability Assessment* warns that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand. While there are no high-risk areas in this year's assessment, the number of areas identified as being at elevated risk has increased. The assessment finds that, while resources are adequate for normal summer peak demand, if summer temperatures spike, seven areas — the U.S. West, SPP and MISO, ERCOT, SERC Central, New England and Ontario — may face supply shortages during higher demand levels.

"Increased, rapid deployment of wind, solar and batteries have made a positive impact," said Mark Olson, NERC's manager of Reliability Assessments. "However, generator retirements continue to increase the risks associated with extreme summer temperatures, which factors into potential supply shortages in the western two-thirds of North America if summer temperatures spike."

This year's assessment, which is summarized in a 2023 Summer Reliability Assessment Video, finds that:

- Areas in the U.S. West are at elevated risk due to wide-area heat events that can drive above-normal demand and strain resources and the transmission network.
- In SPP and MISO, wind energy output will be key to meeting normal summer peak and extreme demand levels due to little excess firm capacity.
- The risk of drought and high temperatures in ERCOT may challenge system resources and may result in emergency procedures, including the need for operator-controlled load shedding during periods of low wind and high generator outages.
- The SERC Central region is forecasting higher peak demand and less supply capacity, creating challenges for operators to maintain reserves in extreme scenarios.
- New England has lower available capacity than last year, resulting in a higher likelihood of system operators using emergency procedures to manage extreme demand conditions.
- In Ontario, extended nuclear refurbishment has reduced available capacity, limiting system reserves needed to manage peak demand.

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In addition to weather-related risks, the assessment identifies a number of reliability issues that should be taken into consideration prior to summer. Owners and operators of grid-connected wind and solar photovoltaic (PV) resources should take steps to ensure these resources can operate reliably during grid disturbances. Additionally, supply chain issues continue to present maintenance and summer preparedness challenges and are delaying some new resources additions. The assessment also makes several recommendations that industry and state policymakers should consider implementing prior to the start of the season:

- Reliability Coordinators, Balancing Authorities, and Transmission Operators in elevated risk areas should review operating plans and protocols for resolving supply shortfalls and:
  - Employ conservative outage coordination procedures.
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand side management mechanisms.
- Generator Owners with solar PV resources should implement recommendations in NERC's *Inverter-Based Resource Performance Issues Alert (Level 2)*.
- Reliability Coordinators, Balancing Authorities and Generator Owners in states affected by the U.S. Environmental Protection Agency's *Good Neighbor Plan* should be familiar with its provisions for ensuring reliability.
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests to preserve generation needed for periods of high demand.

NERC develops its independent assessments to identify potential bulk power system reliability risks. NERC's annual Summer Reliability Assessment provides an evaluation of resource and transmission system adequacy necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the assessment monitors and identifies potential reliability issues of interest and regional topics of concern. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee, the Reliability and Security Technical Committee, the Regional Entities and NERC staff.

The *2023 Summer Reliability Assessment* reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators and regulatory bodies so they are better prepared to take necessary actions to ensure bulk power system reliability.

###

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable and secure North American bulk power system. Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Attachment KMM-11

"The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts"
June 1, 2023

Before the Committee on Energy and Natural Resources
United States Senate
Washington, DC

Testimony of James B. Robb
President and Chief Executive Officer
North American Electric Reliability Corporation

Introduction

The bulk power system (BPS) is at an inflection point. The electric transmission grid is highly reliable and resilient, and has grown more so under the current reliability regime. Yet the risk profile to customers is steadily deteriorating. Factors contribution to this deterioration include:

- Rapid, often disorderly transformation of the generation resource base,
- Performance issues associated with replacement resources as conventional units retire,
- Wide-area, long duration extreme weather events, which are becoming more frequent,
- And increased demand due to electrification, coupled with slow development of new energy infrastructure needed to support grid resilience and the clean energy future.

Independent technical assessments by the North American Electric Reliability Corporation (NERC) find that the energy transformation can be navigated in a reliable way, provided reliability is recognized as a central priority. NERC is concerned that the pace of change is overtaking the reliability needs of the system. Unless reliability and resilience are appropriately prioritized, current trends indicate the potential for more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events.

Outside of cyber/physical security, which presents complex issues worthy of separate discussion, three reliability priorities must be addressed:

- First, we must manage the pace of the transformation in an orderly way, which is currently not happening. Conventional generation is retiring at an unprecedented rate.
- Second, we must identify new resources to replace retiring generation that provides both sufficient energy *and* essential reliability services (such as flexibility, voltage support, frequency response, and dispatchability) needed for stable grid operations.
- Finally, we must shift focus from planning for solely "capacity on peak" to "energy 24x7" due to the changing fuel mix. Further, we need to better understand the impact on the bulk power system from the dynamic performance associated with inverter based resources (IBRs) and distributed energy resources (DERs). These understandings can then

be balanced against the potential for demand side management (both energy efficiency and demand response) to support reliability and resilience.

