2023 RTO Membership Analysis

Section 1: Overview and Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") are required by the Kentucky Public Service Commission ("KPSC" or "Commission") to annually file a report evaluating whether joining a regional transmission organization ("RTO") would be in the best interest of customers.[1] This 2023 RTO Membership Analysis builds on work performed in the previous five RTO reports and extensive information related to RTOs that was filed as part of the Companies' recent application for various Certificates of Public Convenience and Necessity ("CPCNs").[2] The primary conclusions of this year's analysis are:

1. The most recent quantitative and qualitative information regarding RTO membership, including the thorough discussion of such membership that occurred during the currently pending CPCN case, does not currently support initiating detailed discussions with MISO or PJM regarding membership;
2. Due to uncertainty regarding reliability concerns and related capacity market reforms in MISO and PJM, as well as the timing of this report relative to the issuance of a final order in the currently pending CPCN case, performing additional quantitative analysis at this time would be unproductive at this time;
3. Until either MISO or PJM demonstrates that it has clearly and sustainably addressed market design and related capacity adequacy and reliability issues, it will be extremely challenging for the Companies to fully assess the potential net costs or benefits of joining either RTO; and
4. Nonetheless, as part of their 2024 Integrated Resource Plan ("IRP") process, the Companies plan to perform a multi-faceted analysis of both PJM and MISO membership that will address the final outcome of the currently pending CPCN case, any guidance or requirements the Commission includes in its final order in the CPCN case, and other relevant developments, including the implications of alternative market designs, pending EPA regulations (e.g., 111(b) and 111(d)), and alternative capacity accreditation regimes.

For the reasons stated above, this report focuses on the reliability and market issues that are ongoing in both MISO and PJM and the challenges each RTO faces in addressing its future capacity and energy needs. How MISO and PJM ultimately address these issues will be important to the multi-faceted RTO study the Companies will file with their 2024 IRP.

Finally, the Companies remain open to the possibility of future RTO membership, and they believe that continuing to study it, albeit perhaps at less frequent intervals such as in conjunction with IRP and CPCN proceedings, is entirely appropriate. But because exiting an RTO is much more challenging and costlier

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[1] *See Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).
[2] *See Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2022-00402.

than entering one, prudence requires that the benefits be clear and durable before making such a commitment.

<u>Section 2: Recent Quantitative Analyses Suggest RTO Membership Remains Unfavorable; Additional Quantitative Analysis Would Require Clarity on Several Issues to Be Useful</u>

The Companies' 2022 RTO Membership Analysis demonstrated that PJM membership would be disadvantageous to customers in all four of the fuel and CO_2 price scenarios evaluated by at least $270 million NPVRR.[3] In the Companies' recent CPCN case, the Companies provided a corrected version of their analysis that showed PJM membership would be disadvantageous to customers by at least $421 million NPVRR and by as much as $1.2 billion NPVRR:[4]

Figure 1 - Net Benefits/(Costs) of Joining PJM (Nominal $M)

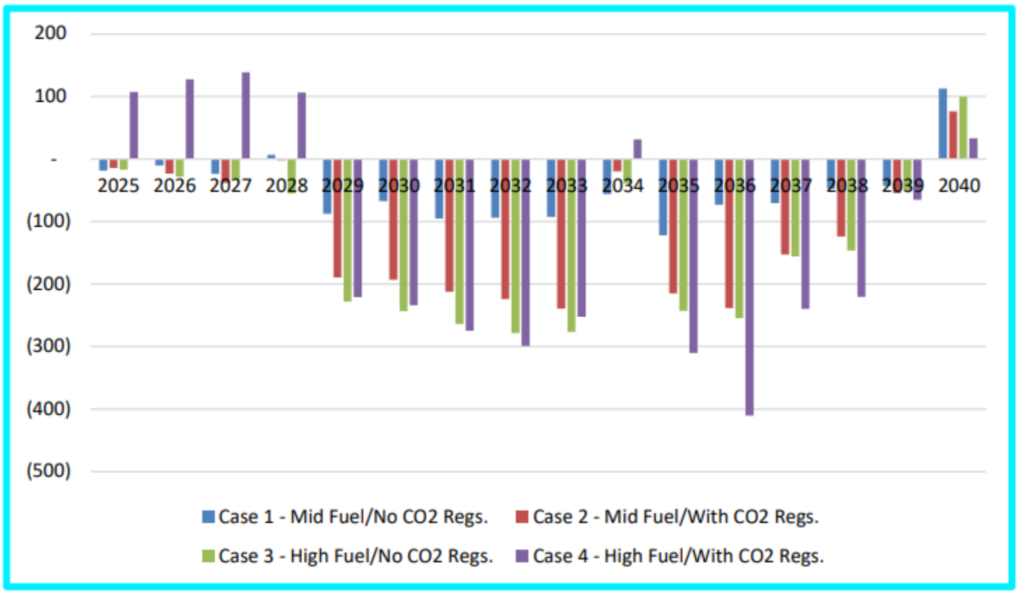

Table 2 - Net Benefits/(Costs) of Joining PJM ($M)

	Case 1	Case 2	Case 3	Case 4
Nominal	(783)	(1,864)	(2,212)	(1,983)
2022 PV Dollars	(421)	(966)	(1,166)	(848)

[3] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, 2022 RTO Membership Analysis (Nov. 14, 2022); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, 2022 RTO Membership Analysis (Nov. 14, 2022).

[4] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2022-00402, Companies' Response to Sierra Club's Second Request for Information No. 26(b), Corrected RTO Membership Analysis at 5-6 (May 4, 2023).

The costs and benefits of PJM membership were the subject of extensive discovery and testimony in the currently pending CPCN case, the evidentiary record of which closed last month. Notably, although certain parties to the CPCN case asserted that PJM membership would be economical for the Companies, no intervenor conducted a complete cost-benefit analysis, and the limited analysis provided by a Sierra Club witness omitted such items as annual PJM membership costs and assumed the Companies would retire coal-fired units with *no* replacement capacity,[5] which would require the Companies to serve customers via market purchases year-round and around the clock.[6] The Companies are unaware of any input cost or other data from the ten-month CPCN case that would clearly or decisively change the quantitative analysis presented in the 2022 RTO Membership Analysis. Thus, it is reasonable to conclude based on recent and extensive quantitative analysis and review that RTO membership remains unfavorable for the Companies' customers at this time.

The 2022 RTO Membership Analysis and the evidence in the recent CPCN case show that retiring the coal-fired units the Companies propose to retire by 2028 will require new replacement capacity, particularly NGCC capacity, to avoid relying on market purchases indefinitely to reliably and economically serve customers.[7] Moreover, as discussed in the CPCN case and below in this report, RTOs have recently made clear pronouncements that rapid-ramping dispatchable thermal resources like NGCC units will be needed for the foreseeable future to ensure reliability, making the addition of such units to the Companies' portfolio advantageous to possible future RTO membership.[8]

Finally, certain pieces of information that simply are not available at this time would be required for any additional quantitative analysis to be useful. First and foremost, as discussed at greater length below, both PJM and MISO have recognized the need for capacity market reforms to incentivize the addition of reliable generation that their footprints will require as existing thermal resources continue to retire while load is projected to increase and their interconnection queues are dominated by renewable resources. As Walmart observed in the recent CPCN case, "[M]arkets are in a state of flux due to interconnection issues and the changing energy mix, which RTOs/ISOs are responding to with various market reforms. It is understandable that the Companies would want greater clarity on these issues prior to assessing the 'value' of RTO/ISO membership." Second, the final outcome of the CPCN case will necessarily affect key inputs and assumptions to RTO membership analyses, including the makeup of the Companies' generation portfolio for years to come, but that outcome will not be known until after the filing date of this report. Third and finally, the Companies anticipate that the Commission's final order in

[5] *See, e.g.,* Case No. 2022-00402, Direct Testimony of Michael Goggin at 4-6, 47; Case No. 2022-00402, KIUC Reply Brief at 4-5.
[6] Case No. 2022-00402, Rebuttal Testimony of David S. Sinclair, Rebuttal Exhibit DSS-2 at 8-10.
[7] *See, e.g., id.*
[8] *See, e.g.,* Case No. 2022-00402, Companies' Hearing Exhibit 1, Joint Comments of ERCOT, MISO, PJM, and SPP to the EPA dated Aug. 8, 2023 at 12 (subject to Companies' Motion to Take Administrative Notice dated Sept. 1, 2023) ("[T]here may also be a need to build dispatchable resources such as new natural gas combustion turbines in the coming years to ensure that grid reliability is not jeopardized …."); Case No. 2022-00402, Rebuttal Testimony of David S. Sinclair at 3 (quoting PJM Vice President for State and Member Services Asim Haque stating, "We are going to need thermal resources in order to preserve reliability until replacement tech exists to deploy at scale"); Case No. 2022-00402, Companies' Hearing Exhibit 1, Joint Comments of ERCOT, MISO, PJM, and SPP to the EPA dated Aug. 8, 2023 at 11 ("[I]t is crucial for reliability purposes to maintain certain levels of resources with attributes such as quick start-up and ramping capabilities ….").

the CPCN case will include additional direction regarding future RTO membership analyses, which the Companies look forward to addressing in future reports but necessarily could not address in this report.

<u>Section 3: RTO Developments since the 2022 RTO Membership Analysis</u>

The twelve months since the 2022 RTO Membership Analysis was filed have been a challenging time for both MISO and PJM. Some major events and activities include:

- Winter Storm Elliott and the challenges faced by generators (PJM in particular) to be available when called on to serve load. This event alone resulted in:
    - Along with the events of Winter Storm Uri, the issuance of the NAESB Gas Electric Harmonization Forum Report[9]
    - PJM initially assessed approximately $1.8 billion in generator nonperformance penalties[10]
        - PJM later offered to reduce total penalties by 31.7% to resolve the bulk of outstanding FERC complaints[11]
    - PJM initiated a Critical Issue Fast Path-Resource Adequacy ("CIFP-RA") process to get stakeholder input on how best to preserve reliability into the future[12]
    - The CIFP-RA process did not produce a consensus on potential tariff/market design changes so the PJM Board initiated its own set of changes and filed these with FERC (the filed changes are discussed in Section 4)[13]
    - FERC-NERC-Regional Entity Joint Inquiry Into Winter Storm Elliott[14]
    - PJM Event Analysis and Recommendation Report[15]
    - MISO Winter Storm Elliott Report[16]
- PJM issued a report in February 2023 titled "Energy Transition in PJM: Resource Retirements, Replacements & Risks" that discussed in detail its concerns that thermal units are retiring at a faster pace than new generation (of any type) is being constructed and that the overwhelming volume of new generation being proposed is intermittent, particularly solar (this report is discussed in more detail in Section 4).
- MISO implemented a seasonal capacity construct.

[9] https://www.naesb.org/pdf4/geh_final_report_072823.pdf
[10] https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx
[11] https://www.pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx
[12] https://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
[13] https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx, page 21
[14] https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott
[15] https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx
[16] https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf

- NERC's 2022 Long Term Reliability Assessment identified declining reserve margins in MISO through 2032[17]

__Section 4: Markets in Transition: Resource Adequacy Concerns in PJM and MISO as They Modify Market Rules to Accommodate Increasing Load and Adapt to a Changing Resource Mix__

Growing concerns regarding resource adequacy in PJM and MISO are receiving increasing attention by the RTOs themselves, industry observers, and regulators. On August 3, 2023 PJM Vice President for State and Member Services Asim Haque spoke to the Kentucky General Assembly's Interim Joint Committee on Natural Resources and Energy stating:

- "We are concerned about being in a supply crunch by the end of this decade."[18]
- "We will need thermal resources until those resources can be replaced at scale. And we don't see that technology being integrated into the system, certainly not tomorrow. And so we will continue to need our thermal resources."[19]
- "We are going to need thermal resources in order to preserve reliability until replacement tech exists to deploy at scale."[20]
- "Our queue consists of primarily, again, solar, wind and battery resources. … But, you know, a variable that we're not sure about right now is how much actual renewable generation is going to leave our queue and construct. … [W]e talked about our concern about 40 gigs [GW] retiring by the end of this decade and currently we have 48 gigs [GW] that have found their way through all things PJM and are waiting to construct, but we are not seeing steel in the ground. … [A] variable that we just don't know enough about yet is how much of this generation that is in the queue and finds their way through the queue, how much of this generation is actually going to get built? And we don't have that answer right now. Last year, it's a pretty pitiful two gigs. And 1,300 of it was a natural gas plant in Ohio. 700 of it was renewable."[21]
- "There are a lot of watts in the queue that are some combination of solar, wind, battery resource, and we hope they get built because we need the watts. But as we sit here today, they're not getting built."[22]

Mr. Haque's slides are attached as Appendix 1. Mr. Haque's presentation builds on a report that PJM published in February 2023 titled "Energy Transition in PJM: Resource Retirements, Replacements & Risks."[23] In that report, PJM highlighted that 40 GW of existing generation is at risk of retiring by 2030 – representing 21 percent of its installed fleet.[24] Furthermore, PJM is forecasting load growth of 1.4

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[17] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf pages 25-28

[18] Interim Joint Committee on Natural Resources and Energy Hearing August 3, 2023, YouTube video at 13:25-13:33, available at https://www.youtube.com/watch?v=Bja3IDPFPMs (accessed August 4, 2023).

[19] *Id.* at 1:12:10-1:12:36.

[20] *Id.* at 1:26:53-1:27:00.

[21] *Id.* at 1:19:57-1:22:14.

[22] *Id.* at 1:36:35-1:36:51.

[23] See Appendix 2 for complete report.

[24] Energy Transition in PJM: Resource Retirements, Replacements & Risks, page 2.

percent annually over the next 10 years due to electrification and the addition of data centers.[25] The net result of the various changes in supply and demand are that:

> "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."[26]

Another factor cited in the PJM report that appears to be leading to increasing retirement risk for existing thermal resources is the lack of market revenue to cover their ongoing stay open costs.[27] The dependence on market revenue for a large share of PJM generation is highlighted in an August 2023 report by the Institute for Energy Economics and Financial Analysis ("IEEFA") titled "Private Equity in PJM: Growing Financial Risks."[28] The key conclusions of their analysis are:

- The relatively stable and high capacity payments from the system operator that have enabled the buildout of so much privately owned fossil-fuel generation capacity in PJM have disappeared in the last three years;
- Low capacity auction payments, coupled with the recent sharp runup in interest rates, have worsened the economic outlook for new PJM projects and made merchant projects more economically risky;
- The fines from Winter Storm Elliott have pushed some existing plants into bankruptcy while forcing others to seek capital infusions from their private equity sponsors; and
- The 2010s saw a massive buildout of new capacity with relatively low risk, but the situation today is reversed, and it is a new, much riskier situation for private equity and private capital in the PJM market.[29]

One of the reasons for PJM and IEEFA concerns about market revenues not supporting existing plant operations is that, as the IEEFA report states, there has been a large shift in generation ownership since 2017 from regulated publicly traded utilities to private firms and private equity. The IEEFA report states that in 2017 the five largest capacity owners in PJM were regulated publicly traded utilites, whereas today three of the largest capacity owners are private. Overall, private companies and private equity firms now own approximately 60 percent of fossil-fueled generation capacity in PJM.[30]

In an attempt to address their growing capacity concerns as well as capacity performance concerns stemming from Winter Storm Elliott, on October 13, 2023, PJM filed at FERC some proposed capacity

[25] Ibid, page 2.
[26] Ibid, page 3.
[27] Ibid, pages 9-10.
[28] See complete report in Appendix 3.
[29] Ibid, page 3.
[30] Ibid, page 4.

market changes to be implemented beginning the 2025/2026 Delivery Year.[31] According to its filings, PJM proposes, among other things to:

- Maintain an annual capacity market for now pending more study and input from stakeholders concerning seasonal capacity markets, which the Companies anticipate PJM will eventually need to implement (as MISO has);
- Implement expected unserved energy ("EUE") as an RTO reliability metric;[32]
- Maintain status quo assumptions regarding the ability to import energy from neighboring regions during peak times but recognize a growing concern about resource adequacy in those regions and the need to revisit this issue annually;
- Update the generation capacity performance construct to reduce the stop-loss amount on penalties;
- Reform Performance Assessment Interval ("PAI"), including new PAI Obligation Transfers to hedge market risk;
- Implement generator seasonal capability testing reforms and new operational testing requirements;
- Seek to implement a Marginal Effective Load Carrying Capability ("ELCC") as the accreditation method for all resources;
- Address the risk of correlated outages by incorporating historical unit performance data and expanding the weather history to 30 years;
- Make changes to the Fixed Resource Requirement ("FRR") alternative to make capacity accreditation, testing, and non-performance charge rules the same as entities that participate in the Reliability Pricing Model ("RPM").

In May 2023, MISO conducted their first seasonal capacity auction which implemented a new availability-based capacity accreditation methodology to all resources, following FERC approval in August 2022. Though the auction results projected adequate capacity for Planning Year ("PY") 2023/2024, MISO called for urgent market design reforms to ensure continued reliability saying:

- "Actions taken by Market Participants such as delaying retirements and making additional existing capacity available to the region, resulted in adequate capacity" and that "many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition".[33]

At the heart of MISO's concern was the continuing trend of declining accredited capacity while installed capacity increases.[34] Additional resource adequacy modelling supported this position.

In July 2023, MISO and the Organization of MISO States conducted the 10th annual resource adequacy survey to assess available resource capacity over the next five years. Incorporating the new seasonal capacity construct, they identified a capacity shortfall of 2.1 GW starting the summer of 2025/2026 and

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[31] FERC Docket No. ER24-98-000 (https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-98-000.ashx) and ER24-99-000 (https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx)
[32] https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx
[33] https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf
[34] https://d1dth6e84htgma.cloudfront.net/09_28_23_ENG_Testimony_Ramey_9a96ce2034.pdf

growing each of the next three planning years. John Bear, MISO's chief executive officer responded by saying:

- "These results continue to illustrate the reliability risk we face and reinforce the need for dispatchable, long-duration resources to be maintained and brought online to manage the transition to weather-dependent, low-carbon resources."[35]

To address the resource adequacy risks posed by the continuing trend of dispatchable generation retirement and growing intermittent generation, MISO recently proposed a capacity accreditation enhancement, targeting a FERC filing by the end of 2023. The enhancement would effectively implement a shift to marginal capacity accreditation using individual unit and class average performance during the riskiest hours. However, due to staunch stakeholder opposition to the proposal, MISO announced on October 4 that they will push back a FERC filing for accreditation reform to the first quarter of 2024.[36]

MISO's and PJM's efforts to change their market designs, rules, and tariffs to address the energy issues of today and the coming decades could be challenged by the very assumptions that have underpinned RTOs since their inception over 20 years ago. Some, such as former FERC commissioner Tony Clark and former Senior VP with PJM Vincent Duane in their paper "Stretched to the Breaking Point: RTOs and the Clean Energy Transition" ask the question, "what happens when price is no longer an effective tool for fulfilling the tasks that RTOs were created to complete? If an increasing portion of the grid is characterized by socialized fixed charges and generation that neither sets prices nor responds to price signals, the impact will be profound."[37] In analyzing the issue and attempting to answer this question, they conclude that:

> The engine driving RTO markets is the single-clearing locational marginal price. For the reasons discussed here, we harbor reservation about how this model – one which rests on assumptions of fungibility, non-discrimination and resource neutrality – can continue to work both operationally and economically as more wind and solar interconnect, particularly under the terms stated in Item 1 above [i.e., "[s]upporting renewable entry through programs, tax credits, and out-of-market contracts that value renewable's positive environmental externalities, while affording renewables preferred access to the grid"].
>
> Does this mean that RTOs can't serve as a vehicle to advance decarbonization? No. But we are inclined to think RTO wholesale markets, which are a defining feature, will have to be re-thought from the ground up. This isn't going to come easily or quickly – particularly

[35] https://www.misoenergy.org/about/media-center/oms-miso-survey-results-2024-2025/

[36] https://cdn.misoenergy.org/20231004%20RASC%20Item%2005ai%20Resource%20Accreditation%20Presentation630408.pdf

[37] Clark, Tony and Vincent Duane, *Stretched to the Breaking Point – RTOs and the Clean Energy Transition* at 1 (July 2021), available at https://wbklaw.wpenginepowered.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf (accessed Oct. 11, 2023). Note that the paper is also provided in Appendix 4.

considering structural features of the RTO which we intend to explore in a subsequent paper.[38]

The issue of the operation of RTO price mechanisms was also recently (May 2023) addressed by current FERC commissioner Mark Christie in a paper in the Energy Law Journal titled, "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets."[39] Commissioner Christie made several arguments supporting the need for changes to RTO pricing mechanisms:

- The U.S. should join the UK and EU in a comprehensive reconsideration of RTO pricing mechanisms and ask whether or not the existing mechanisms are capable or the best to deliver cost savings and reliability to consumers, especially given the heavily subsidized deployment of wind and solar generation;
- The immediate focus needs to be on capacity markets because of their reliability impact. "Indeed, it is past time to reconsider whether such constructs, certainly those in the large, multi-state RTOs, are still capable of performing the important duties expected of them."[40]
- The reconsideration of single clearing price mechanisms, despite their prevalence in RTOs, should be done with an open mind, especially with the growth of zero/negative marginal cost wind and solar generation;
- Serious reconsideration of power market mechanisms must include an examination and understanding of the historical context in which they were developed, particularly the "deregulation" movement of the late 1990s and early 2000s. "Reconsidering these pricing mechanisms thus requires a candid reassessment of the assumptions that drove deregulation and whether these assumptions still apply to present reality."[41] "These 'markets,' however – despite the label – have never been true markets, but rather administrative constructs with some market characteristics."[42]
- Those defending the current single-clearing price mechanisms must acknowledge that public policies and subsidies are antithetical to the efficient operation of any market. Thus, "any serious reconsideration of single-clearing price mechanisms cannot be confined to textbook economic theory, but must take into account how public policies have distorted the price mechanisms in RTO power markets that use marginal costs to determine outcomes and how these policies are likely to continue to do so."[43]

The Companies are closely following developments in RTOs - with a particular focus on MISO and PJM – in an attempt to better evaluate the financial, operational, and governance implications of joining one. As PJM states, "The findings of this study (Energy Transition in PJM: Resource Retirements, Replacements & Risks) 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,

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[38] Ibid, page 10. Also see Appendix 5 for Clark and Duane's paper "Rethinking and Restyling an Old Idea: A New Model of TRANSCO to Plan and Operate a Changing Grid" which suggests possible structural changes to RTOs.
[39] See Appendix 6 for complete paper.
[40] "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets," Energy Law Journal, Mark Christie, May 2, 2023, page 3.
[41] Ibid, page 4.
[42] Ibid, page 4.
[43] Ibid, page 4.

and the urgency for coordinated actions to shape the future of resource adequacy."[44] The Companies anticipate that the stakeholder process will likely make it challenging for PJM (and MISO) to quickly address the multitude of issues and challenges created by the clean energy transition.

Section 5: Anticipated Scope of 2024 RTO Membership Analysis to Be Filed with 2024 IRP

As was discussed in Section 4, the current state of flux in MISO and PJM market designs, rules, and tariffs make it difficult to reliably and confidently model the financial implications of future RTO membership. However, the Companies recognize that decisions must be made under uncertainty. Therefore, they are planning to perform an expansive, multi-faceted RTO analysis as part of their upcoming 2024 IRP. In addition to the usual analytics contained in past RTO membership reports, the scope of the 2024 RTO Membership Analysis will consider, among other items:

- Stakeholder processes in PJM and MISO and how they might differ from the Companies' decision-making processes as a standalone Balancing Area ("BA");
- Alternative capacity market designs and capacity accreditation methods;
- EPA's final 111 rules (expected in April 2024) and their possible impacts on RTO resources and the Companies' potential resource plans;
- The pros and cons of operating in PJM under Fixed Resource Requirements versus the Base Residual Auction;
- MISO's and PJM's regional transmission projects and their potential costs and benefits;
- The Companies' possible energy hedging activities and the use of other market mechanisms (e.g., ancillary services and financial transmission rights); and
- The Companies' planning and operational activities in an RTO and how they would contrast to those activities as a standalone BA.

This list is not intended to be exhaustive but indicates the expansive scope that will be included in the 2024 RTO Membership Analysis to address in reasonable detail the multitude of issues associated with considering RTO membership in today's environment. As the Companies have stated on numerous occasions, they are not opposed to RTO membership, but because it is likely a one-way option, exercising that option should only be done when it is clearly in the best long-term interest of customers.

Section 6: Update on SEEM Activities

The Southeast Energy Exchange Market ("SEEM") has been operational for almost one year, and it has been beneficial for the Companies' customers.[45] The Companies have been active SEEM participants, accounting for 11% of total SEEM transactions through August 2023. From inception through September 2023, the Companies have sold 51,055 MWh at an average price of $48.93/MWh and purchased 8,658 MWh at an average price of $15.27/MWh. The resulting off-system sales ("OSS") margins and purchase power savings have benefited customers through the Fuel Adjustment Clause ("FAC"). Indeed, the Companies estimate that customers have benefited by approximately $1,008,000

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[44] Energy Transition in PJM, page 17.

[45] See Southeast Energy Exchange Market (southeastenergymarket.com) for more information on SEEM and Appendix 7 for August 2023 audit report.

since SEEM's inception, which is nearly *twelve times* the estimated cost of SEEM participation during that period ($85,000).[46]

The Companies seek to participate in every 15-minute market and have a systematic process that determines the Companies' incremental costs and volume available for sale and the decremental costs and volumes for purchase. Note that this process is similar to that used for making "over-the counter" off-system sales and purchases from MISO, PJM, and TVA. See Appendix 8 for a detailed description of the Companies' SEEM bid/offer process.

Finally, it is important to note that SEEM continues to operate notwithstanding recent SEEM-related orders issued by the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") remanding certain SEEM matters to the Federal Energy Regulatory Commission ("FERC"). Only FERC can change open access transmission tariff ("OATT") rates related to SEEM's operations ("SEEM Tariff Rates"). Thus, the D.C. Circuit's recent actions do not immediately affect SEEM's current operations. The Companies will continue to monitor SEEM developments and seek to use their SEEM membership to customers' benefit whenever and as long as possible.

<u>Section 7: De-pancaking Litigation Update</u>

The Companies currently provide merger mitigation de-pancaking ("MMD") credits to certain entities importing from MISO under Transition Mechanism Agreements currently on file with FERC. The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO. See, E.ON U.S., LLC, et al., Docket No. ER06-1279-000. The Companies received FERC approval to eliminate MMD, but subject to the implementation of a transition mechanism for certain power supply arrangements.[47] The transition mechanism agreements are currently in effect, under which the Companies must still provide certain credits for MISO transmission charges. A recent decision from the D.C. Circuit Court of Appeals largely affirmed the FERC's analysis in the 2019 Removal Order, but ultimately vacated the decision and remanded the matter back to FERC.[48] In its order on remand, FERC reversed its decision allowing for the termination of MMD but did not take action to cancel or terminate the Transition Mechanism Agreements.[49] The Companies have requested rehearing of FERC's remand order, which was denied by operation of law on July 17, 2023, and filed an appeal. FERC has indicated in its filings before the D.C. Circuit Court of Appeals that it intends to issue a substantive order on rehearing before November 13, 2023. Due to the status of the ongoing litigation on MMD, it is not possible to identify how the Companies' MMD obligation might be impacted by RTO membership or to quantify such hypothetical impact. The

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[46] See Appendix 7 for the most recent SEEM Independent Market Monitor monthly report, which provides various SEEM market data.

[47] *Louisville Gas & Elec. Co.*, 166 FERC ¶ 61,206 ("2019 Removal Order"), *order on reh'g & clarification*, 168 FERC ¶ 61,152 (2019), *aff'd sub nom. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162 (D.C. Cir. 2022) ("KYMEA").

[48] The D.C. Circuit stated, "In short, the Commission's conclusion that sufficient competition would continue after [MMD] was based on substantial evidence from which it drew sensible inferences employing its expert knowledge of electricity markets. That is the 'kind of reasonable agency prediction to which we ordinarily defer.'" However, the D.C. Circuit faulted FERC for failing to evaluate the impact of the removal of MMD on rates and vacated the decision. *KYMEA,* 45 F.4th at 177.

[49] *Louisville Gas & Elec. Co.*, 183 FERC ¶ 61,122 (2023).

Companies will revisit the potential impact of and to MMD in performing the RTO analysis for the 2024 IRP.

Section 8: Conclusion

The Companies continue to be open to possible future RTO membership. The Companies are actively monitoring market developments in MISO and PJM to help inform their modeling efforts and other analysis that they plan to file with the Commission as part of their 2024 IRP filing. That filing will also address the Commission's final order in the currently pending CPCN proceeding, both in terms of the Companies' future generation portfolio and regarding any direction or requirements the Commission provides in that order for future RTO membership analyses. But it is clear based on the best information currently available that RTO membership is not advisable for the Companies' customers at this time.