Within the limits of Section 215 of the Federal Power Act, NERC acts as a reliability regulator for the BPS. NERC has authority over transmission and generation facilities needed to maintain transmission system reliability. However, NERC may not order the enlargement of these facilities, nor may NERC require construction of new transmission or generation capacity. Furthermore, local distribution of electricity and fuel supply are excluded from NERC jurisdiction and fall under State oversight. While the current reliability regime significantly strengthens reliability of North America's transmission system, transformation of the generation resource mix and the expansion of DERs have injected new jurisdictional complexities. Adding to these challenges is the need for industry, regulators, and policymakers to constantly balance reliability with customer affordability and environment impacts, priorities that are outside of NERC's jurisdiction. When viewed through the lens of balancing reliability, economics, and the environment, the challenges for the electricity sector become highly complex.

With a highly reliable, resilient, and secure BPS at the core of NERC's mission, our focus is on proactively addressing the reliability risks of the transforming grid. This testimony examines the growing potential for regional energy shortfalls across North America, NERC's actions to mitigate this risk, and next steps for industry, regulators, Congress, and other policymakers.

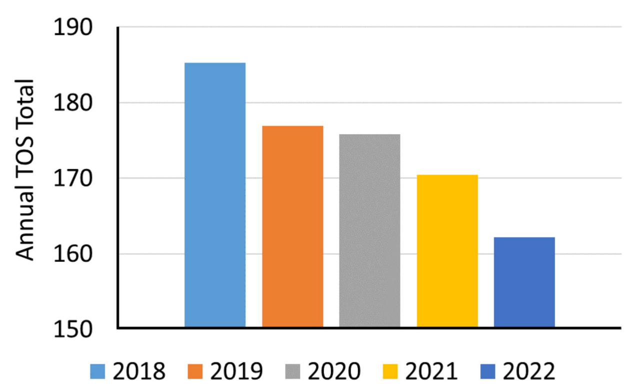
While the Transmission System is Highly Reliable, the Aggregate Electric System is Threatened by a Deteriorating Risk Profile

When the Federal Energy Regulatory Commission (FERC) designated NERC as the Electric Reliability Organization (ERO) in 2006, establishment of a mandatory regime focused on transmission system reliability was the central focus. Through a suite of mandatory enforceable standards, the goal was to align the electricity industry along a common set of essential practices to mitigate reliability risks. Reliability Standards are aimed at avoiding instability, uncontrolled separation, and cascading within an interconnection. While reliability risk mitigation is a complex endeavor, Federal Power Act Section 215 has the distinct advantage of direct jurisdiction tailored to addressing the most pressing risks existing at the time.

The ERO model has been highly successful in reducing risk. By objective measures, today's BPS transmission system is demonstrably more reliable and resilient. Many conventional risks that challenge the grid have now been reduced by significant margins and continue to trend in a positive direction overall. NERC's *2023 State of Reliability Assessment*– to be published later this month – documents a five-year trend of significantly improved transmission system reliability. This includes a system of declining equipment failures, improved human performance, better situational awareness, and effective vegetation management programs. There have been no cyber events impacting bulk electric system facilities, and there have been no outages associated with substations deemed critical to BPS performance and protected under NERC Reliability

Standards. Since 2016, the duration and severity of transmission outages in North America have declined by statistically significant margins.[1] The chart below depicts the decline in transmission outage severity, documented in the upcoming *2023 State of Reliability*. In short, the ERO model is paying significant dividends for the nearly 400 million North Americans who depend upon a reliable bulk power system.

Transmission Outage Severity (TOS)



Source: ***2023 State of Reliability*** *(to be published June 2023)*

However, significant risks have emerged relative to the electricity supply for North America in ways that were not contemplated when the ERO model was established. Mitigation of these new and emerging reliability risks involves a multidimensional set of issues, including a rapidly changing generation resource mix, a changing climate, changing electricity demand profiles, and new technologies, some of which are not quite ready for full deployment. Successful navigation of these issues require multidimensional solutions, often requiring effective coordination of multiple jurisdictions, or examination of new authority where no jurisdiction effectively exists.

If "conventional risk" is defined by risks around which federal jurisdiction provides adequate mitigation, "new risk" is defined by risks to the BPS that cross jurisdictions, are the exclusive province of the states (such as resource and transmission adequacy, and distributed energy resources), or where jurisdiction is unclear or insufficient (such as the interface between the natural gas sector and the electric sector). Solutions to these risks are considerably more complex because, unlike conventional risks, new risks require coordinated engagement among differing jurisdictions or even the establishment of new jurisdictional authorities.

There are three key reliability priorities, outside of cyber/physical security, that will help us address these challenges and be successful. First, we must manage the pace of the transformation in an orderly way, which is currently not happening. Second, we must identify and integrate new resources to replace retiring generation that provides both sufficient energy *and* essential reliability services needed for stable grid operations. Finally, due to the changing

[1] NERC, *2022 State of Reliability: An Assessment of 2021 Bulk Power System Performance (July 2022),* https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

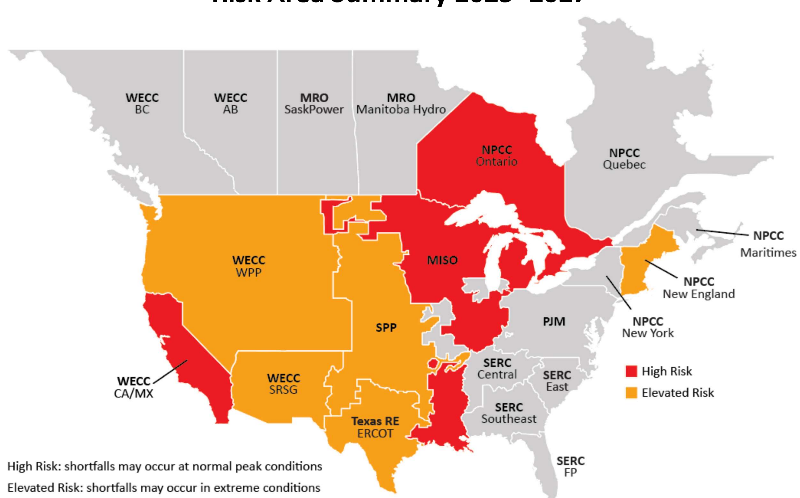
fuel mix, the dynamics associated with DERs, and the potential for demand side management to support reliability, we must shift the planning focus. Whereas resource planning traditionally focused on having enough generation capacity during peak demand conditions ("capacity on peak"), the focus must be broadened to include the need for sufficient energy at all times ("energy 24x7").

NERC Assessments Show Growing Risk of Energy Shortages

NERC's *2021 ERO Reliability Risk Priorities Report*[2] finds that the rapid interconnection of BPS-connected IBRs and how they interact with the high voltage power grid and other resources is the most significant driver of grid transformation and poses a high risk to BPS reliability. The rapidly transforming generation resource mix elevates energy availability as a growing concern for BPS reliability. The dynamic performance of IBRs has not been satisfactory, further elevating the risks for shortfalls when events on the system are experienced. Whether looking out ten years or two months, the risk of energy shortfalls is real and is growing more acute.

NERC's *2022 Long-Term Reliability Assessment*[3] (LTRA) examines future reliability risk over a ten-year horizon. The LTRA finds numerous regions are at risk of energy shortfalls during normal peak conditions and during extreme conditions over the next five years. Factors that contribute to this risk include (1) retirements of flexible, dispatchable resources where their capacity, energy production, and essential reliability services have yet to be fully replaced, (2) extreme weather driven by a changing climate coupled with a generation resource portfolio that has grown more sensitive to extreme weather, and (3) limited addition of interstate electric transmission and fuel delivery infrastructure.

Risk Area Summary 2023–2027



Source: ***2022 Long-Term Reliability Assessment***

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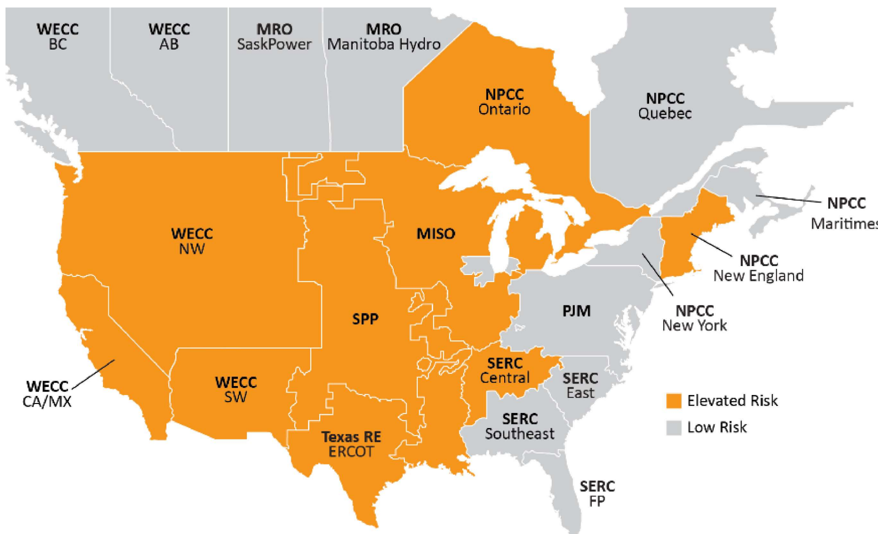
[2] NERC, *2021 ERO Reliability Risk Priorities Report* (July 2021), https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf.

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

The risk outlook for the upcoming summer is also concerning. NERC's *2023 Summer Reliability Assessment*[4] reviews the energy outlook for the upcoming summer season, showing a step change in the risk environment. Among positive findings, the below risk map shows improvement over previous years in that there are no areas at risk of energy shortfalls during *normal summer conditions*. Increased deployments of wind, solar, and batteries positively impact resource adequacy. However, the map shows growing contagion of orange areas compared to previous summer assessments. In these areas, during extreme above-normal heat, long duration conditions, there is a ten percent chance of energy shortfalls occurring.