APPENDICES

Appendix 1 - Ensuring a Reliable Energy Transition – PJM, 2023

Appendix 2 - Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 2023

Appendix 3 - Private Equity in PJM: Growing Financial Risks, Institute for Energy Economics and Financial Analysis, August 2023

Appendix 4 - Stretched to the Breaking Point – RTOs and the Clean Energy Transition, Tony Clark and Vincent Duane, July 2021

Appendix 5 - Rethinking and Restyling an Old Idea – A New Model of Transco to Plan and Operate a Changing Grid, Tony Clark and Vincent Duane, February 2022

Appendix 6 - It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets, Mark C. Christie, Energy Law Review, May 2, 2023

Appendix 7 - SEEM Audit Report prepared by Potomac Economics, August 2023

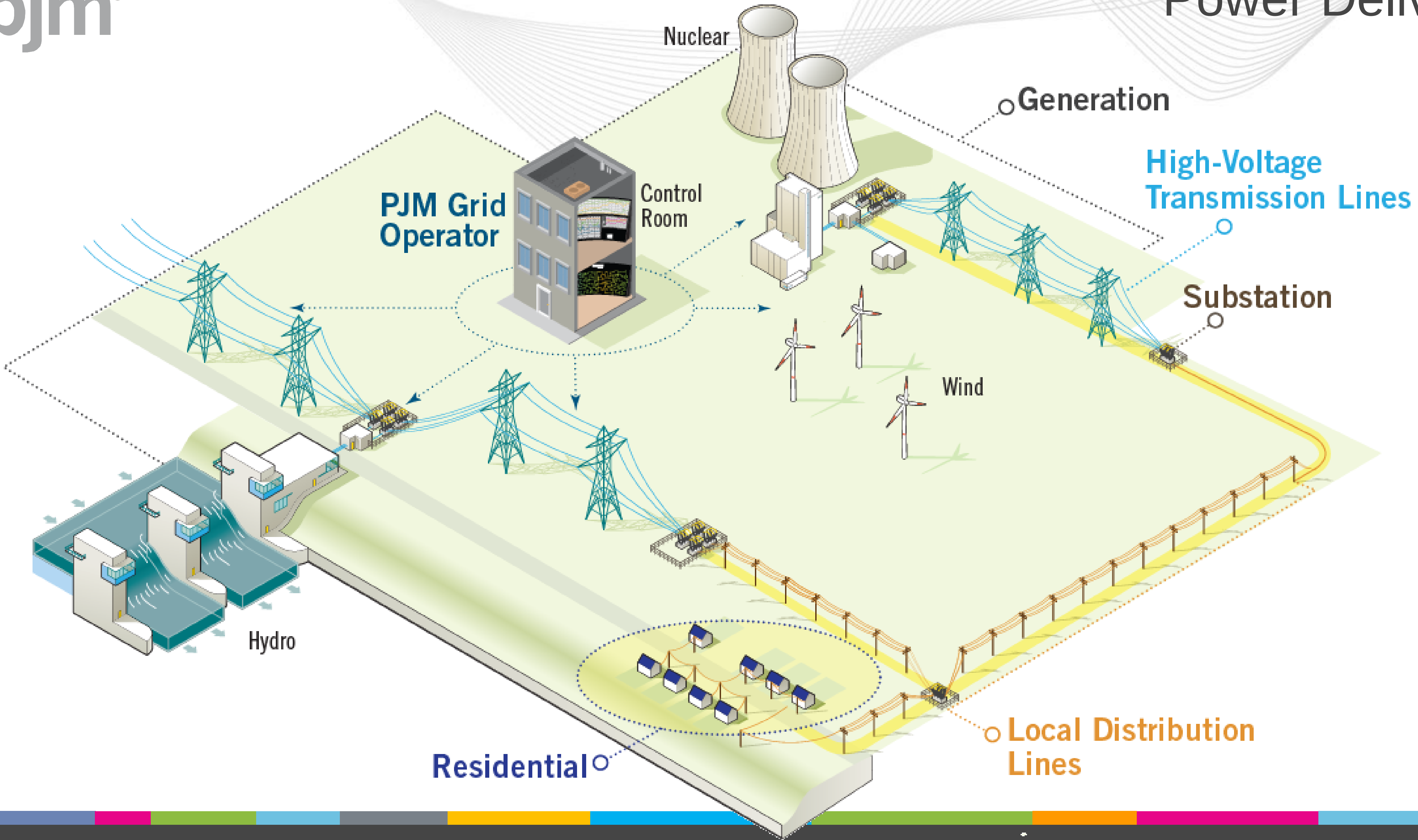
Appendix 8 - Companies' SEEM Bid/Offer Process, July 2023

Appendix 1

Ensuring a Reliable Energy Transition

Asim Z. Haque
Vice President, State and Member Services
PJM Interconnection, LLC

Power Delivery



RELIABILITY

Markets
- Energy
- Capacity
- Ancillary services

Operations
- Grid operations
- Supply/demand balance
- Transmission monitoring

Regional Planning
- 15-year outlook

PJM's Role as a Regional Transmission Organization

PLANNING

Planning for the future like...

OPERATIONS

Matches supply with demand like...

MARKETS

Energy Market Pricing like...

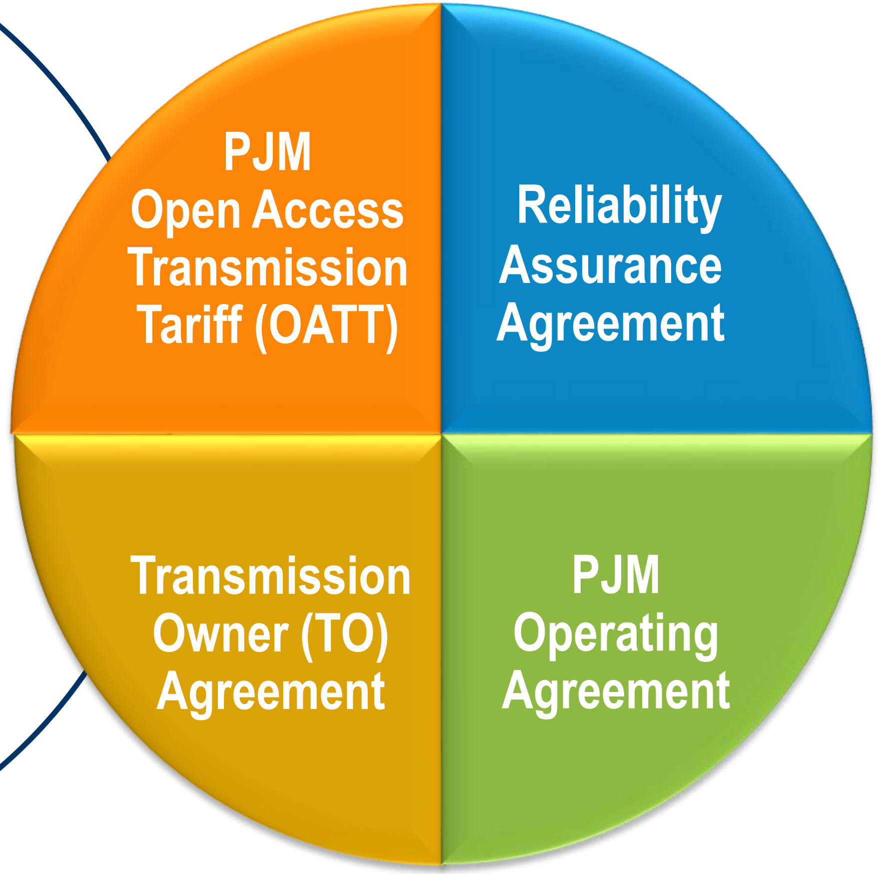
How Is PJM Different from Other Utility Companies?

PJM Does:

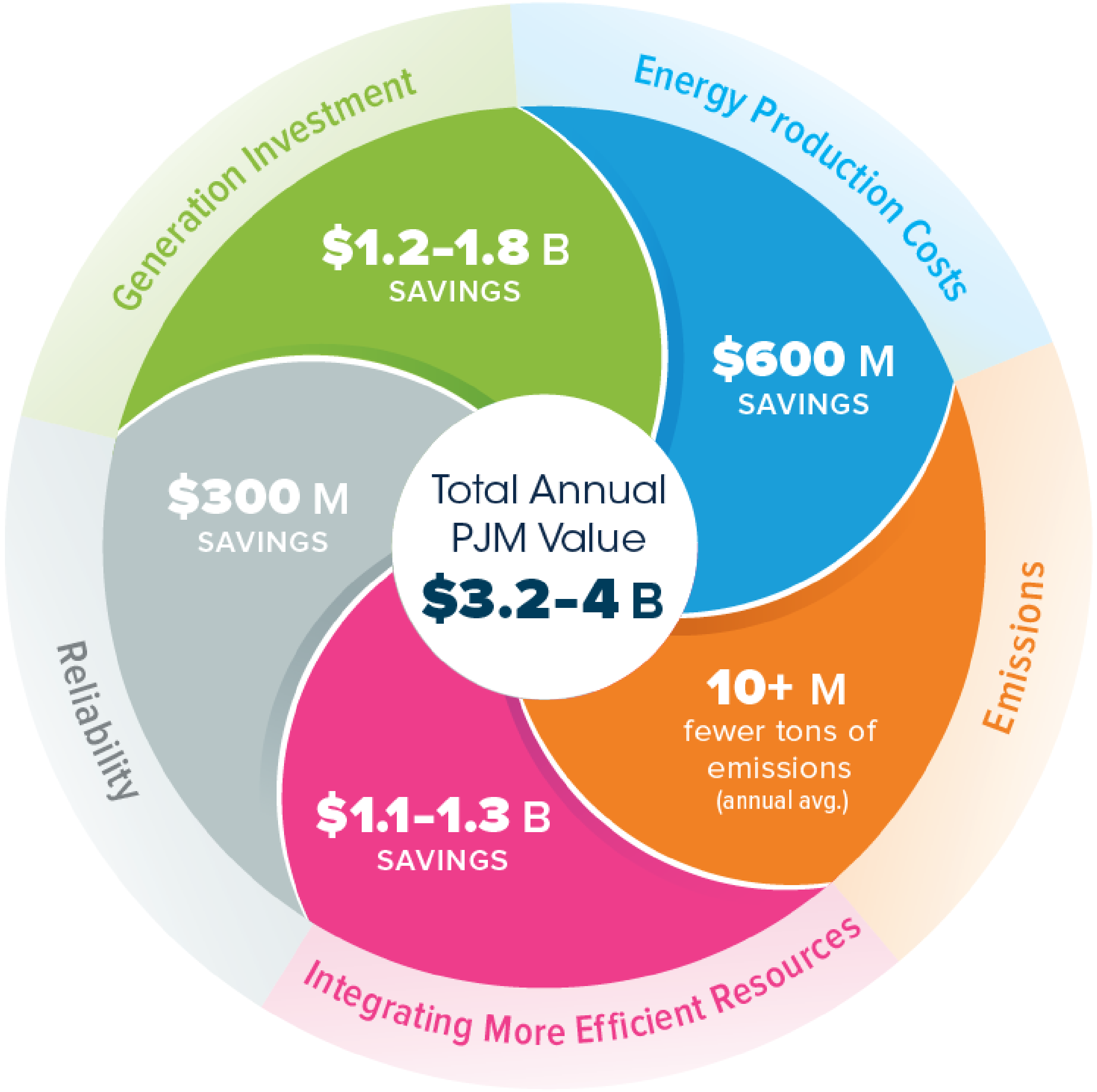
- Direct operation of the transmission system
- Remain profit-neutral
- Maintain independence from PJM members
- Coordinate maintenance of grid facilities

PJM Does *NOT:*

- Own any transmission or generation assets
- Function as a publicly traded company with shareholders and concerns around "earnings"
- Perform maintenance on generators or transmission systems (e.g., repair power lines)
- Serve or direct any end-use customers (retail)



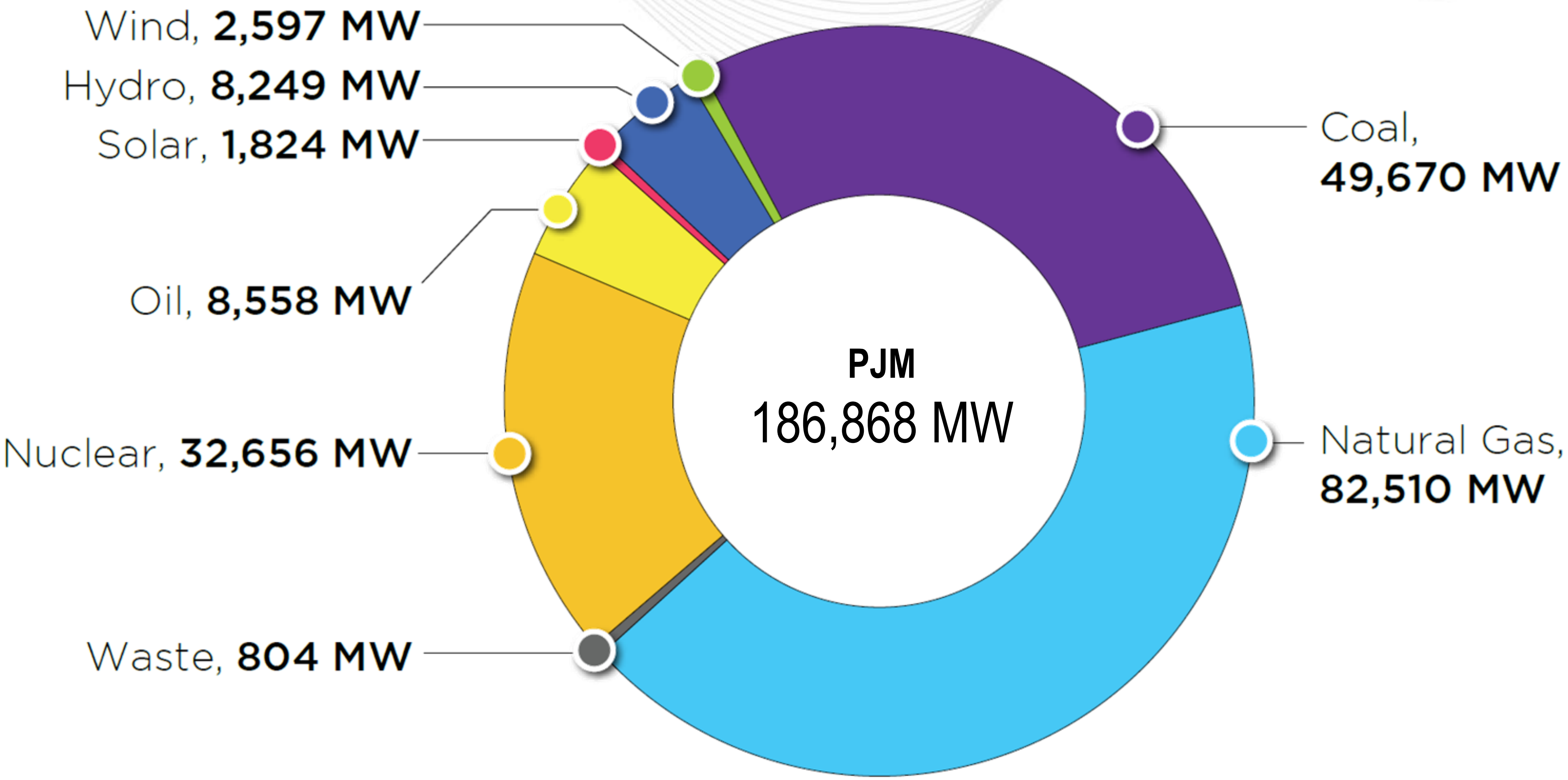
Value Proposition



All numbers are estimates.

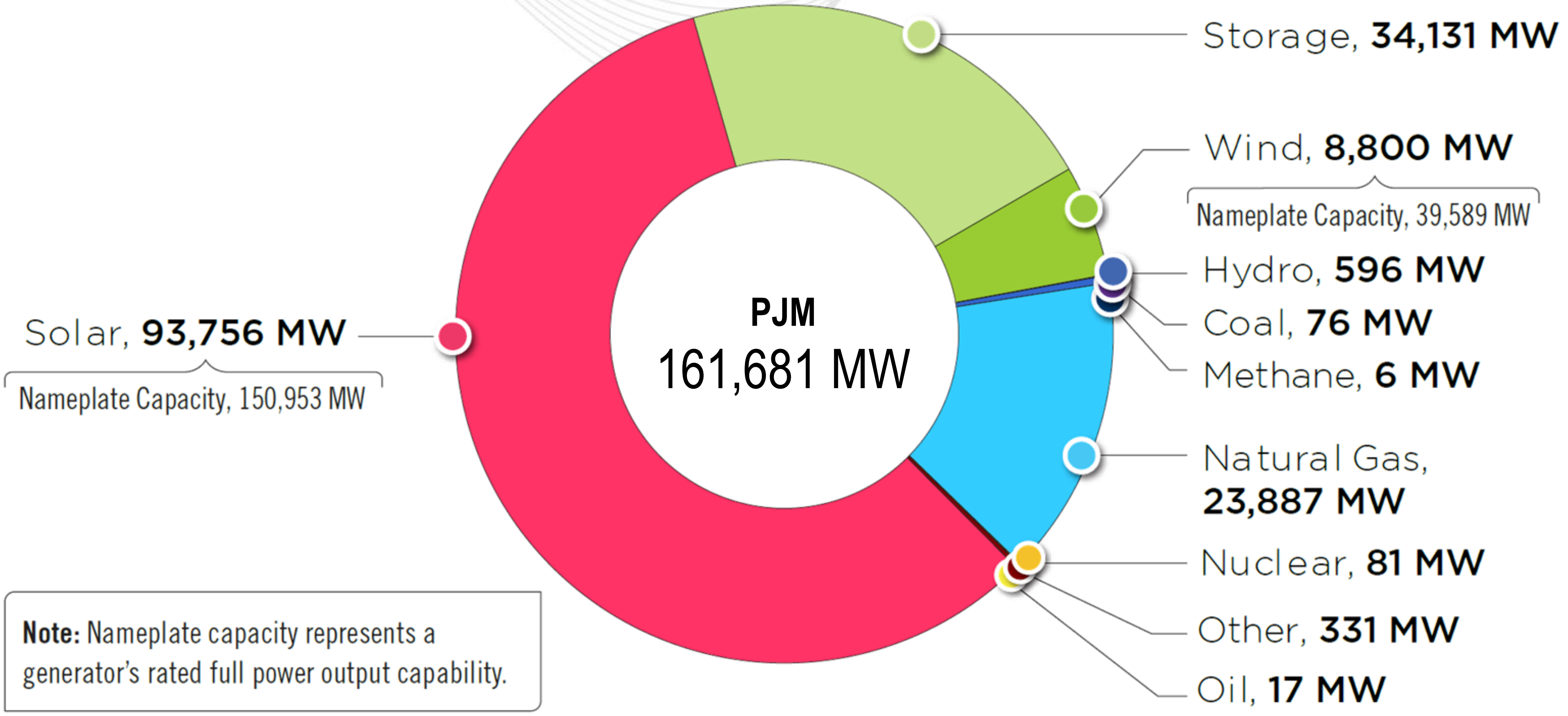
PJM – Existing Installed Capacity

(CIRs – as of Dec. 31, 2021)



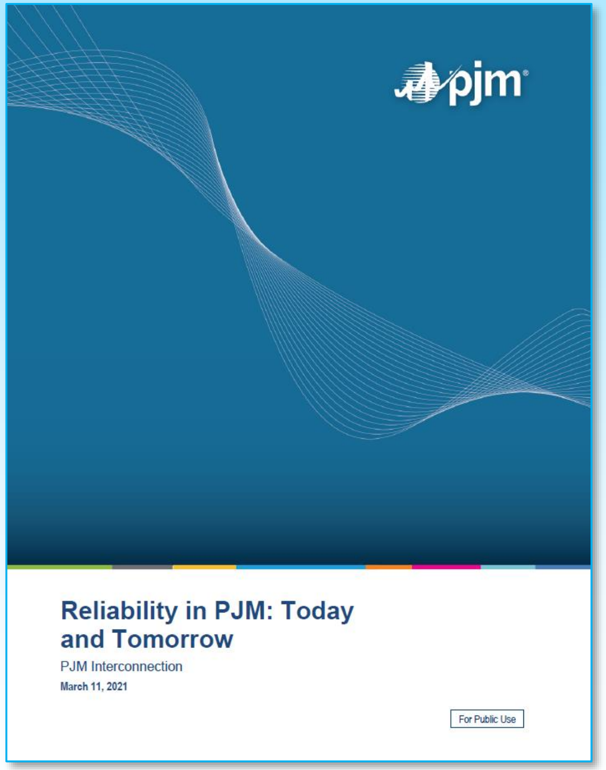
PJM – Queued Capacity (MW) by Fuel Type

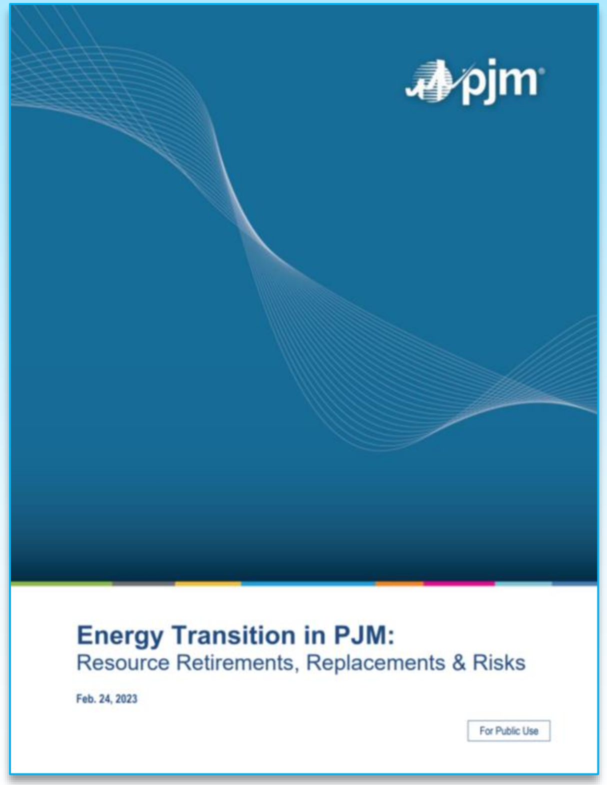
(Requested CIRs – as of Dec. 31, 2021)

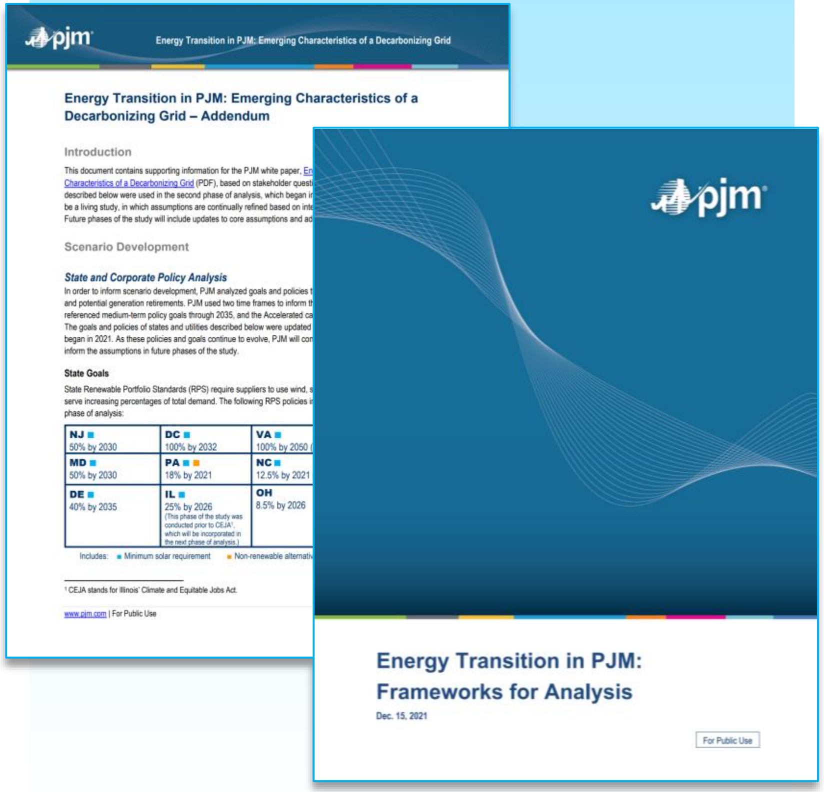


Note: Nameplate capacity represents a generator's rated full power output capability.

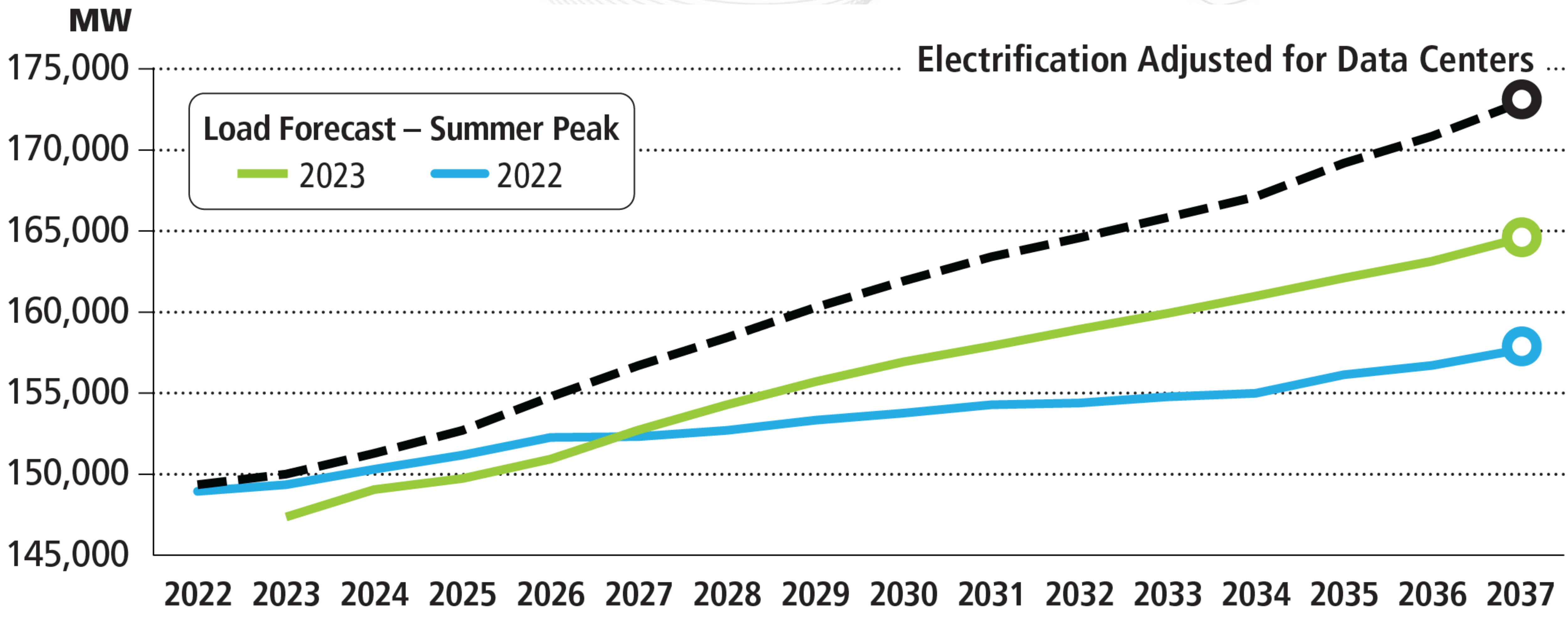
Reliability Papers and Studies



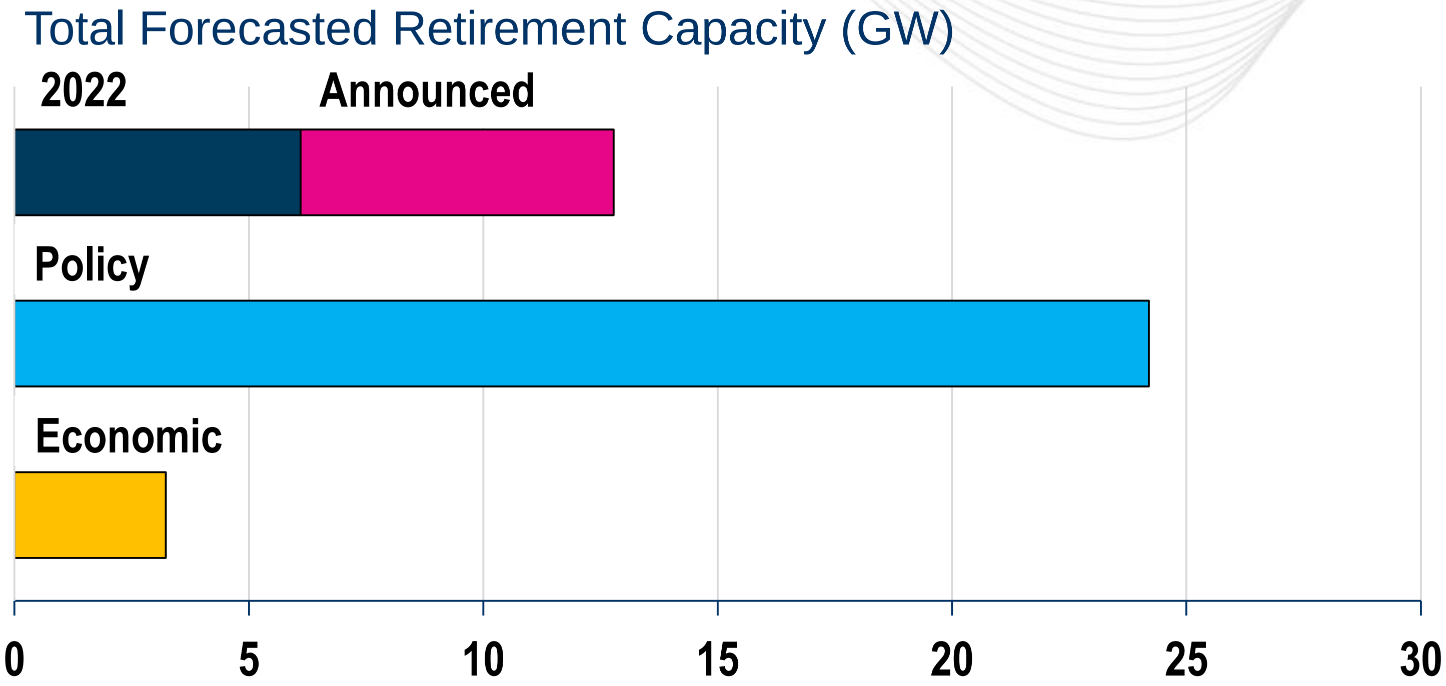




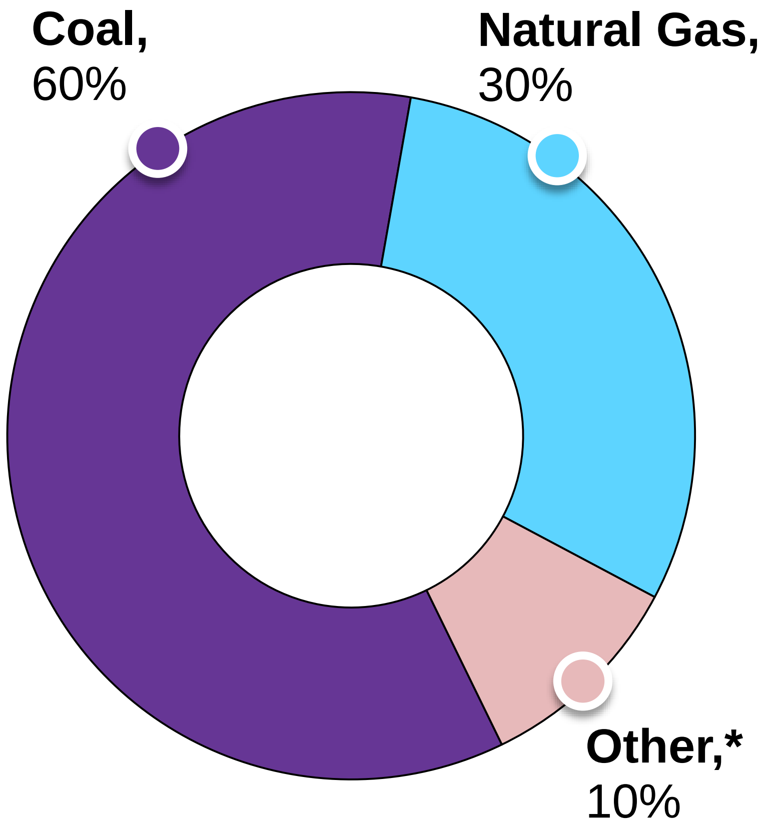
Load Growth Forecasts



Forecasted Retirements (2022–2030)