Summer Reliability Risk Area Summary



Source: ***2023 Summer Reliability Assessment***

NERC Actions to Address Risks

To address the myriad challenges for BPS reliability, NERC has developed a comprehensive risk framework to guide the ERO in the prioritization of risks and provide guidance on the application of ERO policies, procedures, and programs to inform resource allocation and project prioritization. Certain key actions are described below.

Inverter-Based Resource Strategy

The speed of IBR resource deployment continues to challenge grid planners, operators, protection engineers, and many other facets of the electricity sector. Implemented correctly, inverter technology can provide significant benefits for the BPS. However, the new technology can introduce significant risks if not integrated properly. In *2022 State of Reliability*, NERC finds that large assessment areas have become dependent upon renewable resources to meet peak loads, but multiple events resulting in the loss of significant amounts of solar resources in Texas

[4] NERC, *2023 Summer Reliability Assessment* (May 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

and California confirm that unaddressed inverter interconnection and performance issues increased reliability risk.[5] The *2021 Long-Term Reliability Assessment*[6] projects a rapid growth of IBRs – mostly wind, solar photovoltaic (PV), battery energy storage systems, and hybrid plants – with projections of nameplate capacity for solar PV projects in all development stages exceeding 500 GW over the next 10 years. NERC has developed an IBR mitigation strategy comprised of specific activities under four core tenets: Risk analysis, interconnection process improvements, best practices and education, and new standards to govern the planning and operations of IBRs.[7] NERC is also revising its rules to ensure that a greater portion of IBRs are subject to such standards and fall within the nation's regime for a reliable bulk power system.

Energy Assessments

Historically, analyses of energy available to the bulk electric system focused on capacity reserve levels across peak-demand time periods. Energy availability and essential reliability services were assumed to be a direct result of this certain capacity. The variability of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all create uncertainty in the system's ability to provide energy and essential reliability services needed for reliable operation. Recent events, including Winter Storm Uri, have highlighted the need for energy reliability assessments that analyze all hours of a given study period rather than just the peak hours.

After undertaking extensive industry stakeholder engagement, NERC's Energy Reliability Assessment Task Force initiated two Standard Authorization Requests (SARs) which were endorsed by the Reliability Security Technical Committee (RSTC) to mitigate this risk through energy assessments with corrective action plans. Various regulatory jurisdictions then would assess these plans for implementation or modification. The SARs, which are working through the NERC Reliability Standards process, would require Reliability Coordinators and Balancing Authorities to conduct energy assessments needed to evaluate energy requirements in their regions. One SAR would require energy assessments for the long term planning horizon (1 to 5 years), with corrective actions plans toward ensuring sufficient amounts of energy are available for a select set of scenarios.[8] The second SAR is for operational planning (1 year or less), with energy surveys and actions that can be taken to ensure sufficient amount of energy reserves are available to meet energy requirements.[9] Subject to the standards development process, review

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[5] NERC, *2022 State of Reliability* (July 2022), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

[6] NERC, *2021 Long-Term Reliability Assessment* (Dec. 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[7] NERC, *Quick Reference Guide: Inverter-Based Resource Activities and Strategy* (March 2023), https://www.nerc.com/pa/Documents/IBR_Quick%20Reference%20Guide.pdf.

[8] SAR, "Energy Assessments with Energy-Constrained Resources in the Planning Time Horizon," (June 8, 2022), https://www.nerc.com/pa/Stand/Project202203EnergyAssurancewithEnergyConstrainedR/2022-03%20Constrained%20Resources%20in%20the%20Planning%20Time%20Horizon%20Standard%20Authorization%20Request.pdf.

[9] SAR, "Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons," (June 8, 2022), https://www.nerc.com/pa/Stand/Project202203EnergyAssurancewithEnergyConstrainedR/2022-03%20Constrained%20Resources%20in%20the%20Operations%20and%20Operations%20Planning%20Time%20Horizons%20Standard%20Authorization%20Request.pdf.

and approval by the NERC Board and FERC, these new requirements will provide important planning tools to help assure energy availability.

Cold Weather Reliability Standards and Planning

FERC recently approved enhancements to Reliability Standards that address numerous recommendations identified in the FERC/NERC/Regional Entity Joint Inquiry Report that pinpointed lessons learned from the Winter Storm Uri arctic cold front event that affected Texas and the South Central United States in February 2021. The standards also build upon NERC's prior work, further advancing reliability through improved operations, generator cold weather preparedness requirements, and enhanced situation awareness between generators and reliability coordinators and balancing authorities. New and enhanced Reliability Standards address important activities such as cold weather preparedness planning, training requirements, freeze protection measures, and load shedding procedures. A separate joint inquiry is currently ongoing concerning Winter Storm Elliott that affected parts of the Southeast around the Christmas holiday last year. Upon conclusion of the inquiry, NERC intends to act expeditiously on recommendations. Finally, on May 15, 2023, NERC issued a Level 3 "Essential Actions to Industry" Alert urging immediate action and requiring industry to report to NERC on cold weather preparations for next winter.

Expanded Analytics and Modeling

NERC is undertaking a number of initiatives to improve analytics and modeling necessary to support grid transformation in a reliable way. Transmission Planners and Planning Coordinators are concerned about the lack of accurate modeling data and the need to perform more sophisticated studies during the interconnection process and long-term planning horizon. In many ways, the growth of inverter technology has pushed conventional planning tools to their limits, elevating a need for good models required to conduct more detailed studies using electromagnetic transient (EMT) models to address inverter-based resource integration issues. EMT studies have been used since the mid-1970s, and are now needed for studying possible reliability issues related to the interconnection of inverter-based resources. NERC is currently working on Reliability Standards proposing to include EMT models and studies in planning-related NERC Reliability Standards to ensure reliable operation of the BPS.

The NERC Inverter-based Resource Performance Task Force (IRPTF, now the Inverter-based Resource Performance Subcommittee or IRPS) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in the "IRPTF Review of NERC Reliability Standards White Paper."[10] This project includes potential revisions to a number of NERC modeling standards to require, among other things, Generator Owners to provide verified dynamic models to their Transmission Planner for the purposes of power system planning studies. In addition, the IRPTF

[10] NERC IRPTF, "IRPTF Review of NERC Reliability Standards" (Mar. 2022), https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf.

recommended revisions to clarify the applicable requirements for synchronous generators and IBRs.

Findings and Recommendations

Managing the pace of change is the central challenge for reliability. The rapid evolution of the generation resource mix is altering the operational characteristics of the grid. Through the transition:

- Until energy, capacity, and essential reliability services are fully replaced, the retirement of traditional units must be managed. This may require a new pricing construct to ensure that necessary reliability investments (e.g., winterization investments, costs to firm up fuel supply, etc.) are adequately compensated for in the competitive markets.
- It is imperative to understand and plan for the different operating characteristics of variable, inverter-based resources and take steps to ensure they contribute to reliability.
- The reliability attributes of all resources, especially fuel security and provision of essential reliability services, must be recognized and valued by the marketplace.
- Interagency coordination is absolutely needed for policies that impact generation, especially coal resources, to keep reliability at the forefront of the policy table.

More transmission and natural gas infrastructure is required to improve the resilience of the electric grid. Whatever approaches may ultimately be pursued, few long-haul transmission lines and pipelines are actually being planned and built. With construction scheduled to begin this summer, the current major project being developed in the desert Southwest underwent sixteen years of development and permitting. And the New England Clean Energy Connect project has resumed production after being halted through a ballot initiative in Maine. Despite these siting and permitting challenges, it is absolutely clear that:

- Electric transmission investment must keep pace with the increase in utility scale wind and solar resources, which are generally located outside of major load centers. Transmission investments can also strengthen the ability to transport power to different load centers, improving resilience through redundancy. Many are discussing the merits of a national transmission system similar to the interstate highway system, point-to-point DC lines, and other interconnections.
- Additional pipeline infrastructure (including gas storage to provide needed in-market flexibility) is needed to reliably serve load and enable natural gas to perform and even expand its role as a balancing resource.

Natural gas is essential to a reliable transition. Natural gas will remain essential to reliability for total energy and as a balancing resource. In many areas, natural gas-fueled generation is needed to meet energy demand during shoulder periods between times of high and low renewable energy availability, and to set frequency needed by IBRs until advanced grid forming inverters are in placed coupled with energy storage. And on a daily basis in areas with significant solar generation, the natural gas fleet is a flexible generation resource to fill the gap. The criticality of natural gas as the “fuel that keeps the lights on” will remain until very large-scale and long duration battery deployments are feasible or an alternative flexible fuel such as hydrogen, or small nuclear reactors can be developed and deployed at scale.

Regulation and oversight of natural gas supply for electric generation needs to be rethought**.** – While natural gas is key to supporting a reliable transformation of the grid, the natural gas system is not built and regulated to serve the needs of an electric power sector that is increasingly dependent upon reliable natural gas service. As it relates to BPS reliability, clear regulatory authority is needed over natural gas when used for electric generation. As seen in Storm Uri, the interdependence between the electric and natural gas sectors are increasing, and therefore the interface between these two energy subsectors require common practices on how to plan and operate these systems to benefit, not reduce, their reliable operation.

Planning for widespread extreme weather. The BPS must remain reliable and resilient during all operating conditions. As the recent extreme weather events show, industry should proactively plan for and recover from rare but expected events. Through event analysis, reliability assessments and Reliability Standards, and NERC Alerts, NERC is identifying and attempting to address these risks within our jurisdictional authorities. Regulatory and market structures need to support this planning, prioritize reliability, and support necessary investments.

Resource adequacy (capacity) does not guarantee energy sufficiency. We must shift focus to 24x7 energy planning, not just capacity plus a reserve margin. A diverse generation portfolio strengthens reliability and resilience, yet the benefits of diversity are lost when all resources underperform or fail. All generation sources have energy limits and physical constraints, and these limits and constraints need to be accurately accounted for in seasonal and long-term planning assessments.