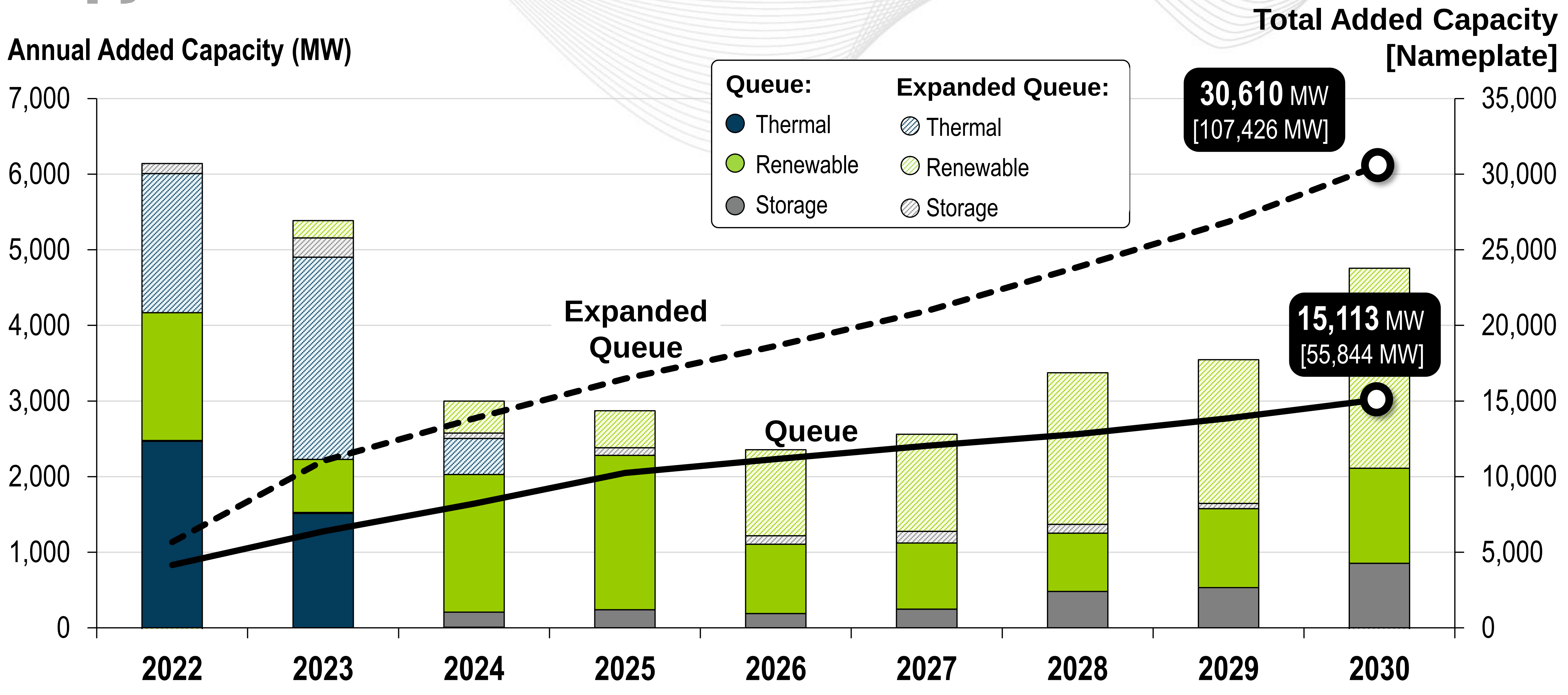


This **40 GW** represents
21% of PJM's current
192 GW of installed generation



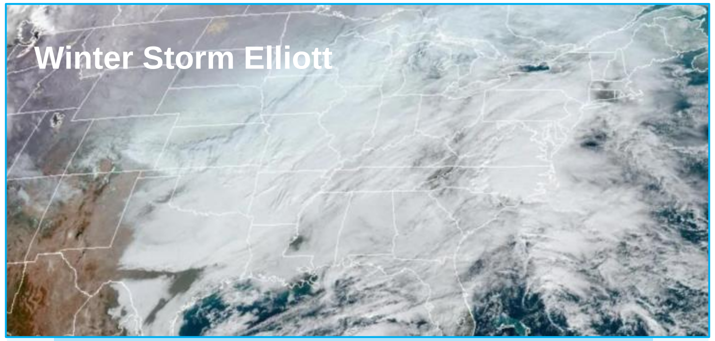
Other includes diesel, etc.

PJM Forecasted New Entry (2022–2030)

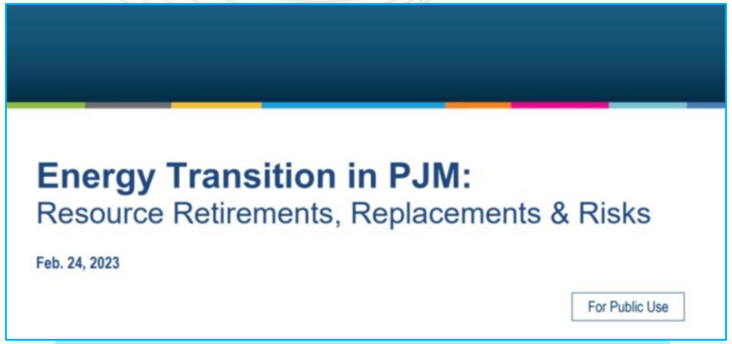


What Problem(s) Are We Solving For?

RELIABILITY



The PJM fleet has adequate resources and enough essential reliability services, but we need our generators to perform when called upon.


Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

Generation retirements may outpace new entry with a simultaneous likelihood of load increasing, thereby creating resource adequacy concerns.

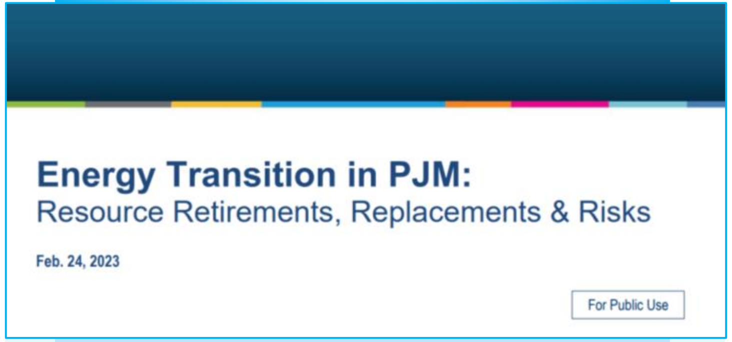

Energy Transition in PJM:
Frameworks for Analysis

Dec. 15, 2021

For Public Use

We will continue to need some amount of thermal generation to provide certain essential reliability services until a replacement technology is deployable at scale.

Our Reliability Concerns

The Immediate Concern	**The Near-Term** Concern	**The Upcoming** Concern
	 **Energy Transition in PJM:** Resource Retirements, Replacements & Risks Feb. 24, 2023 For Public Use	 **Energy Transition in PJM:** **Frameworks for Analysis** Dec. 15, 2021 For Public Use
Support Resource Performance	**Ensure** Resource Adequacy	**Maintain & Attract** Essential Reliability Services

Initial Actions To Support Reliability

CIFP/RASTF Priorities

Reserve Certainty

Load Following/ Dispatchability

Short-Term Forecasting

Proactive Planning: LTRTP

Proactive Planning: Resilience

Proactive Planning: Interregional

LDA Modeling

RMR Improvements

Policy Reliability Safety Measures

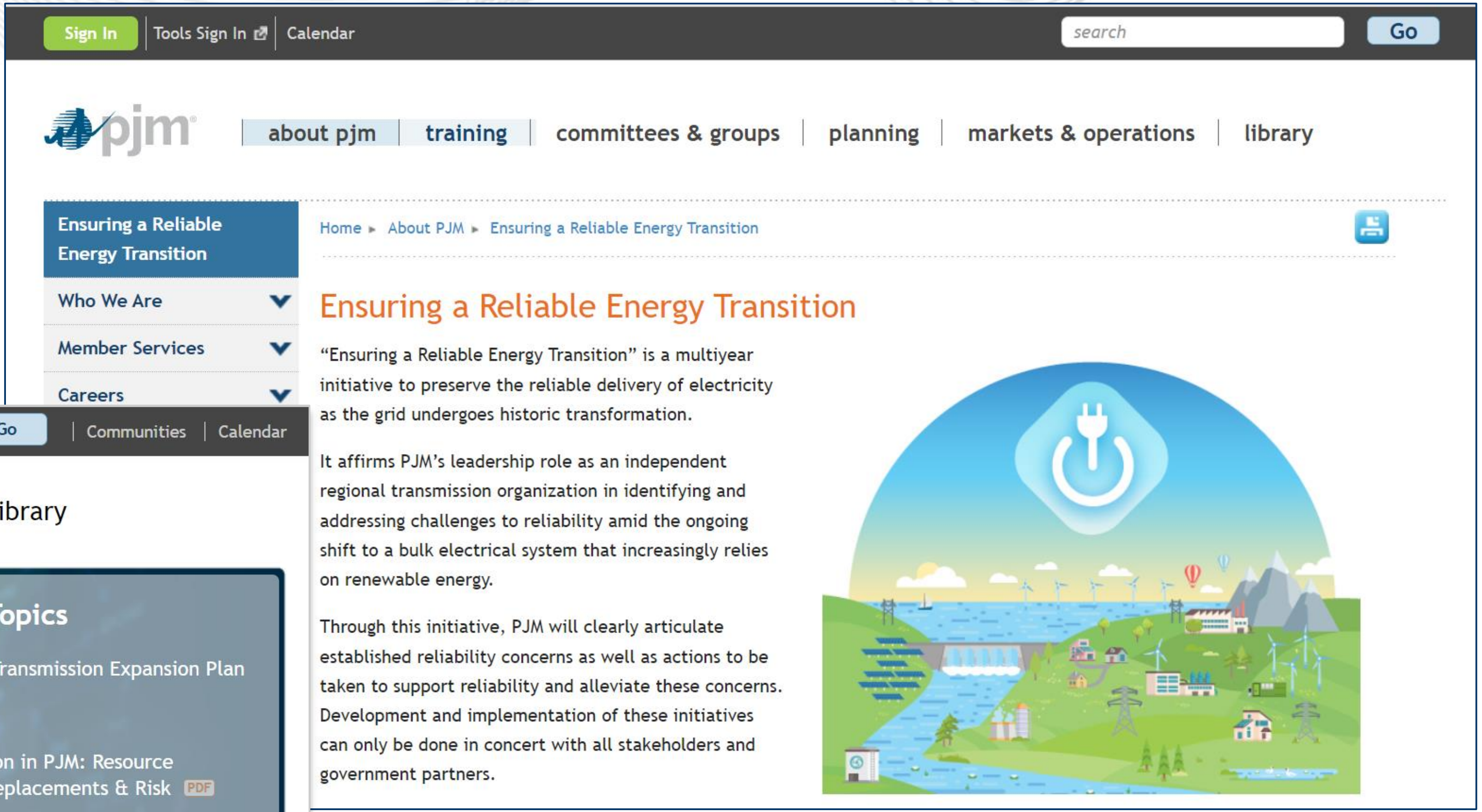
Continued Queue Improvements

Energy Assurance

Gas/Electric Coordination

Elliott Placeholder

Ensuring a Reliable Energy Transition



Appendix 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).

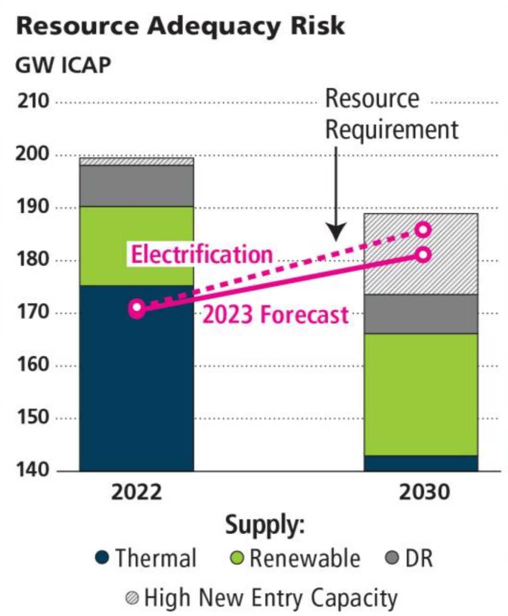
The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder 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]

[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	**New Entry Wind/Solar**[6]	**New Entry Standalone Storage**	**New Entry Thermal**	**Load Growth**
40 GW **60% Coal** **30% Natural Gas** **10% Other**	**Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**Low =** 3 GW **High =** 4 GW	**Low =** 4 GW **High =** 9 GW	**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.

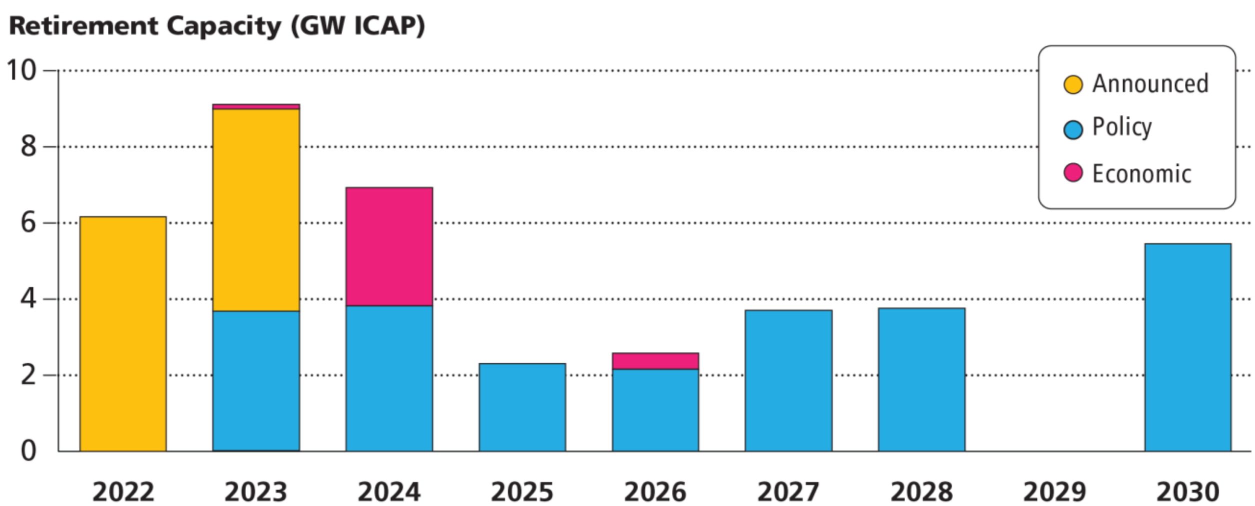
Supply Exits

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.

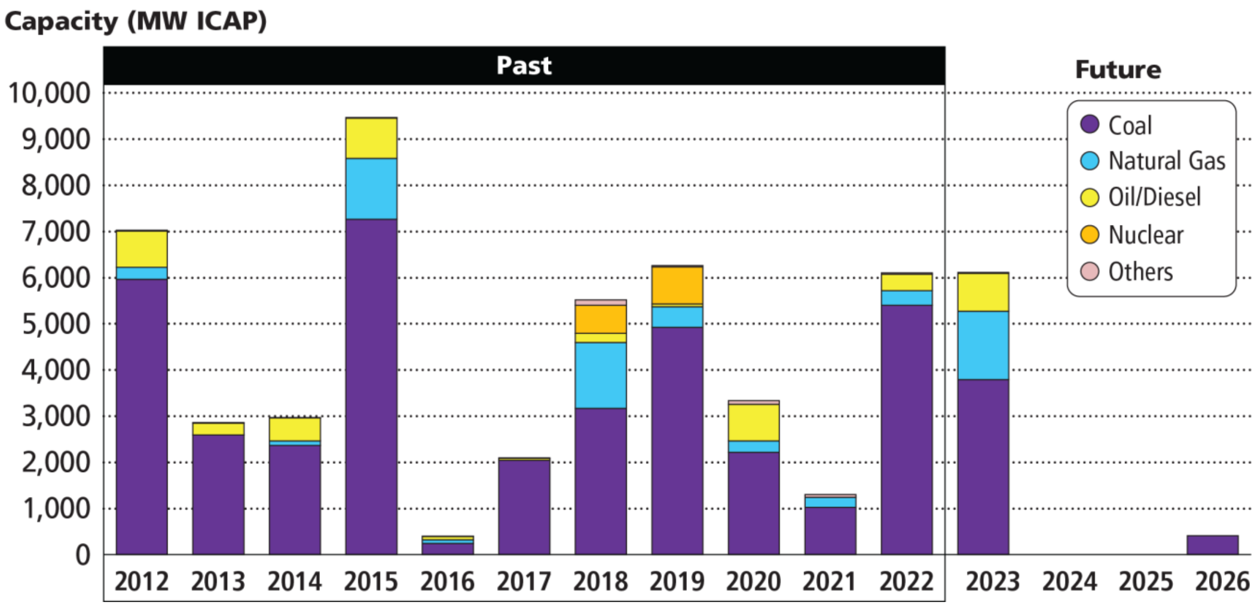
Announced Retirements

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:

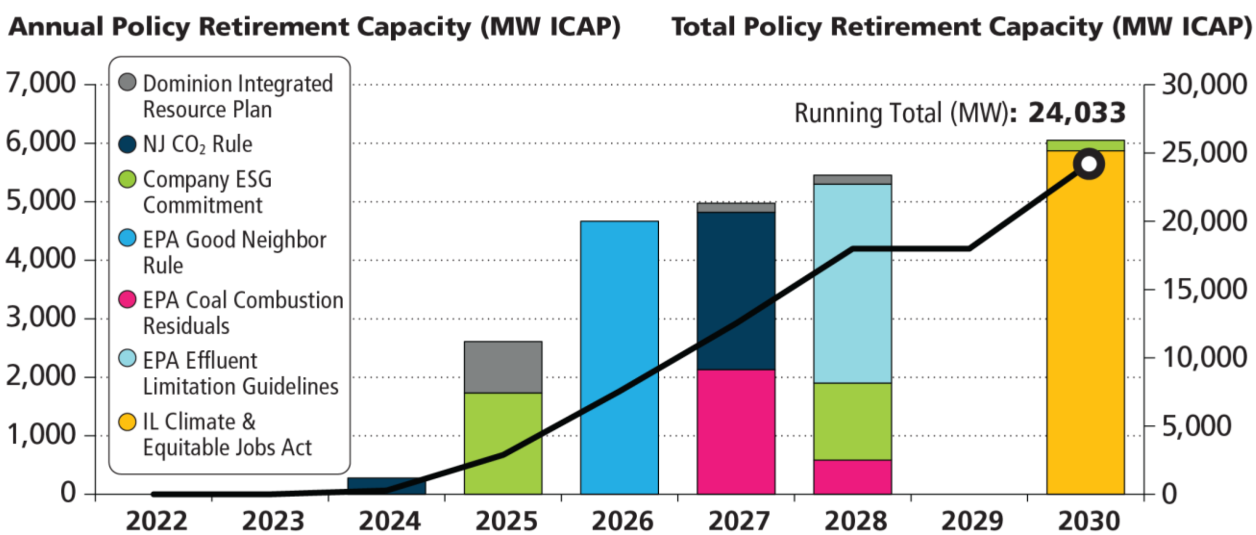
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

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**.

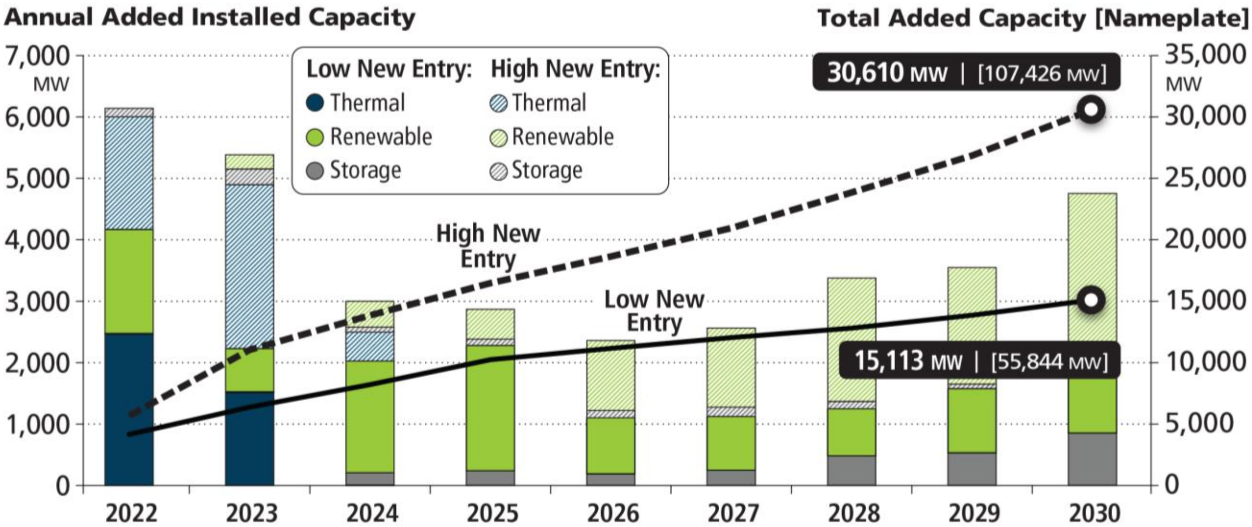
Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates 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.

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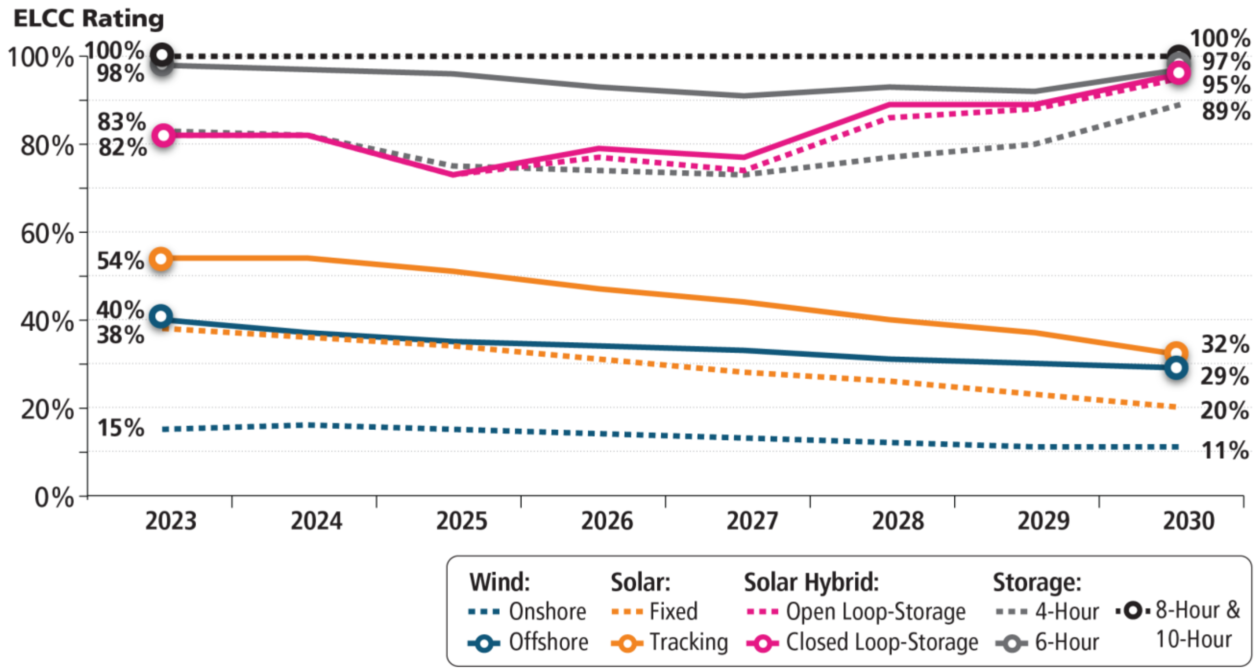
[21] Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

[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**.

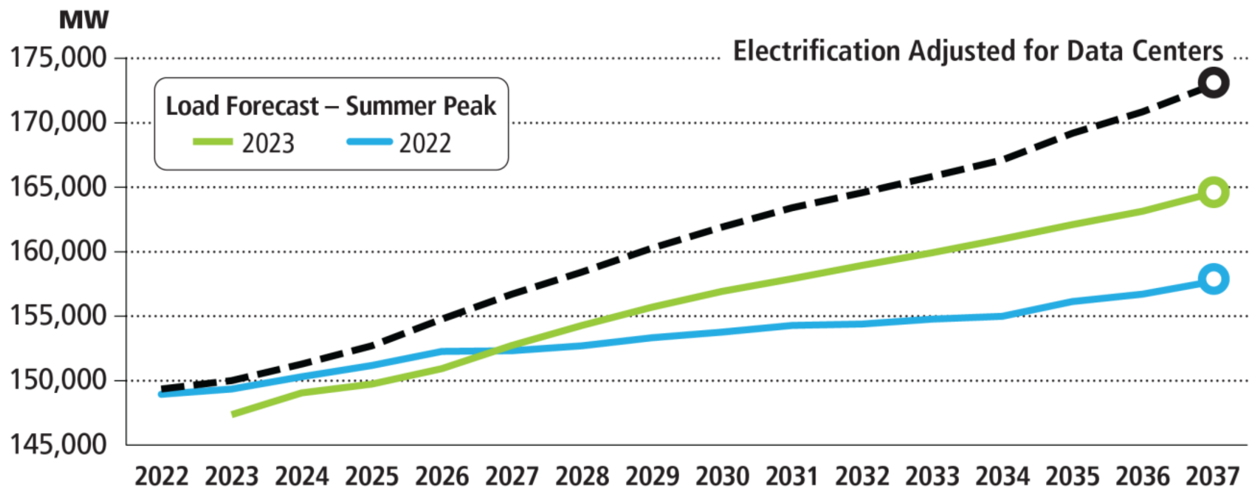
[23] See Loudoun County Department of Economic Development, 2023.

[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

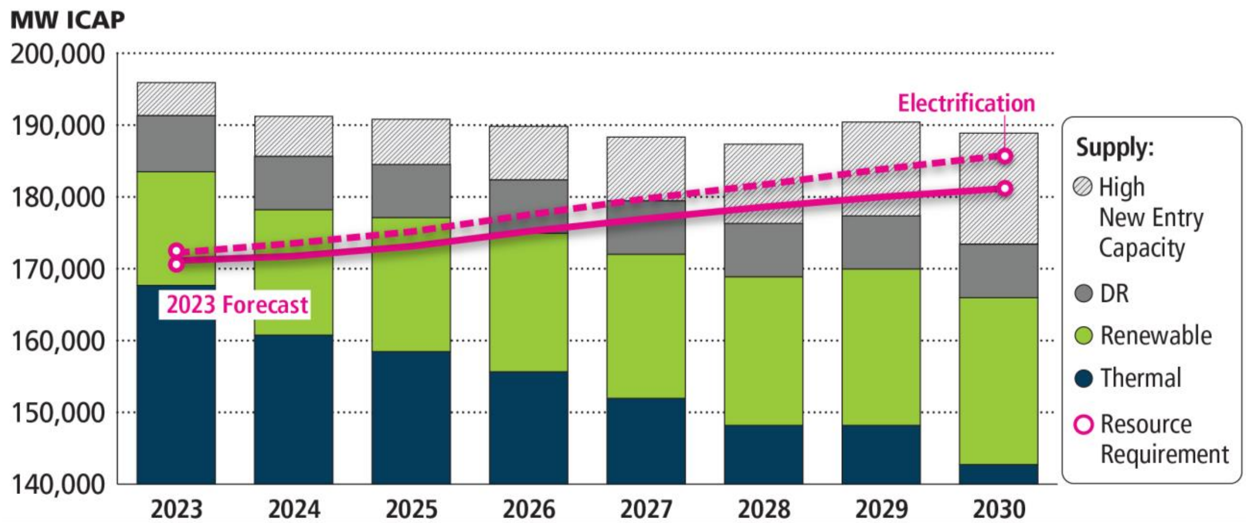
Table 1. Reserve Margin Projections Under Study Scenarios

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.