Energy storage can and will be a game changer. As the technology continues to develop and economics continue to support the growing penetration of energy storage, these resources will become a game changer. However, we have to appreciate the gap that currently exists and the scale that we need to obtain. Investment in energy storage technologies and/or a hydrogen production and delivery systems will be required to achieve a largely or completely decarbonized electric system. Namely, a full system approach is needed to support the clean energy systems of the future.

Market Issues. While electricity market issues are outside of NERC's direct purview, policymakers, planners, and market operators need to understand how electricity market policies value reliability and incentivize investments in hardening energy infrastructure.

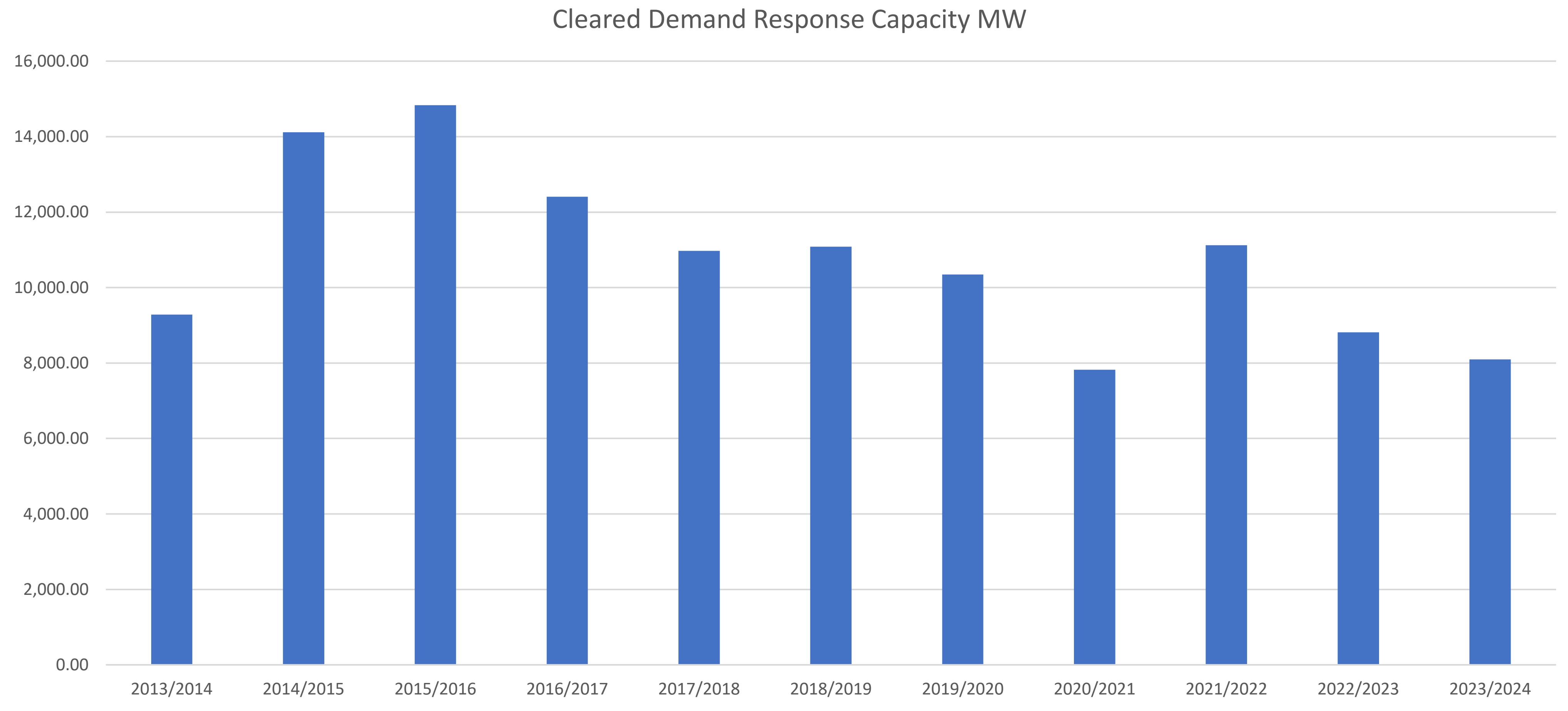
Conclusion

Bulk power system reliability is at an inflection point. NERC assessments demonstrate that the electric grid is operating ever closer to the edge where reliability is at risk – an edge characterized by the prospect of more frequent and more serious disruptions that threaten human wellbeing and economic productivity. To be clear, NERC believes that the energy transformation can be navigated in a reliable way. To do so, reliability must be anchored as our north star guiding the journey, with flexibility for course corrections that are surely needed for such a highly complex endeavor. The challenge is not whether we have the resources and technical ability to achieve a clean energy future. Rather, the central challenge is calibrating the pace of change with the reliability needs of a transforming system that must remain reliable and resilient at all times and under all conditions. As it exists today, this balance is out of calibration and must be corrected.

As the Electric Reliability Organization for the United States, NERC is exercising its full range of tools to support a highly reliable and secure North American bulk power system. The transmission system is indeed highly reliable, yet the aggregate electric system is threatened by a deteriorating risk profile. NERC's technical work is key to identifying risks and informing reliability actions identified in this testimony. NERC actively communicates risks to industry stakeholders, regulators, and policymakers, and develops additional regulatory measures to help address risks. With reliability as the central focus, solutions are found in coordination among jurisdictions, industry collaboration, and exploration of new authorities where needed. NERC is fully engaged in these endeavors and remains deeply committed to our work with this committee, industry stakeholders, and all policymakers to navigate this journey together.

Attachment KMM-12

PJM Historical Demand Response



Attachment KMM-13

STANDARD CONTRACT RIDER NO. 17
CURTAILMENT ENERGY
(Applicable to Rates CSC, HL, PL, SL, & PH)

AVAILABILITY:
Available to the Rate HL, PL, SL, and PH Customer who enters into a written contract to curtail a portion of Customer's electric load upon request. The Company will, from time to time, inform interested Customers of the terms for Curtailment Energy. This rider is not available to any Customer who is otherwise interruptible or curtailable. Company does not warrant uninterrupted delivery of energy and a Customer choosing this Rider remains subject to periods of reduced energy supply due to disruptions of transmission or distribution facilities or any failure of supply regardless of cause.

DEFINITIONS:

Contract Term:	Calendar months that the Company offers to purchase Curtailment Energy (generally, but not exclusively, quarterly).
Firm Power Level (FPL):	The demand in KW that Customer agrees not to exceed during each Curtailment Period.
Curtailment Period:	A period of time chosen by the Company in its sole discretion during which the Customer, after proper notification, should reduce its metered KW load to the FPL. The Curtailment Period does not include any period of reduced electric supply applicable due to disruption to transmission or distribution facilities, failure of supply or caused by Force Majeure as defined in the contract
Energy Credit Rate:	The energy credit the Customer receives for each KWH of Curtailment Energy Customer provides the Company. The energy credit will be specified by the Company at the time a Contract Term is defined.
Capacity Credit Rate:	The capacity credit the Customer receives for each KW of Curtailment capacity the Customer provides the Company.
Noncompliance Energy Rate:	The charge for each KWH of Noncompliance Energy that the Customer consumes during a Curtailment Period. The charge will be equal to twice the Energy Credit.
Proforma Load:	The Company's estimate of the Customer's load during a Curtailment Period that would have occurred but for the Company's request to curtail.
Available Curtailment Energy:	The KWH energy obtained by subtracting the FPL from the Proforma Load for each hour of the Curtailment Period.

STANDARD CONTRACT RIDER NO. 17 (Continued)

DEFINITIONS: (Continued)

Curtailment Energy:	The KWH energy obtained by subtracting the Customer's actual metered consumption from the Proforma Load for each hour of the Curtailment Period.
Noncompliance Energy:	The result of subtracting Curtailment Energy from Available Curtailment Energy. Negative values will not be used in billing.
Curtailment Capacity:	The difference between the Customer's billing demand and the FPL.

ADJUSTMENTS TO MONTHLY BILLING:
Curtailment Energy will be added to the Customer's metered energy during each Curtailment Period. The Company can specify a recovery period following a Curtailment Period. During the recovery period, the Customer's demand will not be used in determining the billing demand; however, the Customer must still limit his consumption to the capacity of the existing service. The availability and timing of a recovery period will be set for each Contract Term. All credits and charges will be calculated for a calendar month and reflected on a subsequent bill issued to the Customer.

NOTIFICATION OF CURTAILMENTS:
The Company will provide at least 10 hours' notice prior to the beginning of a Curtailment Period. Notification procedures will be specified in the contract.

MAXIMUM HOURS CUSTOMER REQUESTED TO CURTAIL LOAD:
The Company in its sole discretion will set the maximum hours for curtailment at the time a contract offer is made. The hours will be limited for the Contract Term and for each month of the Contract Term. The Curtailment Period will not be more than 8 hours in any one day, and does not include any period of reduced electric supply applicable due to disruption to transmission or distribution facilities, failure of supply or caused by Force Majeure as defined in the contract.

MINIMUM CURTAILMENT CAPACITY:
Customer will provide at least 500 kW Curtailment Capacity. School systems with multiple services can have services with less than 500 kW of Curtailment Capacity, but the total Curtailment Capacity of all services must be greater than 2000 kW and there will be one notification per school system.

CALCULATION OF MONTHLY ENERGY CREDIT:
Customers will receive a credit that is the product of the Energy Credit Rate and the Curtailment Energy.

CALCULATION OF MONTHLY CAPACITY CREDITS:
Customers will receive a credit that is the product of the Curtailment Capacity and the Capacity Credit Rate. The credit will be reduced by an administrative fee, which will be set for each Contract Term.

CALCULATION OF MONTHLY NONCOMPLIANCE ENERGY CHARGE:
Customers will receive an additional charge that is the product of the Noncompliance Energy Rate and Noncompliance Energy or applicable MISO penalty, whichever is greater.