Appendix 3

Institute for Energy Economics and Financial Analysis

Private Equity in PJM: Growing Financial Risks

Dennis Wamsted, Energy Analyst

August 2023

Contents

Figures and Tables

Key Findings

The relatively stable and high capacity payments from the system operator that have enabled the buildout of so much privately owned fossil-fuel generation capacity in PJM have disappeared in the last three years.

Low capacity auction payments, coupled with the recent sharp runup in interest rates, have worsened the economic outlook for new PJM projects and made merchant projects more economically risky.

The fines from Winter Storm Elliott have pushed some existing plants into bankruptcy while forcing others to seek capital infusions from their private equity sponsors.

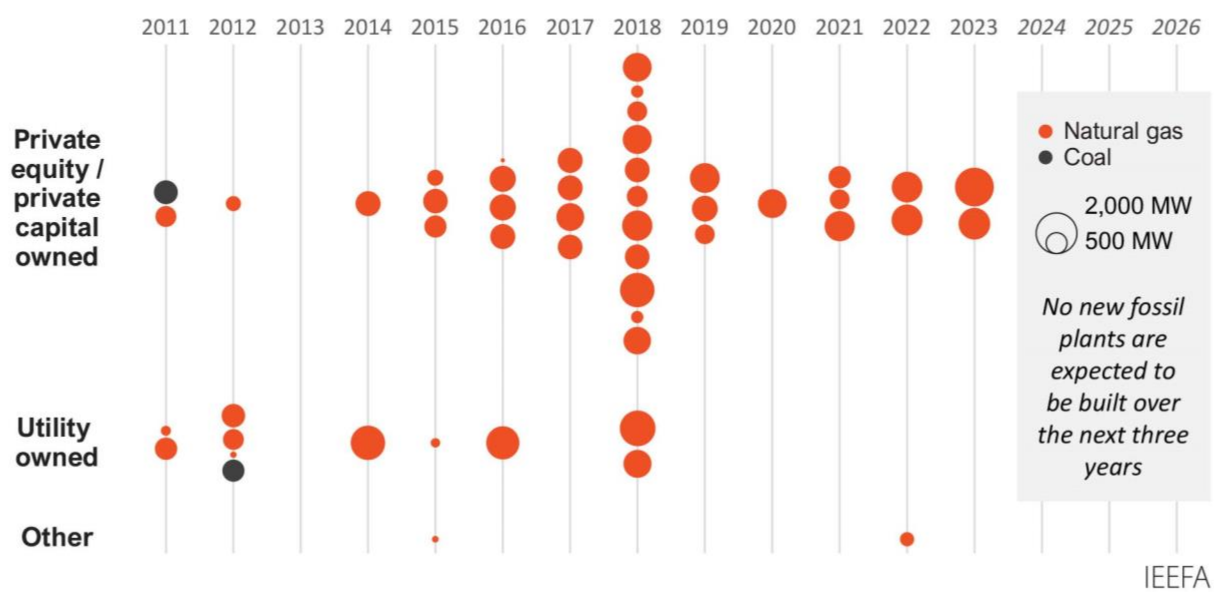
The 2010s saw a massive buildout of new capacity with relatively low risk, but the situation today is reversed, and it is a new, much riskier situation for private equity and private capital in the PJM market.

Executive Summary

Private capital, particularly difficult-to-track private equity (PE) investment, has reshaped the PJM power market in the past decade. PJM data shows that 35,515 megawatts (MW) of combined cycle gas capacity have been built in the 13-state regional system since 2011, reflecting the impact of the fracking revolution that brought plentiful, low-cost gas supplies to the market. PE and other private sources developed more than 80% of the total—28,815MW.

This gas-driven growth, coupled with significant PE investment in the region's coal-fired power plants, has transformed the ranks of PJM's largest generators. As recently as 2017, the five largest capacity owners were all regulated publicly traded companies: American Electric Power, Dominion Energy (the parent of Virginia Power), Exelon (the parent of Commonwealth Edison), FirstEnergy and NRG Energy. Today, three of the largest generators are private firms—ArcLight with 14,230MW of operating capacity, LS Power (10,803MW) and Talen (the former subsidiary of Blackstone that recently emerged from bankruptcy under new ownership), with 10,370MW.[1] Beyond these three majors, there are a host of private and PE firms that own from 1,000MW to 5,000MW of capacity. Together, private capital now owns roughly 60% of the fossil-fuel fired generation capacity in PJM.

Figure 1: Private Equity Fossil Fuel Capacity Has Soared in PJM Since 2011



[1] The data is correct as of Dec. 31. 2022. State of the Market Report for PJM-2022. Monitoring Analytics. March 9, 2023. P. 314.

Ownership status is important. Utilities are overseen by state regulators who have a vested interest in keeping costs for ratepayers in check; private capital is largely free from that oversight. Utilities, as well as publicly traded independent power producers, are also required to file regular financial reports with the Securities and Exchange Commission; private capital, by and large, is not. These differences largely shield private firms from public pressure and regulatory and financial oversight.

In this three-part report, IEEFA examines the increasing risk environment in PJM, the nation's largest power market.

The first section takes a close look at the rising financial risks now facing PE and other private firms—risks that contrast sharply with the previous strong, steady growth of the 2010s. That decade-long growth spree was underpinned by relatively high and relatively stable capacity prices; those prices have collapsed, squeezing existing and new developers alike. The fallout from the Christmas storm that rolled across the eastern half of the country in 2022 (Winter Storm Elliott) has further undercut the finances of many market participants. First, PJM came out swinging regarding the unavailability of thousands of megawatts of fossil fuel capacity during the event, levying fines of almost $2 billion for non-performance during the December storm. Second, the grid operator is now evaluating new market structures that could cut into future capacity payments for fossil fuel generators while boosting renewable payouts.

The second section will focus on the limited partners. These pension and retirement funds have poured money into the PE sector in the past decade, and have generally been well rewarded for their investments. But the changing regional power environment is likely to shift the outlook for outside investors by lowering annual returns, raising investment risks, or both. This second section will pay particular attention to the fallout from bankruptcy filings, in which funds and other private entities end up owning assets they may not want. For example, Nuveen/TIAA found itself in that situation following the 2020 bankruptcy restructuring of FirstEnergy Solutions, which became Energy Harbor.

The final section will examine the risks posed by PE's relative immunity from oversight and public pressure, a growing threat for the localities where the plants operate. PE firms push risks onto the communities. When their plants are no longer economic, PE generators can simply decide to close up shop and get out, leaving unprepared localities facing significant economic dislocations from job and tax losses. This exact scenario played out in the spring at the Homer City power plant in Pennsylvania as we will examine, but that community is not likely going to be the last unless local leaders begin planning now for the coming transition.

Similarly, PE's lack of public accountability creates the very real possibility that efforts to curb regional carbon dioxide emissions will become more difficult in the years ahead. The fossil fuel plants owned by PE firms and other private capital now account for more than 50% of the region's annual power-related carbon dioxide (CO_2) releases, and that percentage is likely to grow. But the sector's lack of transparency shields it from the types of public pressure that have helped convince publicly traded electric utilities to move, however haltingly, toward decarbonization efforts.

Financial Risks

The Capacity Payment Collapse

The decade-long construct that enabled the buildout of so much private equity and other privately owned generation capacity in PJM hinged on one key factor—relatively stable and high capacity payments from the system operator. These payments, essentially an insurance policy bought by the system operator to guarantee power is available to the market when needed, meant fossil fuel plant owners would get steady payouts regardless of whether they were generating power or not. This essential ingredient, which helped insulate generators against low market prices for power in the competitive market, has disappeared in the last three years.

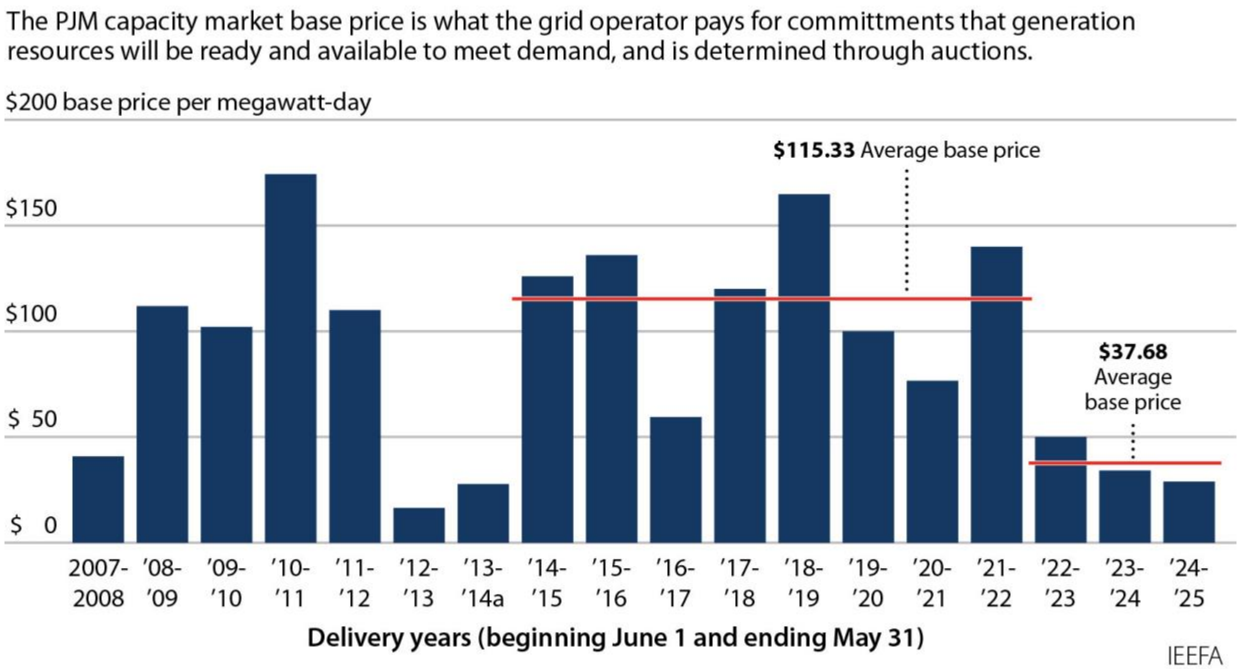
From 2014 through the 2022 capacity auction, the clearing price in the region averaged $115.33 per megawatt-day (MW-day),[2] making it relatively easy for developers to secure financing. Lenders were willing to back projects knowing that these annual capacity payments could be used to cover debt service needs. And that, coupled with the steady availability of fracked gas, set off a torrent of new construction: PJM data shows that more than 45,000MW of generation capacity, more than three-quarters gas-fired and most of that privately financed, were built from 2011-22.

But both existing plant owners and new project developers now face an entirely different financial outlook.

Capacity bids for the 2022-23 delivery year (PJM runs on a June 1-May 31 timeline) dropped to just $50/MW-day and they have continued their downward trend since. In the last three auctions, capacity bids have averaged just $37.68/MW-day. This has changed the economic outlook for new PJM projects. The prospect of lower capacity payments for developers is likely to prompt lenders to raise rates because of concerns about higher repayment risks. That, coupled with the recent sharp runup in interest rates, will boost debt service costs for developers, making merchant projects more economically risky. The impact of these changes is already showing up in canceled projects and financial distress among some generators.

[2] PJM has different regions that clear at different capacity auction prices. The prices used here are from what is known as the rest of PJM and encompasses the bulk of the system's geographical footprint. Other, smaller regions, often with transmission limitations, tend to trade at higher capacity clearing prices. The differences will be noted in the text, as necessary.

Figure 2: PJM Capacity Prices No Longer a Bonanza



Source: PJM.

When Bechtel canceled its plans to develop the 1,240MW Renovo combined cycle gas plant in Pennsylvania in April, it attributed the decision to concerns about securing the project's air permit. However, it is extremely likely that the recent decline in capacity payments and higher borrowing costs were also factors in the decision-making process.

Operating plants, particularly seldomly used peaking plants, have also been hit hard by the decline in capacity prices.

One of the first to fall was Heritage Power, which filed for bankruptcy protection on Jan. 24. In the company's filing, David Freysinger, the CEO of Heritage's then-parent company GenOn Holdings, highlighted the sharp decline in Heritage's capacity payments as a driving force behind the decision: "The debtors capacity revenues declined from $112.9 million for the 2021/2022 year, which began June 2021, to a projected $69.5 million for 2022/2023 and $37.5 million for 2023/2024."[3]

Heritage, which owns 16 gas- and oil-fired units in Ohio, Pennsylvania and New Jersey with a total generation capacity of 2,350MW,[4] was never going to be able to make up the lost revenue through additional energy sales. In 2022, the company's generating units only produced 1.8 million megawatt-hours (MWh) of electricity, representing a capacity factor of less than 9%. All told,

[3] Heritage Power bankruptcy filing. January 25, 2023. pp. 24-25.
[4] *Ibid*. p. 6.

Freysinger said, Heritage earned just $1.3 million in energy margin net of its hedges during the year—not even enough to cover its annual capital investments.

Prior to the bankruptcy, GenOn's two principal owners were Strategic Value Partners (SVP), which owned 58.2%, and funds managed by MacKay Shields, which owned 13.6%. SVP describes itself as "a global investment firm focused on distressed debt and private equity opportunities"; MacKay Shields is a wholly-owned subsidiary of New York Life Insurance Company.[5]

However, in an August filing with the Federal Energy Regulatory Commission (FERC), GenOn/Heritage said that under the terms of the pending bankruptcy reorganization plan the indicated owners (those expected to hold 10 percent or more of the equity of the new Heritage) would be: Funds affiliated with Avenue Capital Group, a New York-based PE firm; PGIM, a subsidiary of life insurance/investment firm Prudential Financial; Cross Ocean Partners, an investment firm headquartered in London; and J Aron, a commodities trading firm owned by The Goldman Sachs Group. Final ownership percentages will not be known until the reorganization plan is approved by the bankruptcy court, which is expected in October, and it is still possible that one or more of the current indicated owners will not end up owning more than 10 percent of the reorganized firm.[6]

While Heritage was the first, it may not be the last. The decline in the capacity market has raised concerns about several other existing projects, as highlighted in recent credit reports from Moody's Investors Service.

In July 2022, for example, Moody's downgraded the debt of Nautilus Power from B1, already a below-investment grade rating, to B3 and said the debt's outlook remained negative. According to Moody's, "Obligations rated B are considered speculative and are subject to high credit risk."[7]

Nautilus is controlled by The Carlyle Group and owns six power plants with a total capacity of 2,085MW. Three of the Nautilus units are in the PJM region—the 280MW Lakewood Energy plant, the 374MW Ocean Peaking Plant, and the 744MW Rock Springs facility. The other units are in ISO-New England, another region with capacity payments.

The three PJM plants are all located in the eastern region of PJM in an area known as the Eastern Mid-Atlantic Area Council (EMAAC); capacity prices there have been higher than PJM as a whole but have also declined significantly in the past three years. In 2021-22 the clearing price was $165.73/MW-day, while in the latest auction (for 2024-25) the price was $54.95/MW-day.

"The downgrade … reflects our view that declining capacity revenues in both PJM Interconnection and ISO-New England will pressure debt service coverage ratios and heighten refinancing risk for

[5] Triennial Market Power Analysis for Northeast Region of GenOn Energy Management, LLC, et al. under ER11-2508. PP. 3-4. Available for download at FERC's eLibrary
[6] Heritage Power, LLC, on behalf of its public utility subsidiaries under EC23-117. Available for download at FERC's e-library. PP. 16-29.
[7] Moody's Investors Service rating scale.

the project's term loan, which matures on 16 May 2024," wrote Gayle Podurgiel, a Moody's vice president. "The negative outlook reflects the project's challenges as it approaches its major debt maturity in less than two years, **considering its high reliance on capacity revenues to service this debt** [emphasis added]."[8]

In January, Moody's downgraded the debt of West Deptford Energy Holdings LLC from B2 to B3, voicing essentially the same concerns that it had with Nautilus. Like the Nautilus plants, West Deptford is located in the EMAAC area of PJM, which has seen capacity prices drop by more than $100/MW-day in the past three years.

"The rating downgrade to B3," Moody's said, "reflects our view that financial metrics will continue to underperform as low PJM capacity auction prices weigh on future cash flows in combination with continued weak energy margin contributions….

"Absent substantial market improvement, the project may struggle to generate sufficient cash flow to cover debt service in 2023 and 2024 under our current projections due to declining capacity prices, backwardated energy futures and $3.1 million of major maintenance planned in 2023."[9]

West Deptford Energy owns the 780MW West Deptford combined cycle gas plant in southern New Jersey. The plant is ultimately owned by LS Power, a private equity firm, and several other investors including Marubeni, Sumitomo and the Kansai Electric Power Company.

Moody's also raised concerns about PJM's recent capacity prices in a March analysis of the impact for merchant power generators in the region: "The weak auction results are credit negative for merchant power generators because they will reduce high-certainty cash flow and because lower capacity prices coupled with recent energy margin compression could erode profitability."[10]

Future Auctions, New Queue Rules Raise Gas Risks

The uncertainty surrounding future capacity auction results will make it more difficult for new plants to move forward with planning, permitting and, particularly, financing. Selling a banker or other financier on a project with expectations of capacity prices above $100/MW-day is undoubtedly easier than pushing the same project with prices below $50/MW-day.

Earlier this year, FERC approved PJM's plan to push its scheduled capacity auction for the 2025-2026 delivery year until June 2024. Following that, PJM plans to hold auctions every six months, bringing it back to the preferred three-year-ahead schedule for the 2028-2029 delivery year.

[8] Moody's downgrades Nautilus Power's rating to B3 from B1, maintains negative outlook. Moody's Investors Service. July 12, 2022.
[9] Moody's downgrades West Deptford Energy Holdings, LLC to B3 from B2; outlook remains negative. Moody's Investors Service. January 13, 2023.
[10] Drop in capacity prices across most of PJM is credit negative for merchant generators. Moody's Investors Service. March 3, 2023.

According to PJM, the auction delay was needed so it could complete the market reforms begun after the December winter storm and wrap up action on the non-performance fines arising out of that event. Both of these issues are discussed in more detail in subsequent sections of this report.

Finally, there is the PJM queue, which is essentially closed as the regional operator looks to revise its approval process and catch up with the massive project backlog that has accumulated in the last few years. This is problematic for new gas development proposals in two regards. First, it slows development efforts, pushing any commercialization dates well into the future while raising costs in the near term. Second, once the process is reopened the buildout is likely to be largely wind and solar projects, which comprise an overwhelming share of the proposals in the PJM development queue.

According to Ken Seiler, PJM's vice president for planning, the system operator has roughly 265,000MW of proposed capacity in its development queue, 95% of which is renewable energy. Of that total, PJM expects to clear 100,000MW of new capacity through the transmission study process by the end of 2025 enabling construction to begin; analysis of a second tranche of 100,000MW is expected to be completed by the end of 2026.[11]

FERC also released a series of policy recommendations in Order 2023 designed to speed project development efforts nationwide. The impact of the July order remains to be seen, but there are a number of common-sense provisions included that should help weed out non-commercially viable projects from queues nationwide and speed the construction of new generation.

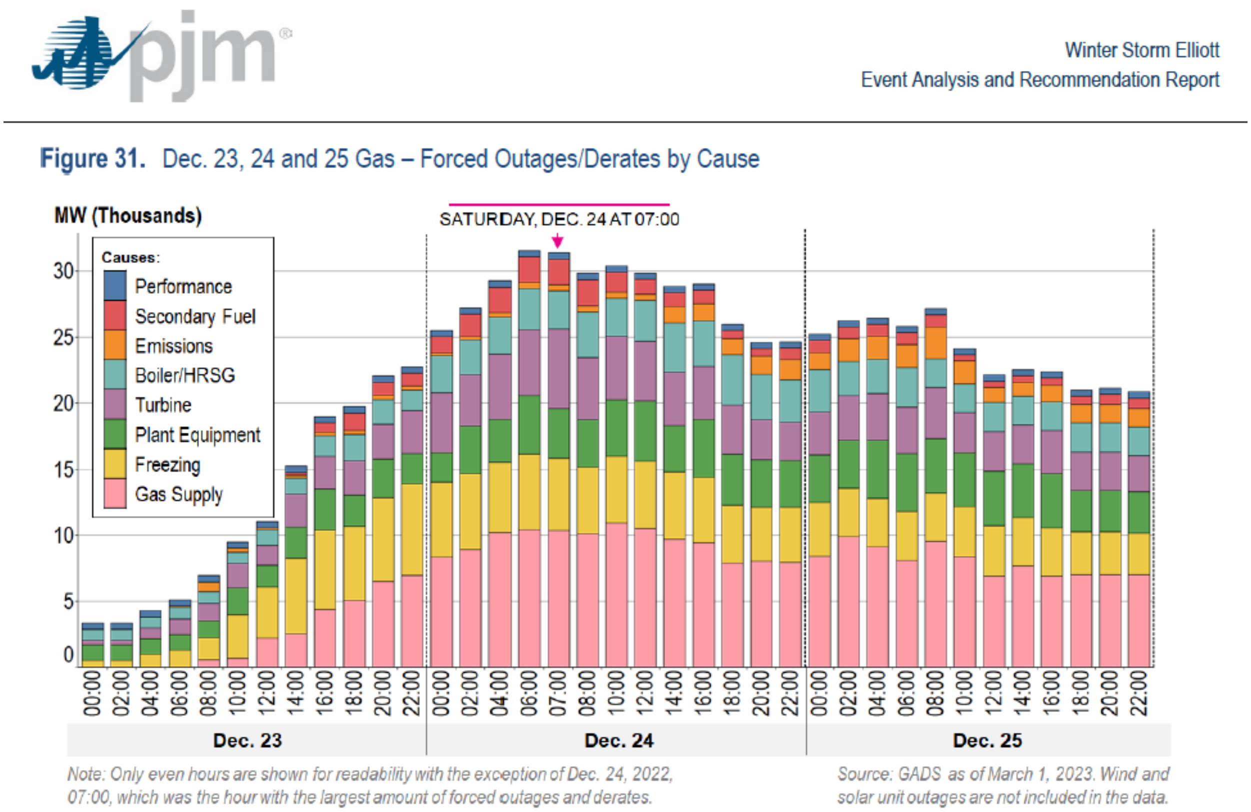
The rising risks for gas developers are highlighted, if unintentionally, in the Energy Information Administration's (EIA) monthly outlook for new plant capacity additions. The EIA data shows just one combined cycle gas plant planned in PJM in the next five years, the 579MW ESC Harrison County plant in West Virginia, which has been on the proposed list for years but has still not started the permitting process. Two other plants, the 1,825MW Guernsey plant in Ohio and the 1,250MW CPV Three Rivers facility in Illinois, began commercial operations earlier this year.

[11] PJM Inside Lines. New Interconnection Process Aims To Ensure Reliability, Enable State Policies. June 30, 2023.

The Costs of Non-Performance

On top of the upheaval caused by the decline in capacity payments, there is the still-unfolding aftermath of the cold weather event (popularly dubbed Winter Storm Elliott), which rolled through PJM last December. At the height of the freeze, PJM generation outages climbed to 46,959MW, almost 25% of the region's total installed capacity.[12] The system's gas plants were hit hardest, with more than 33,404MW going offline unexpectedly during the storm—38.8% of the region's installed gas generation (and, more telling, 71.1% of the total forced outages at the peak).[13]

Figure 3: Winter Storm Elliott Forced Outages/Derates by Cause



Source: PJM.

The outages were caused by a host of interrelated problems, as the graphic above illustrates, but they raise one overriding question for the system: Is the existing carrot-and-stick approach—annual capacity payments to generators to participate and be available when called upon and penalties for non-performance—reliable? A follow-on question is whether the increase in PE and private capital

[12] PJM. Winter Storm Elliott Event Analysis and Recommendation Report. July 17, 2023. p. 49.
[13] *Ibid.*

ownership contributed to the poor performance of the region's fossil fuel generation during the December event.

In the wake of the storm, PJM levied $1.8 billion in penalties for non-performance. The system has not released a complete list of the penalized companies, but it is clear that PE firms were among the hardest hit, as filings at FERC demonstrate.

At this date, it is not certain if the affected entities will be required to pay their fines in full; many of the companies have challenged PJM's actions at FERC and the commission established a settlement process in June to try and resolve the issues without lengthy litigation. Nonetheless, the issue is clearly having a financial impact across the region.

PJM Fines Carlyle Unit for Poor Performance

Carlyle's Nautilus unit, already in financial trouble following Moody's credit downgrade, suffered another blow in the storm's aftermath when PJM fined it for non-performance at its three regional plants. The fine forced Carlyle to inject $88 million into the unit, $58 million in equity and $30 million in capital to enable it to cover the PJM levy.[14]

But that is only part of Carlyle's PJM problems. Another one of its units, Lincoln Power, filed for bankruptcy March 31 after being fined $39 million for power performance problems at its two units in Illinois—the 500MW Elgin facility and the 402MW Rocky Road unit.

As with other projects in PJM, Lincoln Power said in its bankruptcy filing that it has been "experiencing a liquidity crunch caused by the fact that clearing prices from recent capacity auctions held by PJM have decreased significantly and are currently operating at ten-year lows."[15]

Coupled with the fines resulting from Winter Storm Elliott, which the company said are "a multiple of the Lincoln power plants' annual revenues,"[16] bankruptcy became the only tenable option. "As a result of these factors, the debtors' debt load is simply no longer workable."[17]

While not explicitly stated, the bankruptcy filing was likely an attempt to avoid paying the PJM fines, a tactic used frequently by private equity to skirt clean up obligations and reduce retirement and health benefits for companies owned in the coal sector. However, PJM made it clear in repeated filings that it would fight any effort by Carlyle/Lincoln to not pay the storm-related fines. This ultimately prompted Carlyle/Lincoln to propose a settlement to pay the fines through the bankruptcy process.

"Absent the settlement," the companies wrote, "there would be a substantial risk that PJM would attempt to impose the penalties … or an equivalent monetary charge on a potential purchaser of the

[14] Moody's revises Nautilus Power, LLC's outlook to stable from negative; assigns B3 to superpriority extended credit facilities. Moody's Investors Service. April 20, 2023.
[15] Lincoln Power bankruptcy filing. March 31, 2023. p. 18
[16] *Ibid.* p. 19.
[17] *Ibid*. p. 23.

debtors' assets by requiring that the penalties or equivalent monetary charge be paid, or by requiring that the purchaser provide other extraordinary credit enhancements, before the purchaser can be eligible for PJM membership."[18]

In a July 7 filing at FERC, Lincoln Power said the winning bidder for its bankrupt assets was Middle River Power VI and Middle River Power VII. The two entities are owned by Middle River Power, which in turn is a subsidiary of PE firm Avenue Capital. The winning bid for the two power plants was $26.2 million.

PJM Proposes $100 Million Fine for ArcLight's Parkway Unit

In late 2022, Parkway Generation made a $175 million distribution to ArcLight, its private equity owner. Parkway funded the distribution by adding $75 million to its $1 billion term loan and using existing cash. At the time, Moody's said the transaction was credit neutral, given the company's strong performance year to date.[19]

But that was before Winter Storm Elliott.

Parkway owns eight gas-fired power plants in New Jersey and Maryland with a total capacity of 4,800MW. ArcLight bought the plants in Parkway from New Jersey utility PSEG in 2021. They did not perform up to expectations during the winter storm, particularly the Keys Energy Center (761MW) and Sewaren (538MW), two new combined cycle units that both entered commercial service in 2018.

Those performance issues resulted in fines of roughly $100 million according to the company, and prompted Moody's to put Parkway's debt under review for a potential downgrade.[20]

In addition to the PJM fines, Moody's noted that power prices have declined significantly in the past year, which will cut into the company's revenue for energy sales, and capacity prices in the EMAAC region have fallen sharply.

"As a result," the ratings agency wrote, "we expect Parkway's credit metrics in 2023 and 2024 to be significantly lower than our original base case. Our expectation of weak financial performance has also increased refinancing risk at Parkway…."[21]

Whether Parkway will be required to pay the full amount of the performance fines from Elliott is uncertain, but it is clear from PJM's response to the company's FERC filing contesting the fines that the system operator is not interested in a compromise.

[18] Lincoln Power settlement filing. May 3, 2023. p. 5.
[19] Parkway Generation LLC. Moody's Investors Service. Nov. 15, 2022.
[20] Moody's places Parkway Generation's ratings on review for downgrade. Moody's Investors Service. March 17, 2023.
[21] *Ibid.*

"Keys has been a committed capacity resource since [PJM deleted the date as confidential, but the plant began commercial operation in July 2018], and has been well paid by PJM … for all those years to support PJM … resource adequacy at the times of greatest need. But when the PJM region encountered its most acute resource adequacy challenge since the inception of the Capacity Performance construct, Keys was not available at the height of Winter Storm Elliott. And Keys was unavailable because it made the economic choice not to procure fuel and to shut down on the morning of December 23, despite PJM's express request to stay online and run."[22]

The arguments raised by Parkway to defend its decisions at the Keys plant have been used in similar fashion by a group of regional generators who contend that PJM system operators were to blame for the outages and warned that the penalties could push a number of plants into retirement, potentially threatening system reliability in the years ahead as scheduled coal plant retirements take place. The group, which says its members control approximately 27,000MW of PJM capacity, also said the penalties, by pushing generation owners into default, could prompt many of them to walk away from the regional market. "These premature departures from the market threaten to leave PJM without an adequate amount of generation capacity for the remainder of the year and for coming years," the group concluded.[23]

Other generators, those that over-performed and stand to reap bonus payments as a result, have taken the opposite tack and have urged FERC to uphold PJM's penalties.

While the outcome of the FERC-backed settlement process is uncertain at this point, it is unlikely that those discussions will lead to the complete erasure of the PJM fines. Reductions may be negotiated, but they almost certainly will not be cancelled outright. The upshot is additional financial pressure for many of the region's PE-backed fossil fuel plants.

New Capacity Rules Pose Risks for PE Plants

Yet another looming risk for PJM's PE-backed generators is the likelihood of changes in the existing capacity market, particularly regarding winter ratings for gas plants. The current PJM market is structured to meet summer peaks, and operates as if both combined cycle gas plants and combustion turbines are available essentially 100% of the time. The December storm clearly showed that this 100% availability assumption is not accurate in the winter and PJM is now pushing forward with a fast-track process to revise the region's capacity market. It is planning to submit its proposed market changes to FERC in October.

Although the final structure of these reforms remains uncertain, a PJM proposal released in July (see Figure 4 below) gives a good indication of the direction the effort is heading. First, system operators are pushing to implement a two-season market, with capacity bidding for both the summer and

[22] Answer of PJM Interconnection LLC, Docket No. EL23-60-000. May 26, 2023. p. 2.
[23] Group of PJM Generators Complaint

winter. Second, they are proposing to sharply lower the capacity credit for gas plants in the winter, a change that would have major financial implications for the region's PE and private capital operators.

For illustrative purposes, let's return to Heritage Power, which underscored the importance of declining capacity revenues in its decision to file for bankruptcy, noting that they were "the principal source of revenues for its operations."[24]

In its bankruptcy filing, the company said its projected capacity revenues for the current PJM delivery year (June 2023-May 2024) were expected to total $37.5 million. If PJM moves forward with its split season bidding and lowered capacity accreditation levels for gas plants as outlined below, those revenues would fall even further, dropping by anywhere from $4.5-7 million. If $37.5 million was too low for Heritage, what would $30 million in capacity revenues be?

But it is not just Heritage that is at risk. Any downward pressure on winter capacity revenues will heighten the financial problems facing PE and privately owned generators across the region.

While not part of this analysis, the PJM proposal also would significantly raise the winter capacity credit for both on- and offshore wind, another change that could raise financial risks for the region's gas-fired power plants.

Figure 4: PJM Capacity Accreditation Proposal

pjm

Estimated 26/27 Class Average Accreditation Values
(based on "Model 1" to 1993)

	Summer	Winter
Thermals (Overall) *	**95%**	**78%**
Nuclear *	98%	96%
Coal *	89%	86%
Gas CC *	97%	76%
Gas CT *	98%	63%
Existing ELCC Resources		
Onshore Wind	9%	36%
Offshore Wind	17%	68%
Solar Fixed Panel	19%	2%
Solar Tracking Panel	32%	2%

Accreditation for remaining classes forthcoming.
** Does not yet reflect impact of planned & maintenance outages.*

For reference: Current 25/26 BRA ELCC for certain classes

	Class Rating
Onshore Wind	**10%**
Offshore Wind	**21%**
Solar Fixed Panel	**30%**
Solar Tracking Panel	**50%**

Source: PJM.

[24] Heritage Power bankruptcy filing. Op. Cit. p. 24.

Conclusion

There has been a massive shift in the last several years in the risk environment for PE and private-capital-owned gas plants in PJM. The 2010s saw a massive buildout of new capacity with relatively low risk. The situation today is reversed. The buildout has essentially ended, and the risks are accumulating quickly.

First, the high capacity prices that dominated the 2010s have evaporated, with the last three region-wide auction prices averaging less than $40/MW-day, well below the $115/MW-day average in the eight years prior. That constitutes a major risk for existing plant owners and new projects alike, forcing operating projects to make do with less while requiring new developers to convince lenders that their plans are still worth the risk.

The fines from last December's winter storm have simply exacerbated these developments, pushing some existing plants into bankruptcy while forcing others to seek capital infusions from their PE sponsors. On the sidelines, bankers considering a project now know full well that non-performance will be costly, potentially prompting them to raise their financing costs for new gas-fired projects.

Finally, queue reforms look likely, meaning many new renewable energy and battery storage projects should finally enter commercial operation in PJM. This will add yet more risk for existing and proposed gas plants, forcing them to deal both with lower revenues, particularly in the winter with lower capacity accreditation levels and higher wind values, and the likelihood that the addition of new renewable projects will constrain energy prices.

It is a new, much riskier situation for PE and private capital in PJM.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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At IEEFA, Dennis Wamsted focuses on the ongoing transition away from fossil fuels to green generation resources, focusing particularly on the electric power sector.

Institute for Energy Economics and Financial Analysis

Appendix 4

JULY 2021

STRETCHED TO THE BREAKING POINT
RTOs and the Clean Energy Transition

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EXECUTIVE SUMMARY

It has become an article of faith among many in the energy policy world that the Independent System Operator/Regional Transmission Organization model is not just the preferred way to achieve a clean energy grid transition – but the only reasonable way to do so. When confronted with the problems that increasingly bedevil RTOs, these advocates either minimize the threats or suggest a series of modest market tweaks will fix them.

This white paper challenges these orthodoxies. Authored by two experts who have collectively spent decades working with, managing and regulating RTOs, the paper explains why the cracks in the foundations of RTOs are not just cosmetic. It also explores why regulators and the RTOs themselves need to reassess wholesale markets from the ground up as the electricity delivery system transitions to a grid much different from the one of the past.

Given these existential challenges to the RTO model, policy makers should be cautioned against embracing RTOs as the only way to achieve future energy goals, especially in the absence of an identifiable fix to their structural weaknesses.

The white paper acknowledges and accepts the rationale behind the original RTO paradigm, and its historic benefits. It also accepts that the electricity grid will continue to see significant investment in renewable energy – a change fueled by technological advancement, societal demands and public policies. But where it departs from unbridled RTO boosterism is in explaining why many of the underpinnings of the current RTO model are misaligned with public policies that seek to advance grid decarbonization.

Foundational to the challenge facing RTOs is the matter of price formation. Meaningful price signals, as expressed through locational marginal price (LMP), are central to the functioning of RTOs. Prices are the keys to the RTO kingdom. In theory and in practice, prices signal how generation investments should be made, when facilities should retire, and when transmission should be built. They are the primary tool by which grid operators ensure reliability, and they are increasingly important to interconnected distributed resources.

The question becomes: what happens when price is no longer an effective tool for fulfilling the tasks that RTOs were created to complete? If an increasing portion of the grid is characterized by socialized fixed charges and generation that neither sets prices nor responds to price signals, the impact will be profound.

Most renewable advocates argue that RTOs offer the best vehicle to usher in a clean energy transition. They believe RTOs are the only way to build out transmission, ensure customer access to renewables, and achieve deep decarbonization. This paper finds that, in an ironic twist, it may be these very resources that, despite their societal benefits, stretch RTOs past their breaking point. Far from a plea to stop the clean energy transition or the sort of grid that would enable it, the authors argue that regulators and leaders must first candidly confront these tensions. In so doing they should recognize that RTOs – as structured today – may not be the right horse (or at the very least, the only one) to back in the race for clean energy.

INTRODUCTION

Much of the prevailing orthodoxy is that the road to the decarbonized, advanced technology grid of the future goes through a Regional Transmission Organization. If we want to meet carbon targets, expand electrification, and build out the transmission grid then the RTO model offers not just the better, but indeed the only, framework to meet the purpose – or so the argument goes. (1)

What we find perplexing about this singular devotion to the RTO model is how the renewable energy interests shouting loudest for its expansion tend to ignore challenges that are apparent, profound and perhaps even existential to RTOs, at least as we know them today. Equally curious is that many of these challenges are exacerbated by, or even arise directly from, the policy preferences and business models of the renewable interests themselves. And when confronted by these challenges, which might take the form of lethargic interconnection queues offering little cost predictability, or capacity markets that frustrate a state's policy preference to increase renewable resource penetration, the renewable champions for RTOs get angry at the RTOs themselves for not being better or smarter. They're missing the point.

Ask any home improvement aficionado: every tool has its purpose. A hammer is great for driving nails, but drywall screws? You're going to end up with a lot of busted walls and frustration. And so it is with RTOs, struggling to square the circle when it comes to executing on their mission. Inherent in the RTO DNA are principles such as resource neutrality, fuel agnosticism and non-discriminatory economic merit. Selecting a tool built with these attributes to advance the cause of low-carbon emitting resources at the expense of fossil resources seems like an odd choice.

In this white paper, we will look more closely at RTO attributes and how they are likely misaligned with where technologies and public policies are leading the grid. Of critical importance is understanding the role of price and price formation. Central to the RTO model and what distinguishes it from other forms of system operator is its design and use of elaborate market constructs to manage day-to-day system operations and, in some cases, longer term resource adequacy. The engine driving these constructs is price.

It would be nice to think that price is formed simply where supply meets demand; and that the price a buyer pays its seller results from their mutual agreement. The reality for RTOs is that price arises from an immense set of rules that establish an auction and define market clearing algorithms run by complex market settlement software programs to produce a single-clearing price paid to all supply and charged to largely passive demand. In short, the exercise of RTO price formation combines abstract art with impenetrable science. Why is overlaying a centralized market regime to govern a security constrained economic dispatch such a production? The answer lies in recognizing several major constraints endemic to RTO markets, not normally found in well-functioning, organically arising markets. These include: (i) the inability to tolerate shortages, (ii) the non-linear economics and idiosyncratic behavior of supply derived from physical machines with different operating characteristics and performance parameters, (iii) limited participation of active demand and (iv) widespread structural market power concerns.

Okay, so RTO price formation is complex. But these constraints complicating RTO markets are nothing new; they've existed from the outset. How does any of this speak to the question of whether RTOs are good models to lead a clean energy transformation? To answer this question, let's consider the implications on clearing prices resulting from the expanding penetration of renewable resources from three different but interrelated angles: supply (generation and storage), demand and transmission.

1. Letter from former FERC Commissioners to current Commissioners (June 2, 2021), https://documentcloud.adobe.com/link/track?uri=urn%3Aaaid%3Ascds%3AUS%3A5a7f3ba2-5a11-42da-ad75-5c80039e8582#pageNum=1. See also, Renewable Energy Buyers Alliance (REBA), https://rebuyers.org/programs/market-policy-innovations/organized-markets/ ("REBA supports ultimately instituting organized wholesale markets in all regions of the country which are designed and implemented consistent with the principles outlined below, operated by an Independent System Operator/Regional Transmission Organization.").

SUPPLY

Locational clearing prices are the defining feature of the RTOs' energy markets, certain of its ancillary service markets, and in some regions, its centralized capacity markets. To those of us steeped in RTO markets, we take as a given that these markets are single-clearing price auctions and forget that this design is rather unusual, and unlike most other commercial markets, including financial and commodity markets, where price is set once a buyer "lifts" an offer directly from a seller. Indeed, this is how electricity is bought and sold in bilateral market regions around the country. There is no auction, no central counterparty, no passive demand established by forecast and no single-clearing price. But in RTOs the single-clearing price auction is the default. One might go so far as to say, it's the only form of competitive procurement RTOs consider. If something must be bought and sold in a competitive manner in the RTO, (2) then, by golly, let's run an auction.

There is sound reason to back the use of a single-clearing price auction in organized wholesale markets. The reasoning is well established and need not be repeated here. However, it rests on an important assumption; namely, that we can treat electricity as a commodity. (3) A definitional element of a "commodity" is that one unit of the product is fungible to the next. The assumption that one kilowatt hour is fungible to the next has proven workably correct over the years in RTOs. (4)

Of course, electricity (at least in a form useable to power homes and businesses) doesn't simply exist in nature – it is created by machines. Created, in fact, by a variety of different machines, some that harness and directly convert kinetic energy found in nature, some that convert solar radiation through photovoltaic technology, some that burn fuels or split atoms to create thermal energy which in turn creates mechanical energy in an electromagnetic field, and some that create an electric current through an electro-chemical reaction or through electrolysis. And these are still very general classifications, underlying each is a broad range of specific generating technologies, from flywheels to back-up diesel generators; dams to hydrogen fuel cells, nuclear powered pressurized water reactors to windmills, trash burning generators to mine-mouth lignite plants and the list goes on.

The point is, electricity comes into being from a much broader array of methods and technologies than other commodities, such as copper, corn or natural gas. (5) But do these differences matter when assuming commodity market-type fungibility in designing RTO electricity markets?

While the fungibility assumption has been workable to date, it's hardly been perfect. Assuming fungibility while respecting real world characterizations defining different generating plants and generating technologies has required "compensating fixes" unique to RTO markets. These include rules to govern how generators offer and how they are paid, consistent with their physical characteristics such as the unit's minimum run time, start-up times and commitment level (described in PJM as the unit's "parameter limited schedules"). In some cases, marginal resources and the supposedly fungible electricity they generate are not eligible to set the clearing price, giving rise to the "compensating fix" known as uplift costs. (6)

2. By "competitive" we mean to exclude RTO products whose price is set by regulation, such as black start service, reactive power and transmission service.
3. Another dimension to this question is whether, as a matter of public policy or legally (for example, under the Bankruptcy Code), electricity should be treated as a "public service" or a "commodity." These debates fall beyond the scope of this paper.
4. Generators injecting onto and load consuming off the grid is often analogized to the irrigating and withdrawing of water from a pool – a conceptualization which reinforces the notion of electricity as a fungible commodity.
5. RTOs administer their centralized auction markets for the purpose of meeting a delicate physical goal which is to keep the grid secure, in balance and functioning to deliver electricity to ultimate consumers in real time and in all hours of the day and night across all four seasons. The relationship between the price outcome in the RTO market and meeting the physical requirements attendant to delivering electricity to the ultimate customer is much more immediate than the financial derivative or secondary markets in which other commodities are bought and sold.
6. Uplift costs are widespread and result from various "out of market" actions taken by the RTO to maintain reliability, such out-of-merit order dispatch and redispatch with payment of lost opportunity costs. *See generally*, Federal Energy Regulatory Commission, *Staff Analysis of Uplift in RTO/ISO Markets* (August 2014), https://cms.ferc.gov/sites/default/files/2020-05/08-13-14-uplift_2.pdf.

Holding to the fungibility assumption in the case of single-clearing priced capacity markets has proven more strained. (7) If a purpose of a capacity market is to buy iron in the ground, treating one MW of wind capacity as fungible with a MW of natural gas capacity means we're ignoring some pretty different looking, and performing, irons in the ground. (8)

Notwithstanding these challenges, single clearing price locational marginal prices for energy, co-optimized ancillary services and energy derivative products (FTRs) have on balance worked well – to date. (9) An important design predicate that justified the rough fungibility of electrons in the RTO market, which in turn enabled the operation of single-clearing price auctions (albeit with "compensating fixes") was the expectation that generating electrons came with a marginal cost. The "M" in LMP.

The fact is, some resources – and it's those resources whose participation has seen a dramatic increase – have low or no marginal costs as that term is defined by RTO rules, economists, market monitors and regulators. This fact, in our opinion, is the straw that breaks the fungibility camel's back, and poses an existential challenge to the continuing operation of single-clearing priced auction markets for energy and related services in RTOs. We don't believe it will be possible going forward to ignore how the kilowatt hour was generated and simply conduct an auction among all kilowatt hours however derived to set a single-clearing, locational marginal price to pay the various types of generators injecting that electricity. (10)

A difficult fact to accept is that many suppliers in RTO auction markets do not contribute to formation of the energy clearing price. Many are price takers because they are inflexible base load plants, in particular nuclear. Many are price takers because they have next to no marginal operating costs, in particular solar and wind. Finally, many have quite obvious marginal costs, but due to the inflexibility of their operating parameters (say a minimum commitment block) these cost-based offers are ineligible to set the clearing price. Taking this liquidity off the table means that LMP outcomes are not as competitive as many might assume. But more to the point of this paper, it means that in order for LMP to come close to representing the value of the wholesale electricity supplied, a flexible resource with meaningful operating costs must set the single-clearing LMP paid to all suppliers. This need is met in RTO markets by fossil units, typically natural gas simple and combined cycle generation. Stated more directly, in order for a renewable resource to obtain positive revenue from selling its energy in an RTO market, it must rely on a carbon emitting fossil resource to set a positive LMP.

The economics of an investment in renewable generation turn only to a degree on the energy, capacity and ancillary service revenues realized from the RTO market. Other revenue streams, such as renewable energy certificates, production or investment tax credits and bilateral contracts from load serving utilities pursuant to state programs or commercial and industrial customers are important. In fact, their importance is likely to increase as RTO market revenues remain depressed with greater numbers of low marginal cost resources dominating the supply stack in many hours. The choice facing policymakers is limited. As market revenues degrade, either we must embrace more fully these kinds of out-of-market revenue sources or instead accept

7. A recent post from the Sustainable FERC Project indirectly questions the dubious fungibility assumption underlying capacity markets when it analogizes renewable and fossil generation to heirloom and corporate farm tomatoes respectively. Tom Rutigliano, *Fix The MOPR Problem With A Dose of Humility*, Sustainable FERC (Apr. 28, 2021), https://sustainableferc.org/fix-the-mopr-problem-with-a-dose-of-humility/.
8. The "compensating fixes" here include rule frameworks to measure effective load carrying capability or other rules discounting more bluntly the MW value of different technologies. Though empirically driven, that hardly saves them from controversy.
9. We are less convinced when talking capacity markets. *See also*, Jay Morrison, *Wholesale Power: Fungible Commodity or Differentiable Product?* Public Utilities Fortnightly Magazine (Nov. 1, 2018)("It's time for the Commission to finally accept the political, economic, and operational reality that wholesale power is not a fungible commodity.")
10. The question of how to form viable energy prices in RTO markets as zero-marginal cost generation become a more meaningful component of the supply stack has been identified and discussed for years now. *See, e.g.,* Paul L. Joskow, *Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience*, at 37, (M.I.T. Ctr. for Energy & Envtl. Policy Research, Dec. 18, 2018), https://economics.mit.edu/files/16650. We're not aware whether those pondering solutions to the problem have questioned the fungibility predicate underpinning LMP price formation and whether treating a wind farm (the heirloom tomato described in footnote 7, *supra*) as comparable to a coal plant so upends this assumption as to dash real hope the RTO can heal its markets through relatively simple fixes to the single-clearing price auction rules.

heretofore highly unpopular RTO administrative markets (like capacity markets) or outright regulatory proxies, such as RTO administered reliability must run (RMR) contracts. (11) In either case, wither the single clearing LMP market as a construct to induce and sustain generation, renewable or otherwise.

Put another way, RTOs need to come to terms with the reality that we may be rapidly moving towards a post-marginal price world. And as we will see throughout this paper, that new paradigm will have enormous implications for the viability of the RTO model. So, it's bemusing to observe many in the renewable industry champion RTO markets, given they themselves likely represent the seed that will destroy them, at least in their single-clearing price auction form. As the City of Venice might say to the summer tourist: "we love you, but you're absolutely killing us!" (12)

Prices carry information. To investors they signal when and where to invest. To consumers they signal how much to consume. To suppliers they signal when and how much to supply. As we've discussed, as RTO prices degrade and the quality of information is compromised, interventions become necessary to correct inaccurate information and misdirecting signals. But losing an effective LMP market presents not only an economic efficiency challenge, but also a system operations challenge to the RTO. Price is probably the RTO's most important tool to control the system and maintain balance and security. At one time, those warning against RTO geographic expansion predicted that a single dispatch across a large region would be unmanageable and unreliable. These skeptics were proven wrong because they didn't appreciate that price would do the heavy lifting in unit commitment and ramping that manual operator direction had done previously.

Degrading prices that no longer communicate the right information as far as what the system needs and when it needs it to maintain reliability will require their own kind of corrective intervention. And anyone hopeful for a system where supply is more decentralized with many smaller, distributed resources sitting closer to customers should be a vigorous advocate for getting prices right. The point is simply that in RTOs reliability is highly dependent on price integrity.

But the problem is more profound than embarking on "compensating fixes" or interventions to neutralize the static and restore the price signal. Even if price integrity is restored, what does it matter when an increasing portion of the supply stack doesn't actually respond to price? When you appreciate the RTO administers markets only because it believes its markets deliver reliable operations most efficiently, the conundrum presented in having a supply stack that effectively thumbs its nose at price is evident. Non-dispatchable intermittent resources will inject energy when it's sunny or windy without regard to the RTO's price signal. Zero or even negative prices, something seen occasionally in the market for old televisions and undistinguished brands of upright pianos, but not in markets for other fungible commodities, is a sign something is wrong and unhealthy with the state of RTO electricity markets.

Perhaps breakthroughs in storage technology, or a very different paradigm for participation of demand in the market, might save the RTO's single-clearing price auctions. But for the moment, let's recognize that the RTO market model was predicated on the assumption that generators:

11. A third option might be to "fix" LMP by changing price formation rules. In 2017, PJM launched an effort to question long-held price formation assumptions in light of the changing resource mix. The idea of "Integer Relaxation for Electricity Market Clearing," was floated and sunk promptly upon leaving the dock. Aside from attracting substantial controversy, some based on well-founded concerns such as controlling costs and the exercise of market power, this kind of approach wades further into the "compensating fix" labyrinth described above. A summary of the complex proposal, prepared by the Harvard Energy Policy Group and PJM, can be found here: https://hepg.hks.harvard.edu/files/hepg/files/hepg_chao_jan_2018.pdf?m=1523367435.

12. The RTO model holds an obvious appeal to generation developers of all types. RTO's provide a guaranteed buyer for the output of the developer's plant – no questions asked. Of course, unbridled merchant investment is disciplined by economics that start by assessing how competitive a new plant will be in light of its fixed and anticipated operating costs. This discipline begins to break down when investment is supported by significant revenue streams outside the RTO market, and where the plant has no operating costs to speak of. Under these circumstances, the RTO as a buyer finds itself in a kind of "take or pay" posture – it essentially must absorb all energy output offered by the zero-marginal cost generator, even if it drives LMP to zero or below. It's then left with the job of finding other means to bring in or retain supply resources that provide the RTO the full complement of operational attributes it needs to keep the system reliable.

1. While different, had sufficiently similar operational characteristics that we could regard their electricity as fungible and impose a single clearing price auction-based market design that replicated outcomes found in markets for other fungible commodities;
2. Had real operating costs, in particular fuel costs, that would set a sufficient LMP, when considering all hours in the year, to compensate economic resources for the services they provided to meet demand; and
3. Would respond to LMP signals in a manner consistent with system operator needs and thus enable the market to deliver system reliability.

In considering whether the RTO market model is indeed our best framework to advance the decarbonization agenda, we must ask whether these assumptions continue to hold. We don't think they do. Moreover, we fear these assumptions are so profoundly integral to the RTO market model that either the market must be overhauled or alternate regulatory models given greater consideration.

But before making this policy call, note we have thus far addressed only the present and likely future implications to *supply* resulting from the degradation of price in recent years under the RTO market model.

Let's turn to demand.

DEMAND

Since its inception, delivering reliable electricity has required the operator to accept load, more or less as it comes and goes, and to control a supply stack, that while lumpy, responded to dispatch and ramping instruction. For an RTO, the tool of choice to commit and control generation is price.

In an RTO, for price to do this job, price must be "correct." In practice, "correct" almost always means: does the price create incentives (or disincentives) aligned with desired reliability outcomes? RTOs, their stakeholders and regulators have become accustomed to a never-ending refinement of market rules chasing the goal of incentive compatibility. (13) So it's not surprising to expect RTOs to respond to the novel operational challenges presented by intermittent generation by tinkering further with the rules governing price formation. But this time, the problem is different because it poses a challenge wholly unanticipated by the foundational design of the market: how to control a supply stack that is impervious to the price signal – regardless of how "correct" the price might be?

Short of revolutionary advances to the likes of storage or fuel cell technology - in other words, living with a portfolio increasingly comprised of supply that "is what it is" - then we need to get serious about controlling demand. In fact, a lot of recent literature extolls the promise of demand response as a tool to manage the operational challenge of intermittent renewables and give operators necessary control over the system. But perhaps nothing illustrates how far we have to go in this regard than images this past February of well-lit pandemic-vacated downtown skylines in Austin, Houston and Dallas taken by people gathered around open fires trying to stay warm in suburban backyards.

The RTO model offers promise when it comes to controlling demand because its markets should produce real time price signals that can communicate with smart technologies. When incentivized by smart regulation, this should result in consumers curtailing or deferring consumption to meet reliability objectives. Of course, this sort of direct retail "price responsive demand" has, by and large, never lived up to its promise. Why? In part because of unsupportive regulatory paradigms and an understandable reservation about exposing consumers to volatile time of use prices for an essential service. (14) But also because asking price to change consumptive patterns

13. The ideal would be the complex workings of a Swiss watch telling reliable time for years with just a periodic cleaning of the gears. The reality is closer to a 1960's Italian sports car that might run beautifully, provided it's not in the shop.
14. Indeed, one of the public policy casualties of the February Texas electricity crisis was the business model of those energy retailers (most famously, "Griddy") which pierced the veil between wholesale and retail prices, by exposing consumers directly to wholesale market prices. In the wake of the disaster, the Texas Legislature banned such rate plans from the retail marketplace. See Reese Oxner, *Griddy Energy customers may be off the hook for exorbitant energy bills after company files bankruptcy*, Tex. Trib. (Mar. 16, 2021), https://www.texastribune.org/2021/03/16/griddy-bankruptcy-electricity-bills/.

means changing how and when goods and services are produced and delivered, in short, changing how people live their lives. (15)

It's a tall order. That sort of consumer inconvenience may have been acceptable in the plain old telephone service days, when "Ma Bell" made it worth waiting until nights and weekends to call distant family members. But when it comes to electricity, the thing that makes modern life possible, it is a challenge on an entirely different level. One of us penned a short piece in the early months of the 2020 pandemic observing the flattening peaks in PJM as people woke up at different times, worked from home and as office buildings and the like cut back consumption. (16) These observed changes in usage patterns, and the promise they might continue to a degree after the pandemic subsided, suggested our public health crisis could have lasting impacts "affecting how society lives and works (which) may change load behaviors in a way that decades of price incentives and regulatory programs have largely failed to do." The point is, if it takes a global pandemic to see meaningful changes in how electricity is consumed, what chance does price have to drive the same behavioral change?

But let's put aside the debate as to the degree to which consumers are price elastic and whether price responsive demand can ever serve as a sufficiently powerful tool for the operator to control the system. What is axiomatic is that when that operator is an RTO, any hope to change consumption patterns starts with a viable LMP. In discussing supply, we've already described the problems getting a viable LMP with zero-marginal cost generation.

On the face of things, this problem (degraded energy prices) would seem to work in favor of encouraging load to consume more at the "right" times and less at the "wrong" times. As with many things in the RTO world, the situation is more complex. Even today, in places where the consumer is, indirectly and to a limited extent, exposed to the RTO's real time energy price, the signal is so muted that only the most hopeful stargazers can imagine a world where LMP provides RTOs an operative tool to maintain system balance by moving retail load. First, in most instances, consumers are not exposed to the dynamic (variable) nature of LMP. Second, load is usually settled at a zonal average price and not a nodal LMP. Third, and most important to this discussion, the LMP signal is being overwhelmed by other fixed, non-bypassable charges on the retail bill. And this signal-to-noise ratio is trending in the wrong direction with non-bypassable retail charges multiplying as a consequence of increasing renewable penetration.

Let's explore further the problem of non-bypassable charges. One set of ideas offered to solve the problem, discussed earlier, of how to form LMP without the "M" is to have the RTO create a suite of new product offerings to compensate suppliers more precisely for providing the flexibility, fast start ramping, inertia, stability, etc. necessary to maintain system balance in a high renewable penetration world. Pricing these "reliability services," at least if they are to be co-optimized with those same energy market LMPs still impacted by zero-marginal cost generators, sounds either futile or shockingly expensive in a single clearing price world. But in either case, these new services will add even more complexity to a pricing regime that hardly needs more intricacy.

When considering the conundrum facing RTOs in paying for necessary reliability services, the simpler perspective envisions fossil units "backing up" renewables. This perspective suggests a pricing approach that pays a reservation fee (like RTO compensation for capacity or black start services) or a separate performance fee, not tied to, or co-optimized with, energy market prices (like RTO compensation for reactive services). In either case, by the time these charges reach the retail bill, they almost certainly will appear as fixed, non-bypassable charges.

15. Some changes have minor impacts like shifting fixed interval cycling of certain motors (e.g., pool pumps) or modifying thermostat driven cycling of air conditioners. More meaningful changes involve rescheduling production lines from day to night time, for instance. And some consumption, think street lighting, is just unable to shift regardless of the price signal.
16. *See* Vincent Duane, *Stakeholder Soapbox: 'In These Uncertain Times…'*, RTO Insider (May 18, 2020), https://www.rtoinsider.com/articles/18307-stakeholder-soapbox-in-these-uncertain-times-.

Other fixed, unavoidable charges on the retail bill are transmission and distribution costs. The interconnection of distributed renewable resources at distribution level voltages quite often presents operational issues, like stability concerns, requiring reinforcement of the delivery system. More impactful, is that the locationally constrained nature of wind and solar demands massive reinforcement of the grid or new high-voltage transmission build. We'll get further into the topic of transmission below, but the point to make here is that the distribution and transmission upgrades needed to bring on-line renewables at scale to address current carbon targets will result in dramatic increases to the unavoidable delivery component of the retail customer's bill.

Finally, programs preferred by policymakers to support renewable resources, like solar renewable energy credits or zero-emission energy credits for nuclear, have not been allocated as a tax to the public, but again as a non-bypassable charge to retail electricity consumers. These charges sit alongside the modified pass through to the retail consumer of the RTO's LMP, diluting the signal that LMP might otherwise promise to modify consumption behavior.

We note in passing the likely harm to competitive retail electricity programs that results from expanding the non-contestable components of the retail bill (reliability services, transmission/distribution and support programs for clean resources). (17) But our focus is on the RTO confronting a supply stack that is largely uncontrollable, and whether RTO price signals can be expected to control demand to maintain system balance – even assuming existing regulatory impediments are resolved and customer enthusiasm for uptake increases.

Low wholesale prices (even artificially low negative LMPs) resulting from zero-marginal cost generation *should* provide a basis to build a price responsive demand regime that drives consumption away from low renewable output/high price hours of the day (and night). But as the saying goes, "there is no free lunch." A sober assessment must recognize that in order to affect a customer's decision to consume, this otherwise low-price signal must overcome the noise coming from companion non-bypassable charges that a customer typically incurs without regard to its energy consumption in a given hour. As noted, many of these charges arise in the first place to support or facilitate entry of the clean resource.