STANDARD CONTRACT RIDER NO. 17 (Continued)

NONCOMPLIANCE:
If in any month the Curtailment Energy as a percent of the available Curtailment Energy is less than 95%, the Customer may, at the Company's discretion, lose the Capacity Credit for that month. If in any month the Curtailment Energy as a percent of the available Curtailment Energy is less than 90%, the Customer may, at the Company's discretion, lose the Capacity Credit for that month and pay the Company an amount equal to the lost Capacity Credit. Continued non-compliance may also result in the Customer's removal from the program at the Company's discretion.

Attachment KMM-14

Curtailable Service Rider-1

APPLICABLE

In all territory served.

AVAILABILITY

Availability limited to Customers served under applicable rate schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with Customers already participating in this rider, on or after July 1, 2017. T/D/N N N

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed 375 hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. Customer's choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

> Option A -- Customer may contract for a given amount of firm demand in kVA. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance. T T T T T

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Option B -- Customer may contract for a given amount of curtailable load in kVA by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand in kVA immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}.

Non-compliance for each requested physical curtailment shall be the measured positive value in kVA determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service:	$ 3.56 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$ 3.67 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. The Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow the Company to control Customers' curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) Customer's measured maximum demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M., (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be Customer Designated Curtailable Load, as described above.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP is the Cash Price for "Natural Gas, Henry Hub" for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

CERTIFICATION

Upon commencement of service hereunder, Customer shall be required to demonstrate or certify to Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by Customer, Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by Company, Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

DATE OF ISSUE: July 20, 2021

DATE EFFECTIVE: With Service Rendered
On and After May 1, 2019

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00295 dated April 30, 2019

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

APPLICABLE

In all territory served.

AVAILABILITY

Availability limited to Customers served under applicable rate schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with Customers already participating in this rider, on or after July 1, 2017. T T/D/N N N

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed 375 hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time. Company may request or cancel a curtailment at any time during any hour of the year.

Company may request at its sole discretion physical curtailment no more than twenty (20) times per calendar year totaling no more than 100 hours. Company will request physical curtailment only when more than ten (10) of the Companies' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Companies are making off-system sales. However, to avoid a physical curtailment a CSR Customer may buy through a requested curtailment at the Automatic Buy-Through Price. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours under the buy-through option discussed below. If all available units have been dispatched or are being dispatched, Company may request physical curtailment without a buy-through option. After receiving a physical curtailment request from Company where a buy-through option is available, a CSR Customer will have 10 minutes to inform Company whether the Customer elects to buy through or physically curtail. If the customer elects to physically curtail, the Customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time Company requests curtailment to the time the Customer must implement the curtailment). If a Customer does not respond within 10 minutes of notice of a curtailment request from Company, the Customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the Customer. After receiving a physical curtailment request from Company when no buy-through option is available, a CSR Customer will have 40 minutes to carry out the required physical curtailment.

Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements. Customers choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. For such curtailments, Company will give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand in kVA. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual kWh – (firm kVA x hours curtailed)]. The measured kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

Option B -- Customer may contract for a given amount of curtailable load in kVA by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand in kVA immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}.

Non-compliance for each requested physical curtailment shall be the measured positive value in kVA determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) Customer's maximum demand during such curtailment.

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RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service:	$ 5.90 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$ 6.00 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

Failure of Customer to curtail when requested to do so may result in termination of service under this rider. Customer will be charged for the portion of each requested curtailment not met at the applicable standard charges. Company and Customer may arrange to have installed, at Customer's expense, the necessary telecommunication and control equipment to allow Company to control Customer's curtailable load. Non-compliance charges will be waived if failure to curtail is a result of failure of Company's equipment; however, non-compliance charges will not be waived if failure to curtail is a result of Customer's equipment. If arrangements are made to have telecommunication and control equipment installed, then backup arrangements must also be established in the event either Company's or Customer's equipment fails.

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) Customer's measured maximum demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., (EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M., (EST) and (b) the firm contract demand.

For a Customer electing Option B, Curtailable Billing Demand shall be the Customer Designated Curtailable Load, as described above.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP is the Cash Price for "Natural Gas, Henry Hub" for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

CERTIFICATION

Upon commencement of service hereunder, Customer shall be required to demonstrate or certify to Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be two (2) years and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When Company requests curtailment, upon request by Customer, Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by Company, Customer shall provide to Company a good-faith, non-binding short-term operational schedule for their facility.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

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CERTIFICATE OF SERVICE

In accordance with Rule 4901-1-05, Ohio Administrative Code, the PUCO's e-filing system will electronically serve notice of the filing of this document upon the following parties. In addition, I hereby certify that a service copy of the foregoing *Direct Testimony of Kevin M. Murray on Behalf of The Ohio Energy Group* was sent by, or on behalf of, the undersigned counsel for The Ohio Energy Group to the following parties of record this 9th day of June, 2023, *via* electronic transmission.

/s/ Michael L. Kurtz
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