All this said, we still believe demand response is appealing in a world of increasing renewable penetration as a tool to maintain balance. Shifting consumption to periods of intense renewable generation and away from periods where fossil resources must be dispatched to balance intermittency has obvious operational benefit. It seems, however, that this will be accomplished by programs that offer a more obvious incentive to customers. (18) Such programs do not depend on, and in fact may be complicated by, RTOs and their wholesale energy pricing regimes. And this should give further pause to those claiming the RTO market model is the best or only way to accelerate a carbon free grid.

TRANSMISSION

We've referenced the widespread call for massive reinforcement and expansion of the transmission grid to accelerate a renewable transformation. The companion call is that we depart from a participant (generation developer) funding of this build out, to a socialized allocation of costs, recognizing the broad set of beneficiaries

17. Similarly, these phenomena will have deleterious effects on the much-touted rollout of distributed energy resources (DERS) and energy storage. For if energy prices throughout the wholesale markets are materially unmeaningful, then it will have an impact on distributed and storage resources as well. This is true both in terms of an investment signal to those who might install them – but also in relation to how the they will interact with the reliability operations of RTOs, all of which depend on getting prices right.
18. *See, e.g.*, Laura Mørch Andersen et al., *Paying consumers to increase their consumption can reduce the cost of integrating wind and solar electricity production into the grid*, VOX EU CEPR(April 26 2019) https://voxeu.org/article/reducing-cost-electricity-supply-paying-customers-increase-consumption.

associated with a carbon free grid. (19)

While this advocacy is persuasive, and we don't argue with the need for extensive transmission network expansion, how comfortably does it sit alongside the proposition that the RTO market model offers the best - or only - path to rapidly decarbonize the grid? Again, there are certain foundational elements of RTO design that seemingly are being swept under the rug.

The starting point is to understand that transmission under the RTO model was not intended to enable generation, at least not in the sense being discussed today. In disaggregating the natural monopoly and exposing generation and (in some cases) retail load to competition, transmission was left apart as a regulated "essential facility." The line drawn between competitive generation and regulated transmission was a bright one. In an RTO model, it was understood that transmission competed with generation in that a reliability criteria violation identified by the RTO's long-range transmission plan might anticipate a network upgrade, unless the market intervened to induce new generation whose entry relieved the constraint thereby cancelling the planned transmission upgrade. The advent of transmission planning for economic and/or public policy purposes pitted generation versus transmissions solutions against each other even more explicitly. (20)

We've talked several times about the "M" in LMP; let's turn to the "L." The genius of locational pricing is that it transparently reflects in energy prices the cost of congestion which can be compared to the cost of a network upgrade which increases transfer capability to relieve that congestion. Locational price separation additionally signals where generation is needed and where it is not. By its very design, locational pricing in concert with the participant funding of generation interconnection works to limit the overbuild or "gold-plating" of the transmission system by (i) pricing congestion transparently and efficiently and (ii) signaling where on the system generation is most valuable. A substantial infrastructure has evolved both in RTOs and in secondary markets to reflect this regime. (21)

Having the RTO centrally plan transmission to identify geographic areas where wind and solar resources can be harvested and then developing socialized transmission infrastructure to deliver low-cost renewable resources to load centers has a pragmatic appeal given the scale of decarbonization being envisioned. But let's not kid ourselves. This approach to planning, developing and paying for transmission upends a lot of the design purpose of LMP and the infrastructure that has developed to execute on this design purpose.

Not to mention, it places one competitor (the zero-emission generator) at a clear advantage compared to other competitors (the dispatchable generators) - the latter having to account for interconnection and network upgrade costs as part of its investment decision. Again, favoring carbon free generation in this respect might be the desired public policy, but aside from straining the non-discriminatory stipulation of RTO markets, it removes the locational advantage for generation proximate to load that would otherwise have been revealed in LMP.

Perhaps the most striking real-world example of the implications of these policies is the Texas CREZ model of transmission development. (22) The policy experiment was certainly effective at getting transmission built and,

19. A good example advocating both points comprehensively is a report commissioned by the American Council on Renewable Energy (ACORE), in coordination with the American Clean Power Association and the Solar Energy Industries Association. Julie Lieberman Concentric Energy Advisors, HOW TRANSMISSION PLANNING & COST ALLOCATION PROCESSES ARE INHIBITING WIND & SOLAR DEVELOPMENT IN SPP, MISO, & PJM (March 2021) https://www.eenews.net/assets/2021/03/29/document_ew_01.pdf. See also Federal Energy Regulatory Commission, Notice of Technical Conference, Docket No. AD21-12-000 (Mar. 2, 2021), https://www.ferc.gov/sites/default/files/2021-03/AD21-12-000.pdf.
20. A good overview of RTO planning, including descriptions of economic or market efficiency planning introduced beginning in 2006, can be found in Joseph H. Eto and Giulia Gallo Regional Transmission Planning: A review of practices following FERC Order Nos. 890 and 1000 Lawrence Berkeley National Laboratory (November 2017) https://certs.lbl.gov/sites/default/files/lbnl-2001079-appendices.pdf
21. It starts with tradeable transmission rights and includes markets to hedge the basis risk between generation and load, banks offering structured risk management products to support asset investment, speculators offering liquidity and centralized trading and clearing environments (such as Nodal Exchange).
22. *See Transmission & CREZ*, Powering Texas, https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf.

in so doing, dramatically jump-started renewable generation development in Texas. But any suggestion that market forces within the RTO (in this case, ERCOT) were primarily responsible for Texas' renewable development strains credibility. Taking the biggest expense associated with the development of geographically distant intermittent generation resources and uplifting the cost recovery across an RTO footprint is the antithesis of a market. That the resources have no fuel costs and therefore further depress LMPs only compounds the impact.

While not necessarily exclusive to the RTO model, we agree the geographic expanse of some RTOs (not all) can offer compelling scale and portfolio benefits to help manage the variable nature of solar and wind resources. Our goal is not to push back on those seeking to extend this scale by promoting a plan for substantial network expansion and upgrade whose costs are broadly reflected. Rather, it is simply to point out how incompatible that plan is with the logic and intended workings of LMP.

CONCLUSION

There is a widespread orthodoxy among those seeking rapid decarbonization of the grid, consisting of the following tenets:

1. Supporting renewable entry through programs, tax credits, and out-of-market contracts that value renewable's positive environmental externalities, while affording renewables preferred access to the grid;
2. Seeking ways to control demand as the supply stack becomes less controllable; and
3. Building out transmission to optimize renewable generation and manage its variability.

Where we stumble boarding the bus is with the next plank in the platform:

4. Items 1, 2 and 3 are best accomplished – perhaps exclusively – through RTOs.

By offering a single dispatch over a broad geographic area and broad regional planning, we see the appeal of RTOs to those seeking to advance decarbonization. The RTO is also extoled because it offers universal entry into its markets and a captive buyer to all suppliers. Here is where we say, "now wait a minute."

The engine driving RTO markets is the single-clearing locational marginal price. For the reasons discussed here, we harbor reservation about how this model – one which rests on assumptions of fungibility, non-discrimination and resource neutrality - can continue to work both operationally and economically as more wind and solar interconnect, particularly under the terms stated in item 1 above.

Does this mean RTOs can't serve as a vehicle to advance decarbonization? No. But we are inclined to think RTO wholesale electricity markets, which are a defining feature, will have to be re-thought from the ground up. This isn't going to come easily or quickly – particularly considering structural and governance features of the RTO which we intend to explore in a subsequent paper.

In the meantime, it strikes us as a bad, perhaps even dangerous idea, to rule out all other regimes (both existing and potential new or hybrid models) to instead insist on pursuing all efforts to decarbonize the electricity grid through a universally imposed RTO model. In the final analysis, we are intrigued by RTOs and their markets, and we have spent considerable time over the years working to improve them. However, we are simply unwilling to put all our climate eggs into that one basket. Too many industry, technology and public policy trends currently in-motion are working at cross-purposes to several central organizing principles of the RTO itself. An honest assessment of the compatibility of the RTO model to these policy trends should incorporate that consideration, and caution against those seeking to press RTOs as the one and only solution to decarbonizing the power grid.

Appendix 5

WILKINSON BARKER KNAUER, LLP

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RETHINKING AND RESTYLING AN OLD IDEA

A NEW MODEL OF TRANSCO TO PLAN AND OPERATE A CHANGING GRID

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I. INTRODUCTION

This is the final in a three-paper series examining how well RTOs can be expected to handle the ongoing grid transformation in this country. This transformation seeks to:

- Maintain current reliability at reasonable costs to electricity consumers;
- Expand the grid to meet new electrification needs; and
- Reduce dramatically carbon emissions.

Our writings have voiced skepticism that the RTO, as currently constituted, offers the best model to realize our grid transformation objectives. Our prior two installments concluded, respectively that:

- The foundations of the RTO (its reason for being and the design of its markets and planning) are inconsistent in critical ways with these objectives; and
- Multi-state RTO governance is likely too weak to execute on these objectives due to competing and parochial policy-setting and insufficient executive authority vested in the RTO to navigate competing policy directives.

Plainly, this casts us as skunks at the RTO garden party, spilling our drinks on the well-dressed technology company, big box store and renewable developer guests there toasting RTOs as champions of transformation.

And while our posture in appraising RTO challenges bears an uncomfortably close resemblance to that of Statler and Waldorf,[1] upon closer inspection, it is not unique or exceptional. Indeed, RTOs face schizophrenic commentary from many participants as well as from regulators and policymakers. While many tout RTOs as the path to grid transformation, these same voices actively and very publicly criticize actual operations, planning, market design and governance of their own particular RTO. Periodically, the volume of rebuke is amplified to the point of threats to leave the RTO (e.g., in PJM), calls to remake the RTO from whole cloth (e.g., in ISO-NE) and actions to disengage from or limit RTO initiatives.[2]

What do we deduce from this love/hate relationship?

RTOs were, in part, created to bring competition to the supply (generation) side of the business in response to expensive asset investments put to ratepayers under cost-of-service regulation. This is especially true in regions like the Northeast, where utilities were unbundled. Here, "competition" meant liberating ratepayers from underwriting the costs and risks of investment in generation and instead placing these costs and risk on those better positioned to manage them – merchant investors. In other regions of the country, particularly the Midwest and Plains states, a primary driver for RTOs was a desire to achieve greater efficiencies through scale, reserve sharing and joint dispatch of utility owned generation.

Indeed, RTOs face schizophrenic commentary from many participants as well as from regulators and policymakers. While many tout RTOs as the path to grid transformation, these same voices actively and very publicly criticize actual operations, planning, market design and governance of their own particular RTO.

Yet today the entry of wind, solar and storage resources to displace fossil generation is supported by the ratepayer, and to a degree, her close cousin, the taxpayer. These are not merchant investments. This is true in both RTO and non-RTO markets. And if the public policy priority is reducing GHG emissions, that may not be a bad thing. But let's be clear, it's also not a result of the competitive forces and the market signals RTOs were designed to harness. In fact, as we've argued in our first paper, the economics behind the design of RTO markets can actually work in conflict with the forces effecting grid transformation.[3]

1."Statler and Waldorf are a pair of Muppet characters best known for their cantankerous opinions and shared penchant for heckling. The two elderly men first appeared in *The Muppet Show* in 1975, where they consistently jeered the entirety of the cast and their performances from their balcony seats." *Wikipedia*, https://en.wikipedia.org/wiki/Statler_and_Waldorf

2. Examples include MISO's current proposal to essentially separate its RTO into a north and south region for transmission planning and cost allocation purposes and Dominion's recent decision to move its Virginia and North Carolina customers out of the PJM capacity market.

3. Our first paper labors the point that economically correct prices are essential by design to reliable and efficient RTO operations. When marginal prices are formed in a single-clearing price auction that assumes all supply is fungible, incorrect prices will result if zero-marginal cost, price-taking suppliers supported by out of market programs are permitted to contribute to the price formation exercise.

Then what does explain statistics showing impressive carbon free resource penetration in RTOs and tremendous potential growth in this penetration as seen in some RTO backlogged interconnection queues? The answer largely lies in controlling for other drivers:

(i) states that pursue aggressive programs to support renewable penetration;
(ii) the geography or natural conditions to harness solar and wind energy; and
(iii) the prevailing cost/price of wholesale energy regionally.

A high-cost state, with wide open spaces offering strong irradiance or reliable winds, and a political/corporate will to push towards a net zero carbon path will explain a high or growing penetration of renewables, more so than whether that state happens to be in an RTO.[4]

The RTO model has long been seductive as an ideal or theoretical construct. In practice, it has proven messy, complex and unstable despite its success realizing operational efficiencies by harnessing forces of geographic scale and competition. We won't dwell on this point, except to say it may explain why we have spent two decades and counting continuously "tinkering"[5] with, adding to and ultimately obfuscating the business and scope of RTOs as we seek to align them more closely to theoretical vision and promise.

Outside academic and wholesale market designer circles, we don't sense that today's campaign for RTOs as agents of grid transformation is driven by faith that we'll get electricity prices "right" if we just continue working to adjust market design to align with the devilish operational physics arising from a changing grid. The big technology companies and renewable developers have shown little enthusiasm about ideal RTO market design and reforming wholesale prices to signal behavior consistent with reliable operations. Instead, their advocacy for the RTO is the hope it will break down state regulated utility fiefdoms to bring about deeply decarbonized, multi-state centralized regional grid operation. It promises this outcome, so the argument goes, by offering new entrants and disruptive technologies, access to RTO market revenues and a more accessible physical interconnection to the grid, including having the RTO commission new transmission as needed to support such access. This is the new RTO ideal taking hold.

...we don't sense that today's campaign for RTOs as agents of grid transformation is driven by faith that we'll get electricity prices "right"

And it's the ideal we've chosen to focus on here. RTO proponents like the access it offers, (access to interconnect and participate in an open market) and the regional efficiencies and broader geographic operations that RTOs can accomplish. It is no surprise then that several of these companies are now RTO stakeholders. So, what we will do here is:

- Examine how renewables access the RTO grid and how undisciplined access in RTO markets is causing an opaque and unfair shifting of costs among participants and consumers in those RTOs.
- Suggest that disciplined access and regional efficiencies through coordinated planning and operations over a broad geography can be realized through private ownership, TRANSCO and TRANSCO-type structures.

4. *See, e.g.*, Joskow, P., *Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience*, MIT CEEOR, Working Paper Series, p.36 (January 2019)(discussing subsidies supporting solar and wind entry in contrast with with dispatchable (generally fossil) resources relying on RTO energy, ancillary service and occasionally, capacity market revenue streams) https://economics.mit.edu/files/16650

5. The terminology is borrowed from Professor Joskow, *id*.

II. ACCESS TO THE GRID AND MARKET

RTO markets to date have passed judgment on clean energy technologies, and the resounding outcome is that, lacking government support and other revenue from outside the market, they are not competitive with new natural gas generation in most locations.[6] And that's before even:

- accounting for the cost of new transmission required to enable entry and optimization of new clean technologies
- discounting for the disability that these new resources are intermittent and not dispatchable, except for limited intervals in the case of storage (excepting hydro).

This fact is inconvenient to renewable proponents wedded to RTO ideology.[7] And the fact is often obscured by claims that solar and wind plants and battery arrays are cheaper to operate than natural gas, and other fossil and nuclear plants. These claims are generally true, but of course paint an incomplete picture of the investment calculus, by ignoring relative capital costs per installed megawatt.

Yet clean energy new entry abounds in RTOs. Because while RTO markets have passed judgment on renewable entry, it's become blindly obvious these markets are not the final or only arbiter on the question. In fact, what markets "think" about the economics of new clean energy entrants has become increasingly irrelevant. The growing consensus is that we want these resources nevertheless and we want them quickly because they are crucial to realizing our grid transformation objectives.

RTO markets to date have passed judgment on clean energy technologies, and the resounding outcome is that, lacking government support and other revenue from outside the market, they are not competitive with new natural gas generation in most locations.

To this end, once their disobliging market signals are side stepped, RTOs hold a superficial appeal because a renewable developer can interconnect without impediment (in theory) from an incumbent transmission owner/operator and then sell its electricity to the RTO as the central counterparty in in the RTO's open markets. Let's break down this question of access.

A. Access To RTO Markets

In RTOs like SPP and MISO, markets at best play a distant supporting role in defining a resource mix. The composition of the supply stack instead has always been decided largely by state regulation of vertically integrated utilities (integrated resource planning).For a variety of reasons, utilities in these regions may seek to build resource portfolios that diverge from pure "market" outcomes. Fuel source diversity, tax subsidy drivers, environmental attributes, fuel cost hedging strategy, customer/regulator preferences, generator proximity to load, and perceived local economic development imperatives are all factors that influence the ultimate generation supply mix. Thus, a third-party renewable developer must establish a bilateral contract with a utility (or potentially a large retail customer) as a pre-requisite to sell in these regions – at least for all practical intents and purposes.

6. If wind, solar and storage investment was inherently cheaper (all in) than conventional fossil, as proponents often assert, governments worldwide are wasting vast sums advantaging these technologies unnecessarily. And there would be no call to action from respected voices like Paul Joskow:

> to recognize that the attributes of the electricity market liberalization initiatives that have taken place in the last 25 years or so are being threatened, not by the entry of intermittent generation at scale per se, but rather by the public policies that are trying to force systems to have very high penetrations of intermittent renewable energy whether or not this is economical based on market prices.

Id. at p.51.

7. The usual response is that these technologies, and older nuclear plants for that matter, would be competitive if only RTO prices accounted for the social cost of carbon. But they don't. Nor do they take into full account the social cost of polysilicon sourced in Xinjiang for use in solar panels, or environmental costs incurred in mining rare earth minerals for batteries, or the risk adjusted costs of storing nuclear waste.

Even in RTOs with deregulated utilities (California and ERCOT), including those with capacity markets (PJM, NY and NE) that were designed to manage resource adequacy and define the resource mix, access by renewables to these markets is underwritten by contracts with large retail buyers or state programs requiring the "deregulated" utility to contract to buy clean energy or through the creation of state authorities created to procure and contract for clean energy.

If you've noticed a theme, it's "contracts." Access by renewables to RTO environments (whatever their stripe) is all about contracts with the state, utilities or large customers, and that's no different a path than access offered to these resources in non-RTO markets. RTO prices – in energy, capacity and ancillary services markets – are not signaling the need for these resources to enter and displace existing fossil and nuclear plants. In fact, RTO prices are saying unmistakably there is no merchant opportunity for renewables in their markets because market prices alone are insufficient to support the investment in plant. Entry instead depends on out-of-market contracts and other subsidy support.

Again, there is nothing evil about this. We should accept, however, that an entrant supported by a state-mandated or large retail purchaser contract in an RTO is just a rate-base supported entrant under a different name. While we still use the terminology "organized market" as compared to "bilateral markets" to distinguish between RTO and non-RTO regions, in truth, both models today rely on bilateral contracting to support renewable penetration. Despite this similarity in access by contract, renewable supporters voice a preference for the RTO model over the traditional regulated environment. Why? What advantage do RTOs offer renewable developers over non-RTO utilities when it comes to access?

If you've noticed a theme, it's "contracts"... there is nothing evil about this. We should accept, however, that an entrant supported by state-mandated or large retail purchaser contract in an RTO is just a rate-base supported entrant under a different name.

First, all supply - renewable or otherwise, merchant or rate-base – interconnected to an RTO is guaranteed a buyer for its energy output, capacity value and ancillary services. In non-RTO regions there is no guaranteed market – just the bilateral offtake contract. And while, as noted, for a renewable resource, RTO market revenue usually isn't enough to cover the full cost and return needed to justify the investment, it is still material.[8] Of course, expected revenues earned by the resource in the RTO market do not end up as a windfall to the solar or wind supplier over and above the offtake contract price; they are accounted for in the contracting process. The contract counterparty (*e.g.*, the local utility or large retail customer) agrees to pay a guaranteed contract price that, alongside tax credits and other incentives, is sufficient to finance the solar or wind farm. But while guaranteed, the contract price is reduced by revenues realized by the renewable resource in the RTO markets.[9]

Herein lies the appeal of RTO markets to renewable developers and the contract buyers that enable their financing. Some portion of what the contract buyer pays the resource owner for its output is picked up by a third party through operation of the RTO market.

To illustrate, assume a $100 revenue stream is needed to make investment in the Sunny Solar Project viable. Big Tech Server Co. would like to procure the output of Sunny Solar to meet the corporate clean energy targets of its data center business. If Big Tech's server is located in a traditional utility region, its bilateral contract for the output of Sunny Solar will require a fixed price of $100 – end of story. If instead its server is located in an RTO, the ultimate price Big Tech pays under the contract is reduced by the revenues Sunny Solar will receive from the RTO. These revenues have the effect of materially reducing Big Tech's contract price.

8. Moreover, once the investment in plant is made, these revenues are almost guaranteed provided the sun is shining or wind blowing given the zero-marginal cost operating profile of renewable energy resources.

9. Sometimes these contracts are called "contracts for differences."

Other customers in the RTO, including those in other states, are unwittingly procuring and paying for a share of Big Tech's decision to contract with Sunny Solar in order to meet its clean energy targets. This does not necessarily mean these other customers are paying more than they would otherwise for the electricity they need, at least in the short-term. The zero-marginal cost Sunny Solar output procured by the RTO will displace some other existing resource, presumably one with higher marginal costs. The point is having other customers in RTOs unconsciously sharing in the $100 cost to procure contract-subsidized Sunny Solar obscures and dissipates the full cost of the Sunny Solar project. Additionally, it creates potential operations instability and reliability challenges by suppressing revenues in the RTO markets owed to other resources, including dispatchable resources needed to keep load and supply in real-time balance.

B. Access To Interconnection (the Queue)

A second, advantage RTOs offer is access to the queue – the path to interconnecting a resource to the transmission grid. Interconnecting through an RTO allows many patrons in the front door and into the lobby. But getting an actual seat in the theater to see the show is a different matter. PJM estimates the commercial probability that a given project entering the queue will reach commercial operation to be as low as 3%.[10] Interconnecting customers dealing directly with utilities in non-RTO regions will find fewer patrons in the lobby but those there are much more likely to hold valid tickets for seats to the show. The opportunity to get in an RTO queue, even if that means only getting into the lobby, we'll call "wide-open access." To use another analogy, "wide-open access" means everybody gets a free ticket to the lottery, with few ultimately claiming a prize, and no guarantee that the most deserving projects are amongst the winners.

The interconnection queues have become a modern-day version of the 1889 Oklahoma Land Rush, with RTO management and FERC playing the role of beleaguered land office agents attempting to resolve competing claims among the renewable project "Sooners."

PJM's queue is presently trying to process, in approximate numbers, an astounding 200,000 MWs of renewable energy projects – more than the RTO's existing 180,000 MWs of total installed generation![11] Wide-open access to interconnection sounds great, until the inevitable tragedy of the commons floods the queue with speculative projects of dubious merit obscuring and distracting from high-quality projects. Market forces at one time provided some discipline to the PJM queue, naturally limiting entry to projects whose economic viability was expected based on revenues from PJM's markets. When an interconnection project's viability is no longer driven by market revenues, but instead by out of market contract arrangements, this discipline disappears. No longer is there a force working to limit entry at the outset to quality projects and minimize entry of highly speculative, "have to be in the game, to win" type projects. The interconnection queues have become a modern-day version of the 1889 Oklahoma Land Rush, with RTO management and FERC playing the role of beleaguered land office agents attempting to resolve competing claims among the renewable project "Sooners."

Without the market naturally disciplining entry to the queue, perhaps the RTO could step in to exercise its independent judgment to identify and advance high-quality projects and summarily dismiss from the queue wildly optimistic or poorly conceived projects taking up time and resources? But hold on.

Although FERC insists on RTO independence, it has not vested, or cannot vest, the organization the executive authority needed to exercise this discretion.[12]

10. PJM 2021 Reserve Requirement Study at p. 33 (October 2021) https://www.pjm.com/-/media/planning/res-adeq/2021-pjm-reserve-requirement-study.ashx

11. A good generic description of the PJM conundrum was reported in: *Overwhelmed by solar projects, the nation's largest grid operator seeks a two-year pause on approvals*, Pittsburgh Post-Gazette, Feb. 3 2022; https://www.post-gazette.com/business/powersource/2022/02/02/pjm-interconnection-queue-energy-projects-electricity-grid-operator-backlog-approval-process/stories/202202020087

12. Admittedly, tariffs offer RTOs some discretion, for instance discretion to extend milestones or to instead hold an interconnection customer in default. But this authority is weak and an RTO trying to impose order is often second guessed by FERC or an interested state loathe to see any project, despite its infirmities, kicked out of the queue. A costly and time-consuming defense of a complaint at FERC is often the response an RTO gets to its attempt to discipline its wide open-access queue. *See, e.g., PJM Interconnection*, LLC, Docket No. ER22-634-000 (January 4, 2022) (challenging PJM attempt to cancel ISA for a 1600MW project in the queue for over 5 years with little evident progress towards construction and commercial operation).

No surprise then RTO queues find themselves in a state of dysfunction and federal litigation. Neutral, non-discriminatory, but undisciplined, wide-open access begins to frustratingly look like system planning by a blind and disinterested grid operator and planner. No surprise we've been hearing recent calls to create a public federal planning agency with interstate scope. To the extent this idea holds any appeal, we suspect existing regional planners could do a lot better in managing interconnection if they were charged with this same executive authority to curate among projects as is envisioned for a federal planning authority.

The point here is that the job of planning the transmission grid and managing interconnection to this grid calls for central coordination.

The point here is that the job of planning the transmission grid including managing interconnection to the grid calls for more central coordination and less "wide-open access."[13]

Somebody must be in charge; somebody must exercise what we call in our second paper "executive authority" even if that means acting as a gatekeeper. If we can't or won't charge RTOs with this authority, then one obvious alternative would be some big, federal agency or authority planning transmission and generation additions – not really unlike state-owned electricity companies that dominated in Europe, Australia, South America and elsewhere for much of the last century. Alternatively, we could embrace a regulatory paradigm that accepts the transmission owner as the natural monopolist, one vested in the business of building transmission provided proper regulatory incentives are set, and one naturally positioned to receive and coordinate state policy and preference when it comes to the grid and the types of resources attached to it. [14]

More executive authority means less "democracy" in actually making the decision, but it also means a more rapid planning decision and one more likely to ultimately get permitted and built.

While this second model surely borrows from the past, we are not saying let's return to the traditional vertically integrated utility monopoly that characterized the time before RTOs. We continue to see room for the RTO as a planning agent, system operator and market administrator but not one configured as we know them today. These regional transmission operators would be explicitly not independent, but accountable as instrumentalities to a collection of transmission owners. The functions of these operators would be regulated as functions of the public utilities that own or control them with federal rules demanding transparency, meaningful collaboration and inclusion with transmission customers, generators, state policymakers and state and local siting and permitting authorities. FERC can by rule establish standards and processes, but it will accept a reality (one that frankly already exists) that any decision to expand transmission infrastructure for reasons other than for reliability or economic efficiency of interstate wholesale electricity trades will be made by the transmission owner/planning agent and only after receiving the blessing from those states inextricably affected by the decision that the investment is in the interests of the ratepayer, accounting for all public policy interests the state and its citizens might have. More executive authority means less "democracy" in actually making the decision, but it also means a more rapid planning decision and one more likely to ultimately get permitted and built.

13. *Planning For The Future: FERC's Opportunity To Spur More Cost-Effective Transmission Infrastructure*, Gramlich and Caspary, Report for Americans For A Clean Energy Grid (January 2021) (citing William Hogan, p.44). https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf

14. What do we mean here when we say the transmission owner is "naturally positioned"? Consider the ample comment offered to FERC in its pending transmission planning ANOPR calling for the central planner to engage in "holistic," "comprehensive," "non-siloed," planning that integrates transmission with resource adequacy and interconnection – in other words, to engage in integrated resource planning. The problem, of course, is integrated resource planning is a function of state regulation of its public utilities, and not an authority vested in FERC and its regulation of RTOs.

III. ANOTHER MODEL

The challenge of transmission planning and expansion isn't the only force driving us to consider RTO alternatives. As RTOs search for a source of executive authority, states are impatiently filling the vacuum by more closely directing and controlling the system operator. What we called the "the quasi-governmental RTO" in our second paper is ascending. Even in multi-jurisdictional RTOs, regional state committees (like NESCOE, OMS and OPSI) are pushing to exercise greater control over the RTO, by urging representation on RTO boards, open board meetings, greater "transparency" into RTO decision-making and directing RTO section 205 filings before FERC.[15]

As noted, some argue a model where the state runs the RTO is not ambitious enough, and what we need is a *federal* central transmission planning authority to build out and operate a national "macro grid."[16] The last paper described our misgivings with state sponsored, quasi-governmental RTOs. In large part, these concerns are only amplified by the prospect of a federal agency performing system operations and planning. Still, we are not here to argue that public-ownership models for RTO operations must be dismissed as somehow anti-American or dangerously socialist.

For those, however, who still have faith in private enterprise, even if structural economic conditions require subjecting it to close regulation, they are losing the battle in proving that a private ownership model can work for system operations. The closest, albeit incomplete and unstable, example we have left in this country is the "member-driven" RTO. Their unworkable governance leaves them with a lack of executive authority needed to execute the changes to operations, planning and markets required to meet industry transformation. Either states will take them over to provide this authority, or we need to look at a different private model, grounded in well-established governance principles and sitting comfortably in a legally sound regulatory domain. As private-ownership model optimists, we appeal to FERC to:

> (1) Abandon "independence" as a governance principle because it is antipathetic to either an RTO that is an extension of a state (or federal) government or one that is a "member-driven" collective; and
>
> (2) Re-open itself to a for-profit, private-ownership model of regional system operator, ideally to replace the "member-driven" model, or at least to offer an additional path to support the collective regional action needed to support renewable transformation in a reliable and cost-effective manner.

Our opinion is that private ownership of regional network operators, incented and disciplined by regulation and profit motive, would execute state decarbonization agendas more quickly, efficiently and reliably than a member-driven customer/owner model. Of course, we're not asking for blind faith. But we would urge policymakers and FERC to at least be open to allowing the establishment of private models, alongside the current RTO options (member-driven or state owned).

15. The October 2020, "Vision Statement" published by NESCOE illustrates these kinds of state driven governance reforms. See, https://nescoe.com/resource-center/vision-stmt-oct2020/. For its part, OPSI commissioned a report in 2019 titled *Making Markets Work For PJM States*, that encouraged consideration of a role for OPSI in making section 205 filings to the PJM Tariff, with the goal of "increasing state's participation in – *and authority over* – PJM decision-making."https://opsi.us/wp-content/uploads/2019/10/Making-Markets-Work-for-PJM-States-10-14-19-1.pdf , p.11 (emphasis supplied). When an RTO delegates or otherwise cedes its section 205 rights, either to non-utility customer groups or to a regional state committee, through "jump ball" type mechanisms or explicit rules vesting 205 authority elsewhere beyond the RTO, we're unclear how the RTO remains a "public utility" under the Federal Power Act or how these arrangements conform to the "exclusive and independent authority" over tariff changes vested in RTOs by Order 2000 (subject only to those rights retained by transmission owning public utilities). This same type of question was raised recently by CAISO in questioning legality under the Federal Power Act of proposals seeking to establish interregional planning boards to sit above RTOs with section 205 rights over RTO tariffs. *Reply Comments of the California Independent System Operator*, Docket RM21-17-000, pps 39-51 (Nov. 30, 2021); https://elibrary.ferc.gov/eLibrary/filedownload?fileid=0F183FFD-BF35-CBA2-9DAD-7D72D7500000

16. *See, e.g., A U.S. Macro Grid Transmission Planning for 100% Clean Electricity*, White Paper, Energy Systems Integration Group (2021) ("The United States should establish a national transmission planning authority and initiate an ongoing national transmission planning process.") https://www.esig.energy/wp-content/uploads/2021/02/Transmission-Planning-White-Paper.pdf

What Would a Private Model Look Like?

As we insisted in our last installment, it's long past time to have a clear understanding of who owns (and thus who is in control and accountable for) grid operations functions and related market administration. At a high level it's a binary choice – either public (governmental) or private ownership.

International examples reveal both private and government owned system operators and market administrators – but in all cases ownership is clear. The ownership ambiguity problem really is unique to RTOs in this county. More specifically, it is unique to the member-driven, multi-state regional RTOs (PJM, ISO-NE, MISO, SPP). Single state RTOs are, or are becoming, instrumentalities of state government – with the advantages and disadvantages that follow from that.

...we're not asking for blind faith. But we would urge policymakers and FERC to at least be open to allowing the establishment of private models, alongside the current RTO options.

A private ownership model for grid operations and market administration backed by strong regulation does not mean setting the clock back to the 1980's with many individual balancing authorities administered by vertically integrated utilities. There is undoubted benefit to regional operations, regional planning and a unit commitment model that is blind to ownership and instead optimizes across reliability, economic and environmental constraints. A look to the past, as well as to some nascent developments occurring here in the South and West, and to examples in international settings offers proof that other, non-RTO, private ownership models offer promise to realize the benefits of regionalism and non-preferential unit commitment while at the same time being positioned to execute quickly on the new policy imperatives facing the industry (e.g., decarbonization, electrification, resilience, etc.).

(i) A Modified TRANSCO Model

When institutional options for system operators and their governance were debated at FERC in the late 1990s, the leading alternative to the ISO was the TRANSCO. TRANSCO as a species includes multiple sub-species representing variations on a theme; thus, the term tends to mean different things to different people. But when we use the term, we intend to describe a concept which involves a for-profit, private owner of the systems assets (transmission lines, substations, etc.) under the same corporate roof as the system operations functions.[17] The vision for a TRANSCO generally included a separation or unbundling of previously integrated utility functions. In other words, while a TRANSCO would own and operate transmission, it would not own or operate generation or provide retail electricity service. The National Grid Company in the United Kingdom is one of several prominent examples of a classic TRANSCO model operating today in Europe.

Unlike the UK and other international jurisdictions, state legislative actions in this country to liberalize the electricity industry sometimes directed full divestiture and other times ended up with a compromise where generation was "functionally unbundled" from transmission. Functional unbundling described the transfer of generation to a competitive affiliate of the utility holding company in lieu of divestiture to a wholly unaffiliated third-party.

The ownership ambiguity problem really is unique to RTOs in this county.

Surprisingly, twenty years on, what legislation in these states failed to accomplish fully – true unbundling - market forces and investor pressure largely is accomplishing. Today, so-called "deregulated states" all are rapidly approaching a place of full unbundling due to the sale in recent years of affiliated generation in "functionally unbundled," states either to independent power producers or private equity firms. As a result, this country is close to having:

17. Our apologies if this concept is known to some readers as a GRIDCO or WIRES-CO or by some other acronym. Additionally, because we intend TRANSCO to include operating the transmission system, including related market constructs, we are describing a broader concept than examples like Vermont Electric Power Company (VELCO) or American Transmission Company (ATC), entities also described as TRANSCOs.

1. Group 1 RTOs serving deregulated retail states where most generation is owned by independent merchants;
2. Group 2 RTOs serving regulated states where most generation is held or controlled by traditional vertically-integrated utilities; and
3. Generation owned or controlled by traditional vertically integrated utilities operating in states not served by an RTO.

What does this evolution mean when reconsidering a TRANSCO type model that would provide for private ownership of both the grid and grid operations? Given the legal separation of plants from wires, Group 1 RTOs above look particularly well suited to consider a TRANSCO type option. While CAISO, ERCOT and the three northeastern RTOs can be characterized as falling into Group 1, the TRANSCO ship may have sailed for single-state RTOs (CAISO, ERCOT and NYISO) where governance and control of system operations is already expressly, or trending toward, the public (governmental) model. This leaves "member-driven" ISO-NE and PJM.

An obstacle to creating TRANSCOs in the United States in the late 1990s was the tax and financial complication entailed in transferring transmission from individual transmission owners to the TRANSCO. This transfer and legal consolidation was essential to the model because transmission had to be spun off from the generating companies to prevent preferential self-dealing in transmission operations. But what if, as is generally the case in PJM and ISO-NE, legislative and/or financial forces have over the past 20 years or so worked to spin off generation from transmission companies? Why not then instead allow the individual transmission companies to continue to own their respective transmission assets while also allowing them to come together to form and own a separate venture to operate these assets?

This venture would of course provide the open access transmission service currently offered by the RTOs (PJM and ISO-NE), but invariably would also include market operations and logically regional planning. Theoretically at least, the only distinction at the end of the day, might be that instead of an RTO where ownership, control and accountability is unclear and widely dispersed, we're left with a governable "RTO" owned by transmission owners who are not just interested in, but dependent on, an environment that promotes efficient generation investment, retention and retirement.[18] So, no longer an RTO as defined by FERC, but not a classic TRANSCO because while transmission assets and operation of the system are controlled by transmission owners, they are not necessarily doing this in a single corporate structure, but instead retaining the individual transmission companies and collectively owning and controlling a separate venture to perform system operations. Let's call this "modified" TRANSCO, TRANSCO-M.

Where do integrated utilities, including municipal and public power companies, industrial customers, competitive retail electric providers, trading firms and merchant generators sit in a TRANSCO-M? The short answer is as customers and not likely owning or directly controlling governance and decision-making of grid operations and market administration. But if rule making falls to transmission owners wouldn't that inherently work inequitably and unfairly against other interests?

18. We say "RTO" in quotes because technically such an arrangement would not qualify as an RTO – for one thing, it would not be independent of market participants. But in a Group 1 world where generation is largely in unaffiliated merchant hands, query how accurate it is to describe the transmission owners who own and control the system operator as "market participants"?

While a TRANSCO-M would not be "independent" in the governance sense of an RTO, that's not to say it can't be made to operate in a just and reasonable fashion subject to Federal Power Act standards and assuring outcomes (in both grid and market operations) that optimize across economic, reliability and environmental constraints. Regulation need not be solely prescriptive. Regulation aligning the financial incentive of a for-profit operator with goals around efficiency and competitive metrics, could result in outcomes benefiting consumers that might surprise those who believe a financially disinterested system operator is the only way to go. Rules advanced by the TRANSCO-M will strike a balance among these competing constraints. This balance and the rules and structures used to strike this balance will vary from one TRANSCO-M to the next, with this variation largely reflecting differing policy preferences of states served by each TRANSCO-M.[19]

Unlike the RTO, which from time to time has acted as a vehicle to advance FERC's legally ambitious public policy initiatives, the role of the TRANSCO-M would be clearly understood as subject to state policies, such as those related to resource adequacy, clean energy targets, integrated resource planning and demand response. Grid and market operations would still remain subject to assertive (as opposed to "light-handed") FERC oversight and assessment by a fully independent market monitor – one whose employment or retention is not decided by the TRANSCO-M as grid operator. TRANSCO-M rule environments would of course meet federal standards for competitive, fair, non-discriminatory, just and reasonable, wholesale electricity transactions conducted in an environment that meets federal reliability standards. But this permits a broad spectrum of approach, as is evident today with operations in California, the desert Southwest, the Northeast, and the South all meeting Federal Power Act standards, notwithstanding their variety.

Unlike the RTO, which from time to time has acted as a vehicle to advance FERC's legally ambitious public policy initiatives, the role of the TRANSCO-M would be clearly understood as subject to state policy direction.

The takeaway? The case that regulation is inferior to a structural separation of transmission ownership from operations, with operations performed by an independent entity having no clear ownership or accountability, is weaker today than 20 years ago, because facts have changed. Not only facts, but what we are looking for from the industry also has changed. Environmental objectives are seeking generation resource and transmission infrastructure responses which differ from the reliability-constrained economic outcomes RTOs were designed to deliver. An approach that restores transmission company control over transmission planning and operations, disciplined by regulation but also incented by regulation to meet regional efficiencies in planning and operations, on balance, seems better positioned to advance our grid transformation objectives.

(ii) How Would Member Driven Group 1 RTOs Evolve Into a TRANSCO-M?

If the idea of a TRANSCO-M seems radical, the path to realizing one is quite straightforward. At least since 2005, FERC has reminded the industry that RTO membership is voluntary. Of course, it's only voluntary for transmission owners, and practically speaking, those transmission owners that have decided with the support of their state(s) to either join or refrain from joining an RTO. All other interests tied to the transmission system – merchant power plants, municipal/cooperative utilities, industrial customers, etc. - join or leave an RTO involuntarily, beholden to the transmission owner's decision. Whether RTO proponents like to admit it, the transmission owner always has naturally stood in the position of "first among equals" relative to other members in the RTO.

19. The TRANSCO-M arrangement promises to provide states a clearer and more direct path to having their electricity and climate policies objectives realized considering the historic and continuing regulatory relationship between states and transmission owners. This should be welcome news to states and environmental advocates that believe the RTO is thwarting state policies in this area. But of course, where state policy is not viewed as sufficiently progressive on climate matters, the TRANSCO-M model will leave little opportunity for advocates to pursue recourse at FERC. An RTO might present as an ill-defined vehicle to discharge electricity and climate policy direction coming from FERC. - ill-defined, but a vehicle, nonetheless. A TRANSCO-M, in contrast, would be driven quite explicitly by state policy objectives.

The voluntary character of RTOs means that like-minded transmission owners and states can withdraw from their existing RTO and constitute a TRANSCO-M to provide grid, market and planning operations in a manner that best reflects the policy preferences of their associated states. While governance will change, and likely so too will rules, this does not mean the TRANSCO-M would have to build systems and personnel expertise from scratch. Nothing would prevent existing RTO systems and personnel from performing the functions proscribed by the TRANSCO-M, either as employees or by way of contract.[20]

Admittedly, it strains imagination to expect a TRANSCO-M to cover a large and diverse footprint of states. Thus, it is easier to see a MISO, SPP or particularly a PJM fragmenting into smaller confederations if the RTO was replaced by transmission-owner created TRANSCO-M structures. Smaller but stronger TRANSCO-Ms with executive authority to execute on the policy preferences of their states would likely result. Disaggregation will sacrifice a degree of the efficiency that comes from broad regionalization. But there would still be room for a TRANSCO-M to agree with another TRANSCO-M or with its residual neighboring RTO to share "common market" functions, including retaining a centralized dispatch and economic unit commitment model, balancing markets, inter-regional planning and transmission services.

As mentioned, the TRANSCO-M model is probably irrelevant for those Group 1 RTOs that are quasi-governmental instrumentalities or heading in that direction. But for the private member-driven corporate RTOs in Group 1 (ISO-NE and PJM) TRANSCO-M should be considered as an alternative offering clear ownership (and the incentives and advantages that come from that clarity)[21] as well as providing operations more directly responsive to state policy preferences.

(iii) Can a TRANSCO-M Model Work For Group 2 RTOs And In Regions Today Where RTOs Do Not Operate?

Could the TRANSCO-M structure apply to regions where states have left their incumbent integrated (bundled) utilities in place? Here, the obvious concern is that a transmission system operator/market administer jointly owned and controlled by companies that also own or control generating assets, by definition, will not act in a disinterested manner.

Yet prior to RTOs, examples of both tight and loose power pools show competitors can come together regionally to achieve efficiencies for their customers, even if that means ceding control over dispatch and other operations. And when all is said and done, how much differently would we expect existing Group 2 (bundled) RTOs like SPP and MISO, to operate today if they were governed by their transmission owners and subject to clear regulation imposing standards of conduct and compliance with non-discriminatory Federal Power Act rules? After all, some would argue these RTOs today are essentially clubs run by their transmission owners in accordance with state policy directive.

The objection that most readily springs to mind is the plight of the merchant generator – an independent power producer ("IPP") whose livelihood depends on a dispatch blind to ownership and a market that provides revenues sufficient to attract and retain all economic investment. These IPPs are not to be confused with those whose investments are supported by a long-term power purchase agreement with an incumbent utility or large retail customer or supported by a state program (non-merchant IPPs). How could a truly merchant generator – dependent solely on market revenues – build a viable business plan in a TRANSCO-M, where the owners of the system operator/market administrator themselves own competing generation assets?

20. Indeed, establishing arrangements whereby the RTO continues to provide system operations, market administration and planning services sought by a TRANSCO-M formed by the departing transmission owners might settle arguments over the exit fee barrier erected in some RTOs to discourage transmission owners from leaving the RTO.

21. For example, the economic advantage of a private-ownership model might address the acute queue backlog problem in certain RTOs.While this problem is multi-faceted, a common complaint is that the RTO is understaffed, overworked and unable to process the volume of demand. One wonders how long this complaint would persist if the system planner was a private, for-profit firm incented to meet demand.

The answer is they probably can't, regardless of the firewalls that regulation could conceivably erect.[22] But consider the reality already facing the merchant IPP business today. True merchant plants are illusory in these Group 2 RTOs even today. We'd submit the reality largely looks like this:

1. Most truly merchant generation is already located in Group 1 RTO regions where states have deregulated and utility operations have been unbundled.[23]
2. Truly merchant generation is thermal generation. Non-merchant IPPs, including renewable generators, once connected to the grid are more often like partners alongside their integrated utility counterparties; consequently, they can be expected to have less concern with these parties operating the grid and making dispatch and unit commitment decisions.
3. If the future belongs to renewable resources, and their investment model is based on contracts or other support outside the market, as opposed solely on revenues from RTO markets, then we can expect a decreasing percentage of truly merchant generators and an increasing percentage of non-merchant IPP generation.
4. Finally, if the future belongs to renewable resources that produce electricity when they can with little regard to the dispatch and commitment decisions of the operator, how much concern should we really have when the operator making dispatch decisions is controlled by a collection of transmission companies that also own generation?

The point being there isn't much truly merchant generation operating in regions with vertically integrated utility transmission owners, whether in RTOs or not. And even less can be expected going forward seeing that a purely merchant model is usually unviable for renewable generation. The case that system operations must be separated from transmission ownership has certainly weakened. As far as separating system operations from generation ownership, notwithstanding the four observations above, we won't claim it's impossible to envision a scenario where a TRANSCO-M owned by bundled utilities would act with favoritism for one of its owner's resources or engage in discrimination masked as action needed for reliability reasons. But we should ask whether changed circumstances make these kinds of problems ones that regulation (establishing firewalls and data transparency), truly independent market monitors and technologies affording regulators better real time visibility, now can manage?

22. At the same time, it concedes too much to dismiss the idea that more robust and smarter regulation wouldn't improve the competitive environment even in cases where grid and market operations are affiliated with generation ownership. Early on Professor Hogan believed ringfencing conceivably could be viable in situations where operations and generation ownership was affiliated. *See* William Hogan, *Supplemental Comments on Testimony Before FERC IS0 Inquiry*, Docket No. PL98-5-00, (May 1,1998). available at http://ksgwww.harvard.edu/people/whogan~ (speaking of ring-fencing system operations functions). More recent reports have former FERC Commissioner Nora Brownell stating that:

> (a)lmost all data used in planning decisions is provided by incumbent transmission owner filings and it is not independently verified, but new technologies like those recognized in the FERC ANOPR can deliver independent data that can optimize system performance for planning decisions, and Department of Energy labs can verify it.

Trabish, H., *Gridlock in transmission queues spotlights need for FERC action on planning*, Utility Dive (July 19, 2021) https://www.utilitydive.com/news/gridlock-in-transmission-queues-spotlights-need-for-ferc-action-on-planning/603128/. This statement accurately recognizes the vital role transmission owners have controlling data that determines the operational capability and limits of the facilities they own. The data problem identified by former Commissioner Brownell isn't remedied by a structural separation of system operations from ownership – it's an issue in both RTO and non-RTO situations. And thus, it suggests more opportunity is available for FERC to regulate disclosure and verification rather than overestimating the degree to which a structural separation of operations from ownership solves fairness problems compared to models where transmission operations and ownership are kept together.

23. Those states that elected to unbundle utility operations created an environment to support merchant investment; those that chose not to did not see much merchant entry. Perhaps it's surprising to realize that viable merchant generation depends much more on state policies and actions, and less so on what FERC has done by way of open access and RTO formation.

IV. CONCLUSION

The analysis and observations set forth above are designed to answer a question: can we reasonably expect existing models for RTO governance to meet grid transformation objectives currently underway? There is a trending toward greater state control over RTOs and in certain single-state regions this control is explicitly formalized and others are coming closer by the day to having the RTO become a form of state agency.

State controlled RTOs will likely prove successful in pushing the transformation of the grid by increasing electrification and decreasing carbon emissions (assuming that is and remains the policy preference of the state in question). But by the end of this process, we doubt whether these systems will look anything like RTOs as we know them today. Certainly, as single-state political institutions they're unlikely to become very regional in scope.[24] And, being political in nature, it's reasonable to expect them to pursue policy by way of command/control and intervention, with less patience and a greater suspicion as to whether market paradigms can deliver on urgent policy objectives.

The uncertain question of ownership these RTOs face, leaves them too often being pushed and pulled in a struggle for control by stakeholders seeking to marshal the RTO as an instrument to advance their particular agenda.

As for member-driven, multi-state RTOs, they look and function a lot less "corporate" these days than in the past, with less executive authority and less independence from their members and other stakeholders. Whatever advantage some might see from this change, efficient decision-making producing coherent (as opposed to suboptimal compromised) programs, has not been the result. The uncertain question of ownership facing these RTOs, leaves them too often being pushed and pulled in a struggle for control by stakeholders seeking to marshal the RTO as an instrument to advance their particular agenda.

In the final analysis, FERC should be trying to promote regionalization in whatever form it might take.

We still think a private-ownership model for grid operations could prove superior to public ownership and that's why our papers have put multi-state, member-driven RTOs on the examining table.[25] It's time to reexamine axioms we've long held and compare them with the reality of the system as it is today and as it is evolving – a reality that is quite distinct from the scenarios and assumptions we accepted 20 years back.The world has changed and its trajectory looks quite different than it did 20 years ago when TRANSCOs failed to gain much traction and when we all accepted with little caveat that regulation was a poor substitute compared with a structural divestiture of system operations from control and ownership of transmission.

We are careful to use the term "reexamine" and not "reject." We're partial to approaches based on a private ownership of system operations by transmission companies, properly incented and disciplined by regulation. Plainly, many don't share our optimism. But we do believe we've raised sufficiently important and numerous limitations and problems with current RTO governance regimes to urge FERC to consider, with a broad mind, different private ownership regimes for regional grid and market operators alongside the current public (governmental) RTO model and the private (member-driven) RTO model.

24. This is a grave political economy problem considering the persuasive case many are making that efficient renewable penetration depends on a broad regional dispatch and interregional transmission planning.

25. A very different opinion is that the function and the urgent mission it faces are too important for the private sector. For example, a recent commentator in the realm of RTO governance advocates for a regime that would have the federal government essentially nationalize both grid operations and grid ownership. Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 CAL. L. REV. 209, 227 (2021).

In the final analysis, FERC should be trying to promote regionalization in whatever form it might take.[26] In so doing, it should lean-in where its jurisdictional prerogatives are the greatest. As a wholesale and interstate electric transmission regulator, FERC's jurisdictional wheelhouse is naturally in encouraging regionalization and efficiency. Its initiatives are weakest in forays into those areas where other entities – especially states – have a stronger basis under the law to take the reins. While it might also like to do everything within its power to promote decarbonization, its mandate is distinct from environmental regulators, and the states themselves. It should remain open to the idea that non-independent forms of system operator/market administrator might prove more expedient and effective to meet the goals that are shared by many states, while providing the public policy space to recognize the differences that exist across states and regions. It has already accepted non-independent public governance models such as CAISO, so this should, in theory, be no particular stretch. As far as private ownership models, the Commission should be receptive to both TRANSCO type options as well as other hybrids and confederations, both loose and tight, that promise a degree of joint or coordinated operations, competition and system planning.

26. Advice offered nearly 25 years ago remains instructive today:

> Perhaps most importantly, the Commission should provide a framework in which transmission market institutions have an opportunity to evolve efficiently. This has not been possible under the pervasive regulatory framework that has existed for 60 years. It will also not be possible if all utilities are now forced to adopt an ISO, or for that matter, any other single institutional structure.

Lenard, T., *The Electricity Journal, Getting the Transcos Right*, p. 52 (Nov. 1998)

Appendix 6

IT'S TIME TO RECONSIDER SINGLE-CLEARING PRICE MECHANISMS IN U.S. ENERGY MARKETS

By Mark C. Christie[*]

I. INTRODUCTION

For more than two decades, American power markets[1] operated by regional transmission organizations (RTOs)[2] have used "single-clearing price" (SCP)

* Commissioner, Federal Energy Regulatory Commission (FERC or Commission). Commissioner, Virginia State Corporation Commission (2004-2021). This article benefitted from a plethora of good suggestions, valuable criticism, historical recollections and technical assistance from many, including the author's former colleagues at the Virginia State Corporation Commission, Judith Williams Jagdmann and James C. Dimitri, and members of the Christie office team at FERC, including Neil G. Yallabandi and Regine Baus. The views expressed herein, however, are solely those of the author and do not necessarily represent the views of commenters, nor do they represent the official position of the Commission. The author does not express any opinion herein on any specific formal matter currently pending before the Commission or that may come before the Commission in the future, and nothing herein should be so interpreted.

1. Kathryne Cleary & Karen Palmer, *U.S. Electricity Markets 101*, RES. FOR THE FUTURE (Mar. 17, 2022), https://www.rff.org/publications/explainers/us-electricity-markets-101/. This article focuses on three major types of U.S. power markets. Described in more detail below, they include (i) real-time energy markets, in which physical electrical power is traded in real time, (ii) day-ahead markets, in which prices and commitments for next-day delivery of electrical power are traded, and (iii) capacity markets, in which promises to deliver power resources in the future, are sold, bought and priced.

2. "RTOs" are the regional transmission organizations that meet the criteria set forth in Final Rule, *Regional Transmission* Organizations, 65 Fed. Reg. 810 (1999) (to be codified at 18 C.F.R. pt. 35), Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), *aff'd sub nom.* Pub. Util. Dist. No. 1 of Snohomish Cty. v. FERC, 272 F.3d 607 (D.C. Cir. 2001); *see also* Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1, 554 U.S. 527 (2008) [hereinafter Order No. 2000]. Herein the term "RTO" also includes the single and multi-state Independent System Operators (ISOs) that qualify under Order No. 2000.

mechanisms. Such mechanisms are also used in power markets in the United Kingdom, Europe, Asia and other parts of the world.[3]

A single-clearing price mechanism broadly means that all sellers offering power or a power-related service receive the same clearing price. This clearing price is the *highest* price that it takes to meet full demand. As a result, sellers that have offered to sell at prices lower than the clearing price, including those offering at zero or even below zero due to out-of-market subsidies, still receive the highest clearing price. As consumers' power bills continue to rise, however, both the EU and UK are reconsidering whether the continued use of SCP mechanisms is in the best interests of hard-pressed consumers and whether changes to pricing structures need to be made to give consumers the full potential cost savings available from low to zero marginal cost resources.[4] Some experts experienced in RTO markets in the United States have recently begun questioning the continued use of single-clearing price mechanisms in American power markets as well.[5]

This article makes several arguments:

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3. *Action and measures on energy prices*, EUROPEAN COMM'N, https://energy.ec.europa.eu/topics/markets-and-consumers/action-and-measures-energy-prices_en ("The wholesale market in the EU is a system of marginal pricing, also known as pay-as-clear market, where all electricity generators get the same price for the power they are selling at a given moment. . . . The bidding goes from the cheapest to the most expensive energy source. The cheapest electricity is bought first, next offers in line follow. Once the full demand is satisfied, everybody obtains the price of the last producer from which electricity was bought."). On February 8, 2023, the author discussed with members and staff of the Central Electricity Regulatory Commission of India the use of SCP mechanisms in Indian power markets.

4. *See* Alice Hancock & Richard Milne, *Brussels plans energy market overhaul to curb cost of renewables*, FIN. TIMES (Jan. 1, 2023), https://www.ft.com/content/9c92f25d-26ee-40ae-b043-eb6cd7a22211 ("Brussels plans to overhaul the bloc's electricity market to prioritise cheaper renewable power . . . the commission suggests making renewable power more reflective of its 'true production costs', given that once the infrastructure is built, the energy source for a wind farm or solar array is essentially free."). *See also* Natalie Thomas, *UK looks to break link between soaring gas and power prices*, FIN. TIMES (Oct. 1, 2022), https://www.ft.com/content/b47e542c-de63-4f49-8ec6-9a459d28fe97 ("Pricing in Britain's wholesale electricity market, like on the continent, is based on 'short-run marginal costs.' Every electricity generator puts a bid in but the daily market price is set at the level that ensures there will be sufficient supply to meet demand. In other words, the price is always set by the most expensive plant . . . ."); John Norris & Rich Heidorn Jr., *EU Retreat from Competition, Ukraine Conflict Seen Impacting US Energy Markets*, RTO INSIDER (Sep. 19, 2022), https://www.rtoinsider.com/articles/30796-eu-retreat-competition-ukraine-conflict-impacting-us-energy-markets ("Europe appears to be retreating from electric competition and single-price clearing auctions, trends that could spread to the U.S., MIT professor Michael Mehling told the Independent Power Producers of New York. . . ."); Kate Abnett, *EU sets sights on energy market reform as prices soar*, REUTERS (Aug. 30, 2022), https://www.reuters.com/business/energy/eu-sets-sights-energy-market-reform-prices-soar-2022-08-30/ ("In the current system the EU wholesale electricity price is set by the last power plant needed to meet overall demand. Gas plants often set that price, which countries including Spain have said is unfair because it means cheap renewable energy is sold at the same price as costlier fossil fuel-based power.").

5. Tony Clark & Vincent Duane, STRETCHED TO THE BREAKING POINT RTOS AND THE CLEAN ENERGY TRANSITION, WILKINSON BARKER KNAUER, LLP (2021), https://wbklaw.wpenginepowered.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf (Clark is a former FERC commissioner and Duane was senior vice president of law, compliance and external affairs at PJM for many years); *see also* Bernard L. McNamee, *Time to Update Wholesale Electric Markets – But Don't Forget the Benefits of Traditional Utility Regulation*, REAL CLEAR ENERGY (Apr. 8, 2021), https://www.realclearenergy.org/articles/2021/04/08/time_to_update_wholesale_electric_markets__but_dont_forget_the_benefits_of_traditional_utility_regulation_771956.html. McNamee is also a former FERC commissioner.

First, that it is timely for the United States to join the UK and EU in a comprehensive reconsideration of the pricing mechanisms used in our power markets and to ask whether those pricing mechanisms can or will, in the future, deliver the best combination of cost savings and reliable power supply to consumers. It is especially timely to ask, as the EU is asking, whether single-clearing price mechanisms are best suited to deliver to consumers all of the potential cost savings from the increasing deployment of heavily subsidized, very low to below-zero marginal-cost resources such as wind and solar.[6]

Second, that the need for this reconsideration of pricing mechanisms should focus immediately on capacity markets. These constructs are critically important not only because of their impact on the costs consumers pay for power resources, but on the reliability of the power grid itself. Indeed, it is past time to reconsider whether such constructs, certainly those in the large, multi-state RTOs, are still capable of performing the important duties expected of them.

Third, that the reconsideration of SCP mechanisms in our power markets should not be limited to capacity markets. Unlike capacity markets, real-time energy and day-ahead markets use a different single-clearing price mechanism, the very granular SCP mechanism called Locational Marginal Pricing (LMP). While acknowledging that there are serious arguments in favor of continued use of the LMP mechanism in certain markets,[7] the article asserts that such arguments should not prevent an open-minded consideration of equally serious arguments made against continued use of single-clearing price mechanisms in U.S. power markets, including the practical question whether LMP itself, which may be effective in some scenarios, can continue to deliver what it promises under today's conditions.[8] Because of the vital role played by the real-time and day-ahead markets in balancing supply and demand, a rigorous reconsideration of SCP mechanisms such as LMP must proceed with care and caution, but it should proceed and it should not come with preconditions as to what can be reconsidered and what cannot be.

Fourth, the article emphasizes that any serious reconsideration of power market pricing mechanisms must include examining the broader historical context in

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6. Norris & Heidorn, *supra* note 4 ("[MIT professor Mehling] said [e]conomists and policymakers must determine whether single-price clearing markets still make sense as the fuel mix shifts to one dominated by low variable cost renewables that often produce negative prices.").

7. William W. Hogan, *Electricity Market Design and Zero-Marginal Cost Generation*, SPRINGER (Feb. 24, 2022), https://link.springer.com/article/10.1007/s40518-021-00200-9; Scott Harvey & William Hogan, *Locational Marginal Prices and Electricity Markets*, LMP MKT. DESIGN (Oct. 17, 2022), https://lmpmarketdesign.com/papers/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf. Hogan is the Raymond Plank Research Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. *Id*. He is one of the world's leading experts on power market design and in whose Kennedy School seminars the author has frequently enjoyed participating and learning. *Id.* Harvey is a consultant with FTI Consulting and a member of the California ISO/Western EIM Market Surveillance Committee. *Id.*

8. Clark & Duane, *supra* note 5.

which they were adopted, as they were key features of the power industry "deregulation"[9] movement of the late 1990s and early 2000s. Reconsidering these pricing mechanisms thus requires a candid reassessment of the assumptions that drove deregulation and whether those assumptions still apply to present reality. The use of single-clearing price mechanisms was integral to deregulation with its establishment of RTOs and RTO power markets. These "markets," however -- despite the label -- have never have been true markets, but rather administrative constructs with some market characteristics.[10] The questions about SCP mechanisms raised in this article cannot be divorced from the question whether these markets were based on deregulation assumptions that may no longer be valid, if they ever were.

Fifth, the article also emphasizes that, for those defending current single-clearing price mechanisms, it is not enough to argue purely from economic "textbook" theory and ignore the present realities driving market operations and results, especially in the large, politically diverse, multi-state RTOs.[11] Even the most ardent advocates of RTO markets admit that certain public policies, especially subsidies, that have been widely adopted since the advent of those markets, are antithetical to their efficient operation.[12] So any serious reconsideration of single-clearing price mechanisms cannot be confined to textbook economic theory, but must take into account how public policies have distorted the pricing mechanisms in RTO power markets that use marginal costs to determine outcomes and how these policies are likely to continue to do so. For if prices are the "keys to the RTO kingdom . . . what happens when price is no longer an effective tool for fulfilling the tasks that RTOs were created to complete?"[13]

So a serious reconsideration will evaluate how the messy real world of conflicting policies and politics, especially in the large, multi-state RTOs, affects their abilities to operate markets that deliver just and reasonable rates to consumers[14] and promote reliability.

Similarly, and especially with regard to capacity markets, a consideration of alternatives should ask whether accountability to the public in a democratic system is best served when it is elected state policy-makers and state regulatory authorities

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9. A note about terminology: What took place during this period was not the "deregulation" of a previously regulated electric power industry, similar to what took place with airlines, trucking and railroads in the 1970s, but a replacement of one heavily regulated construct with different ones. "Restructuring" is a more accurate term and came to replace the term "deregulation" as this fact became obvious. Nevertheless, for consistency, this article uses the term "deregulation" throughout. *See infra*, note 10.

10. Another note about terminology: This article uses the short-hand term "markets" for these administrative constructs known as RTO power markets, but the use of the term "markets" does not change the assertion herein that these are administrative constructs with some market characteristics, not true markets. As with the term "deregulation," the use of the term "markets" has always been more of a branding exercise by advocates than an accurate description, an exercise that George Orwell would recognize. *See supra*, note 9.

11. "[LMP] is the . . . *textbook* ideal that *should* be the target for policy makers." Hogan, *supra* note 7, at 17 (emphasis added).

12. *Id.* at 20 ("Subsidies produce unintended consequences and undermine the incentives provided by markets. . . . 'Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies.'") (internal citation omitted).

13. Clark & Duane*, supra* note 5, at 1.

14. Federal Power Act, 16 U.S.C. § 824d (2018); *see also* 16 U.S.C. § 824e (2005).

who have the clear and acknowledged responsibility to ensure their load-serving utilities have sufficient power resources to meet demand at prices consumers can afford, not RTO managers, RTO market participants and RTO member interest groups.[15]

Finally, as in any debate on a major issue of public policy, the most important question always evokes the Henny Youngman punch line "compared to what?" That is because choosing public policies *always* involves tradeoffs and any criticism of one policy must consider criticisms of alternative policies. So any serious reconsideration of single-clearing price mechanisms in U.S. power markets must evaluate just as critically the alternatives and their advantages and disadvantages. Without providing specific answers to the questions raised herein, the article asserts that the need to consider them is timely and compelling.

II. What Is a Single-Clearing Price Mechanism?

One of the most succinct and understandable descriptions of single-clearing price mechanisms and how they work in power markets is found in a U.S. Supreme Court opinion written by Justice Elena Kagan. It is worth quoting liberally herein. Referring to RTO power markets, Justice Kagan wrote:

> These wholesale auctions serve to balance supply and demand on a continuous basis, producing prices for electricity that reflect its value at given locations and times throughout each day. Such a real-time mechanism is needed because, unlike most products, electricity cannot be stored effectively. Suppliers must generate— every day, hour, and minute—the exact amount of power necessary to meet demand from the utilities and other "load-serving entities" (LSEs) that buy power at wholesale for resale to users. To ensure that happens, wholesale market operators obtain (1) orders from LSEs indicating how much electricity they need at various times and (2) bids from generators specifying how much electricity they can produce at those times and how much they will charge for it. *Operators accept the generators' bids in order of cost (least expensive first) until they satisfy the LSEs' total demand. The price of the last unit of electricity purchased is then paid to every supplier whose bid was accepted, regardless of its actual offer* . . . .[16] So, for example, suppose that at 9 a.m. on August 15 four plants serving Washington, D. C. can each produce some amount of electricity for, respectively, \$10/unit, \$20/unit, \$30/unit, and \$40/unit. And suppose that LSEs' demand at that time and place is met after the operator accepts the three cheapest bids. *The first three generators would then all receive \$30/unit.* That amount is (think back to Econ 101) the marginal cost—i.e., the added cost of meeting

15. FERC regulates RTOs and RTO markets to ensure just and reasonable rates to consumers, but FERC has no authority to order a load-serving public utility to build a specific generation facility, only states can. 16 U.S.C. § 824; *see also* Hughes v. Talen Energy Mktg., 578 U.S. 150, 154 (2016) ("The States' reserved authority includes control over in-state 'facilities used for the generation of electric energy.'" (quoting 16 U.S.C. § 824(b)(1)); 16 U.S.C. § 824o(a)(3) ("The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of *existing bulk-power system facilities*, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does *not* include any requirement to enlarge such facilities *or to construct new transmission capacity or generation capacity*.") (emphasis added).

16. FERC v. Elec. Power Supply Ass'n, 577 U.S. 260, 268 (2016) (emphasis added).

> another unit of demand—which is the price an efficient market would produce.[17] FERC calls that cost (in jargon that will soon become oddly familiar) the locational marginal price, or LMP.[18]

This is as good a basic description for non-lawyers and non-economists as one will find as to how a single-clearing price mechanism works. Justice Kagan is describing a specific SCP mechanism, LMP, which is used in American real-time and day-ahead power markets. RTO capacity markets, it should be noted, use single-clearing price mechanisms but do not use LMP, as we will discuss below.

The Harvey-Hogan paper, which strongly advocates for the continued use of the single-clearing price mechanism of LMP in real-time and day-ahead markets, offers additional detail about how this mechanism specifically works:

> [LMP] has two important characteristics. First, the prices are calculated from the system operator's actual operational security constrained economic dispatch solution for balancing load and generation. LMP prices support balanced supply and demand at each location and account for market participants bids and offers, the physical constraints of the transmission system and physical constraints on resource operation such as upper operating limits, and ramp rates. Second, LMPs settlements are based on market clearing prices, as opposed to pay-as-bid pricing designs used to determine . . . payments in non-LMP pricing systems. . . . A crucial element of LMP pricing is that it settles all resource injections and withdrawals at the same location at the same point in time at the same market clearing spot price. . . .
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> . . .
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> In LMP markets, prices can vary by location at each interconnection point (node) on the transmission system and by time in five-minute increments.[19]

The single-clearing price mechanism of LMP has three elements: an energy charge, a congestion charge and a charge for transmission system energy losses. Consequently, LMP can and usually does vary substantially across the RTO based on the presence of transmission constraints that prevent lower-cost generation from being dispatched.[20] These transmission elements in LMP can be valuable metrics in assisting RTO transmission planners: "[w]hen there are transmission constraints, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the price for their location."[21]

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17. *Id.* (citing Alfred E. Kahn, The Economics Of Regulation: Principles And Institutions 65-67 (John Wiley & Sons, Inc., 1971).

18. *Id.* (emphasis added). While giving appropriate kudos to Justice Kagan, in her more extensive explanation of RTO markets she also relied upon FERC's own Energy Primer as a key source for her explanation. *Id*. at 267-68 (citing FERC, ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS 58–59 (2015), https://www.ourenergypolicy.org/wp-content/uploads/2016/01/energy-primer.pdf). If it's good enough for Justice Kagan, it's good enough for the author, who will rely on the latest version of the ENERGY PRIMER, published in April 2020, herein. FERC, ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS (2020), https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf.

19. Harvey & Hogan, *supra* note 7.

20. ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS, *supra* note 18, at 64.

21. *Id*. at 65. See also Scott Miller, *Not 'sick or dying or dead': The great benefit of RTOs,* UTILITY DIVE (Mar. 23, 2023), https://www.utilitydive.com/news/rto-iso-benefits-regional-transmission-west/645776/

III. SCP'S CRITICAL ROLE IN THE DEREGULATION OF THE POWER INDUSTRY

Reconsideration of the use of single-clearing price mechanisms cannot be separated from an examination of what was called the deregulation[22] of the power industry during the 1990s and early 2000s,[23] because the use of such price mechanisms was a vital feature of the economic theory that underpinned deregulation and the RTO power markets created to implement it.

Deregulation was considered the textbook solution to the cost overruns of rate-based generation assets in the 1970s and 1980s, especially nuclear units.[24] During the movement's heyday in the late 1990s and early 2000s, deregulating states ordered their vertically integrated electric utilities to divest generation assets completely or at least "functionally separate" those assets into a separate generating company (a/k/a "genco") within a holding company structure.

The economic theory driving restructuring was that the wires network, which includes transmission and distribution components, was a natural monopoly and

("The grid that is dispatched as a network based on a Security Constrained Economic Dispatch (SCED) is very different from a grid based on the limitations of the contract path . . . . Thus, the RTO dispatch reveals transmission upgrades based on a fully utilized grid revealing areas of congestion on a larger view."); *Cf.* Clark & Duane, *supra* note 5, at 8-10 (discussion of the use of LMP in transmission planning).

22. *See supra* notes 9-10 (re terminology).

23. There were, of course, some antecedents to the deregulation movement of the 1990s. FERC's actions during that era were rooted, at least in part, in earlier legislative and regulatory efforts intended to use competition to protect consumers from exercises of market power by monopoly utilities. The literature recounting the history is voluminous and to recount it all here would be the fish that swallowed the whale. Among the most informative and well-written accounts are: Hon. Joseph T. Kelliher, *Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission*, 26 ENERGY L.J., 1, 5-11 (2005) (Kelliher is a former member and chairman of FERC); Harvey Reiter, *The Contrasting Policies of the FCC and FERC Regarding the Importance of Open Transmission Networks in Downstream Competitive Markets*, 57 FED. COMM. L.J. 243, 255-61 (2005) (detailing the history of efforts to open up access to transmission assets prior to Order No. 888); Harvey Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts*, 18 LAND AND WATER L. REV. 1, 3-10 (1983) (which was prescient in forecasting and advocating for the type of open access to monopoly-owned transmission networks that was enacted in FERC Order No. 888 over a decade later - both Kelliher and Reiter 2005 highlight the important role of the Public Utility Regulatory Policy Act (PURPA), Pub. L. 95-617, 92 Stat. 3117 (Nov. 9, 1978) in laying the groundwork for the deregulation of the 1990s, because PURPA required monopoly utilities to purchase power, under certain circumstances, from a new class of generators which were not owned by the utility). For a well-written and persuasively critical view of deregulation's early phase, including FERC's role, *see* Tyson Slocum, *The Failure of Electricity Deregulation: History, Status and Needed Reforms,* FED. TRADE COMM'N (Mar. 2007), https://www.ftc.gov/sites/default/files/documents/public_events/Energy%20Markets%20in%20the%2021st%20Century:%20Competition%20Policy%20in%20Perspective/slocum_dereg.pdf.

24. *The Contrasting Policies of the FCC and FERC Regarding the Importance of Open Transmission Networks in Downstream Competitive Markets*, *supra* note 23, at 251; *see* Mark C. Christie, *Economic Regulation in the United States: The Constitutional Framework*, 40 U. RICH. L. REV. 3, 949, 968-69 (2006) (providing a discussion of the famous (at least among utility lawyers) U.S. Supreme Court opinion in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989) which arose out of this era and involved denial of cost recovery through rate base of the pre-construction costs for proposed but never completed nuclear power plants in Pennsylvania). *Duquesne Light* is probably the most recent time the Supreme Court evaluated those ubiquitous terms "just and reasonable" rates in the context of a Takings Clause claim under the Fifth Amendment. *See generally* 488 U.S. 299.

should remain regulated under the long-used cost-of-service model.[25] By the 1990s, for a variety of reasons, including the development of highly efficient combined-cycle gas turbine generators, there was general agreement that generation was no longer a natural monopoly.[26] So deregulation advocates argued that generators should be subjected to a competitive marketplace and seek their revenues through efficient operation and economic dispatch, not from the guaranteed revenue stream provided in rate base.[27] In response, states passing deregulation laws generally required the incumbent utility's generation resources to give up the guaranteed revenues that came from including generation assets in rate base. Instead, generation assets were required to seek revenues in newly-established RTO power markets, where they would compete with independent power producers (a/k/a "merchant generators"). According to the theorists, the most efficient generators would be winners in this competition for revenues, whether utility-owned or independent. The inefficient generators, denied guaranteed funding from rate basing, would be the losers and be forced to retire. All risk would be shifted from consumers to investors, or so the theory went.

FERC was no passive bystander in the deregulation movement; on the contrary, arguably FERC launched it with Order No. 888,[28] which required all jurisdictional public utilities to make their transmission assets available for interconnection and use by generators without regard to whether generators were utility-owned or independent. While Order No. 888 was within FERC's jurisdiction and consistent with a history of promoting competition,[29] there were undeniable tradeoffs. It created enormous pressure on states to deregulate. Generators in one state, both merchant and utility-owned, could now use their access to interstate transmission to undercut another state's regulated utilities which owned rate-based units *that customers had to pay for whether they dispatched or not*. This new reality created by Order No. 888 undermined both state regulators' authority over

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25. *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts*, *supra* note 23, at 8 ("the transmission of electric power is generally acknowledged to possess natural monopoly characteristics") (citing James Meek, *Concentration in the Electric Power Industry: The Impact of Antitrust Policy*, 72 COLUM. L. REV. 64 (1972)). There remains debate to the present day whether transmission, which includes both regional and local elements, is a natural monopoly. This article takes no position on that issue.

26. Kelliher, *supra* note 23, at 5-6.

27. "Rate base" is a term from cost-of-service regulation. Load-serving utilities are allowed to put assets (distribution, transmission and generation) into "rate base" and then recover in rates paid by customers depreciation costs over the lives of the assets, as well as a profit on the value of the assets in the form of return on equity, referred to in shorthand as "ROE." The setting of ROE is often the most important and contentious issue in a rate case.

28. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*; 75 FERC ¶ 61,080 (1999) ; *order on reh'g*; 78 FERC ¶ 61,220 (Order No. 888-A);, *order on reh'g*; 81 FERC ¶ 61,248 (1997) (Order No. 888-B); , *order on reh'g*,; 82 FERC ¶ 61,046 (1998) (Order No. 888-C), *aff'd in relevant part sub nom.;* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.;* New York v. FERC, 535 U.S. 1 (2002).

29. *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts*, *supra* note 23, at 3*; see also* Kelliher, *supra* note 23, at 1.

their own state utilities' resource planning and their ability to seek the optimal balance between generation and transmission costs.[30]

FERC then pushed way beyond Order No. 888. In the much more intrusive Order No. 2000, issued in 1999,[31] FERC created modern RTOs and shifted the deregulation movement into overdrive. Order No. 2000 made it crystal clear that FERC wanted *all* state-regulated public utilities to join federally-regulated RTOs.[32] This new goal expanded from ensuring open access to transmission assets to transferring effective control over those assets to the RTOs.[33] Just as significantly, pushing all utilities into RTOs meant that the transmission *planning function* itself was removed from the state-regulated public utilities and thus simultaneously removed from oversight by state regulators.

Transferring responsibility for transmission planning to the RTOs, even in states in which utilities remained vertically integrated, made it far more difficult, if not impossible, for state regulators to oversee effectively and comprehensively their state utilities' planning and construction of transmission, distribution and generation facilities, known as integrated resource planning, or "IRP." Overseeing the IRP process had long been one of the states' most effective tools for ensuring just and reasonable *retail* rates and reliable service, the two chief goals of state utility regulation. The IRP process enabled state regulators to balance the need for one type of proposed resource, be it generation, transmission, distributed energy or demand-side, against other alternatives, potentially of lower cost.[34]

In addition to taking over the transmission planning function from the utilities and their state regulators, the RTOs created under Order No. 2000 were charged with operating the regional power markets that were integral to deregulation and which would use single-clearing price mechanisms.[35]

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30. Slocum, *supra* note 23 at 3-4 ("Reliable planning and operation of a bulk supply system requires full coordination between generation and transmission and this functional separation made coordination much more difficult . . ."). Another one of the legacies of Order No. 888 has received much less attention but may have affected consumer costs significantly. The unbundling of transmission assets from distribution and generation meant that most rate regulation of transmission costs was transferred from state regulatory authorities to FERC, which offered transmission owners the formula-rate recovery mechanism. Formula rates are procedurally much more attractive to the transmission owner, and often much more generous than most state rate recovery mechanisms, in which the utility bears the burden of proving that costs are reasonable and prudent. The consequences of this transfer of rate authority to FERC and its impact on transmission costs to consumers are not the subject of this article, but they deserve one.

31. Order No. 2000, *supra* note 2.

32. *Id.*

33. *Id.* Order No. 2000 said its goal was "for *all transmission-owning entities in the Nation*, including non-public utility entities, to place their transmission facilities *under the control of the appropriate RTOs*." *Id.*

34. McNamee, *supra* note 5 ("In traditionally regulated markets, investor-owned utilities submit detailed integrated-resource plans that explain how they will meet future electric needs through a mix of generation resources.").

35. *Wholesale Electricity Markets and Regional Transmission Organizations*, AM. PUB. POWER ASS'N, https://www.publicpower.org/policy/wholesale-electricity-markets-and-regional-transmission-organizations.

While Order No. 2000 clearly intended that all public utilities would join the new RTOs, its text was not explicitly mandatory.[36] Many state-regulated utilities in the Southeast and West resisted doing so. In response, just a few years after Order No. 2000, FERC proposed *mandatory* RTO membership for *all* state-regulated public utilities, in its misbegotten Standard Market Design proposal.[37] After sparking a firestorm of opposition in Congress and from state officials, this proposal crashed and burned.[38] It was perceived – accurately -- as a glaring and ill-considered example of federal hubris and encroachment on the states' core retail-rate regulatory authorities, which are essential to regulation in the public interest.

Standard Market Design was "the bridge too far" that reversed the momentum of deregulation. Most states that deregulated did so before 2005, with various forms being adopted. Some early adopters went as far as full retail choice in which retail customers could choose among different, allegedly competitive, retail power marketers, and load-serving utilities were required to divest their generating assets.[39] Other states retained the monopoly model for retail sales to end-user customers but required their incumbent load-serving utilities to obtain power and capacity in RTO markets.[40] Some others reversed course before full retail choice was implemented and returned to the vertically-integrated, cost-of-service model, albeit within an RTO, with utilities still owning generation assets.[41]

As both the history of Order No. 2000 and the Standard Market Design proposal demonstrate, participation by utilities in RTOs was an integral part of the deregulation agenda and serves as a rough proxy for whether a state deregulated, at least in some form or degree. Deregulation was always about much more than whether a state's load-serving utilities shopped for power supply in power markets, but in those markets the use of SCP mechanisms has always been a key feature.

36. *Electricity Markets – 101*, NAT'L GOVERNORS ASS'N, https://www.nga.org/electricity-markets/#:~:text=FERC%20Order%202000%20encouraged%20utilities,is%20owned%20by%20non%2Dutilities.

37. Request for comments, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,563 (2002), 67 Fed. Reg. 76,122 (2002).

38. Order terminating proceeding, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 112 FERC ¶ 61,073 (2005). Mandatory RTO membership was proposed by a Commission under a chairman appointed by President George W. Bush, so FERC's role in pushing its regulatory reach too far, from the ill-conceived federal overreach in Order No. 2000 during the Clinton administration into the even more sweeping Standard Market Design proposal during the second Bush administration, was certainly bipartisan.

39. FED. TRADE COMM'N, COMPETITION AND CONSUMER PROTECTION PERSPECTIVES ON ELECTRIC POWER REGULATORY REFORM: FOCUS ON RETAIL COMPETITION (2001), https://www.ftc.gov/sites/default/files/documents/reports/competition-and-consumer-protection-perspectives-electric-power-regulatory-reform-focus-retail/electricityreport.pdf; *see also* Slocum, *supra* note 23; *see also* Borenstein & Bushnell, *infra* note 56.

40. *Id.*

41. Virginia provides such an example. 2007 Va. Acts ch.. 933 (April 4, 2007).

IV. DEREGULATION AND CONSUMER COSTS

Whether the deregulated models overall have, in practice, been better for consumers than the state-regulated, cost-of-service constructs may still be a matter of debate,[42] but there is persuasive evidence that deregulation provided no real cost savings to consumers; indeed, the empirical data available suggests that it actually has made power more costly for consumers in deregulated states.[43] Data from the U.S. Energy Information Administration and other sources has consistently showed a general pattern of *higher* residential electricity rates in most RTO states than in non-RTO states.[44] Since RTO participation was integral to deregulation, comparing rates in RTO and non-RTO states provides relevant context to a reconsideration of the pricing mechanisms that are also part of deregulation's legacy.[45]

Further, the question whether deregulation itself has actually saved consumers money is obviously relevant to any reconsideration of SCP mechanisms, since deregulation was advocated as a way to reduce costs to consumers, as well as shifting risk to investors.[46]

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42. James Downing, *After a Quarter Century, Industry Experts Still Split on Restructuring*, RTO INSIDER, (Jan. 17, 2023), https://www.rtoinsider.com/articles/31446-after-quarter-century-industry-experts-split-restructuring.

43. Alexander McKay & Ignacia Mercadal, *Deregulation, Market Power, and Prices: Evidence from the Electricity Sector*, MIT CTR. FOR ENERGY AND ENV'T POL'Y RES. (Apr. 2022), https://ceepr.mit.edu/workingpaper/deregulation-market-power-and-prices-evidence-from-the-electricity-sector/ ("We find that the increase in markups dominates despite modest efficiency gains, leading to *higher consumer prices and lower consumer welfare* [from deregulation].") (emphasis added); *see* Penn, Ivan, *Why Are Energy Prices So High? Some Experts Blame Deregulation*, N.Y. TIMES, (Jan. 4, 2023), https://www.nytimes.com/2023/01/04/business/energy-environment/electricity-deregulation-energy-markets.html ("Average retail electricity costs in the 35 states that have partly or entirely broken apart the generation, transmission and retail distribution of energy into separate businesses *have risen faster than rates in the 15 states that have not deregulated*. . . . That difference has persisted for much of the last two decades or so. . . . On average, *residents living in a deregulated market pay $40 more per month for electricity* than those in the states that let individual utilities control most or all parts of the grid. *Deregulated areas have had higher prices as far back as 1998*." (emphases added)); *see also* Scott Patterson & Tom McGinty, *Deregulation Aimed to Lower Home-Power Bills - For Many, It Didn't*, WALL STREET J. (Mar. 8, 2021), https://www.wsj.com/articles/electricity-deregulation-utility-retail-energy-bills-11615213623 ("Retail energy companies compete with local utilities to give consumers more choice. *But in nearly every state where they operate, retailers have charged more than regulated incumbents, a Wall Street Journal analysis found*.") (emphasis added)); Slocum, *supra* note 23, at 5-6. While not the subject of this article, one reason deregulation may have provided no cost savings to consumers is because many states already had relatively low rates under their traditional cost-of-service models, so there was nothing for deregulation to "fix." And it may have increased costs for consumers in deregulated states because by removing authority over transmission planning from states to RTOs, state regulators could no longer conduct integrated resource planning that balanced the costs of generation, transmission and other resources and sought the most cost-effective mix.

44. *State Electricity Profiles, Data for 2021*, U.S. ENERGY INFO. ADMIN. (Nov. 10, 2022) https://www.eia.gov/electricity/state/unitedstates/.; *see* Robert Mullin & James Downing, *A 'Deregulation' Debate by the Numbers*, RTO INSIDER (Jan. 16, 2023), https://www.rtoinsider.com/articles/31452-a-deregulation-debate-by-the-numbers ("McCullough contends that prices in RTO areas can be more sensitive to [price spikes] because RTOs rely on the single market clearing price mechanism to set prices, as opposed to the 'price-as-bid' nature of the traditional utility model."). *See* Slocum, *supra* note 23, at 5-6.

45. Downing, *supra* note 42 ("RTOs were created to lower costs to end-use consumers but have failed to do so, said Public Citizen's Energy Program Director Tyson Slocum.").

46. The author was a fact witness to such claims, serving as the director of policy for the governor of Virginia in the mid-1990s when deregulation was being promoted in Virginia as a way to reduce power costs,

V. DEREGULATION AND RELIABILITY

Not only was deregulation supposed to save consumers money, it was supposed to promote reliability. So it is also pertinent to ask whether RTO markets, especially the multi-state capacity markets, have been successful in ensuring a sufficient supply of the power necessary to sustain reliability.

The experience of ERCOT[47] – the purest example of a market approach to reliability through use of SCP scarcity pricing -- during Winter Storm Uri[48] should disabuse anyone but the most committed theorist of the belief that a pure market approach will be effective in ensuring reliability during extreme weather and unanticipated demand spikes.[49] Winter Storm Uri triggered controlled outages affecting more than four million customers, leaving many customers in Texas without power for days as power supplies were inadequate despite scarcity pricing.[50] Nor should ERCOT's market design be seen as a problem unique to Texas. Similar problems with the threat of critical supply shortages are growing in all the FERC-regulated RTOs as well, including several with capacity markets.[51] In these FERC-regulated markets, market design and the use of single-clearing price mechanisms cannot be summarily excluded from the discussion about the growing threat of supply shortfalls.

Another facet of the reliability question that should be examined is the so-called "missing money" problem.[52] For one thing was certain about deregulation and the move to RTOs and RTO markets. All the states that did adopt some form of it, as well as the RTOs they joined, faced one unavoidable question when it

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especially for the large industrial customers who were among the most vocal advocates. He began his service a few years later as a member of the Virginia State Corporation Commission, the state utility regulator, shortly after Order No. 2000 had established RTOs. FERC's Standard Market Design, which mandated RTO participation, was still pending when he sat on his first major utility case, to decide whether to allow Virginia's largest utility, Dominion Virginia Power, to enter the regional RTO, PJM Interconnection. *In the matter concerning the application of Virginia Electric and Power Company d/b/a Dominion Virginia Power for approval of a plan to transfer functional and operational control of certain transmission facilities to a regional transmission entity*, COMMONWEALTH OF VA. STATE CORP. COMM'N: EX PARTE, Case No. PUE-2000-00551 (Nov. 10, 2004). On deregulation advocates' promises of reduced consumers costs and shifting of risks, see Slocum, *supra* note 23, *supra* note 45, and Borenstein & Bushnell, *infra* note 56.

47. *About ERCOT*, ERCOT, *https://www.ercot.com/about.* Electric Reliability Council of Texas (ERCOT) is the ISO for most of Texas in terms of both load (roughly 90%) and geographic footprint. *Id.*

48. *Winter Storm Uri Spread Snow, Damaging Ice from Coast to Cost, Including the Deep South*, WEATHER CHANNEL (Feb. 16, 2021), https://weather.com/safety/winter/news/2021-02-14-winter-storm-uri-south-midwest-northeast-snow-ice.

49. McNamee, *supra* note 5 ("[A] big disconnect in the electric markets is that no one has an obligation to serve customers.").

50. *Id.*

51. NERC, 2022 LONG-TERM RELIABILITY ASSESSMENT (2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf [hereinafter NERC LTRA 2022].

52. Murty P. Bhavaraju et al., *PJM Reliability Pricing Model - A Summary and Dynamic Analysis*, IEEE XPLORE (June 2007), https://ieeexplore.ieee.org/document/4275491 ("[S]ince the peaking generation needed to meet the adequacy criterion will not receive enough revenue from the energy market to justify investments, other revenue streams are needed to ensure that they cover their fixed costs. *The gap between the net revenues and fixed cost of generation is referred to as 'Missing Money.'*" (emphasis added)).

came to reliability: *How do we make sure the lights stay on in this brave new world of competing generators with no guaranteed revenues?* That is, what about the "missing money?" With rate base revenues gone, there was an entirely justifiable fear that energy market revenues alone would not attract sufficient generation investment to keep the lights on at times of peak demand, a threat exacerbated by the adoption of price caps in energy markets in many deregulated states.

Only one deregulated state -- Texas with the ERCOT model -- decided to go the "full Monty" on deregulation, adopting retail choice and depending entirely on a real-time energy market with scarcity pricing to attract enough generation resources to keep the lights on.[53] Not being willing to gamble like Texas on an energy-only market construct, several other RTOs and deregulated states turned to something else.

VI. THE USE OF SCP MECHANISMS IN U.S. CAPACITY MARKETS

In the eastern RTOs – ISO New England Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO) and PJM Interconnection LLC (PJM) – several (though not all) states adopted a deregulated model in which their load-serving utilities got entirely out of the generation business and all generators were forced to compete in RTO markets.[54] In contrast to Texas, however, to deal with the "missing money" problem, administrative constructs called "capacity markets" were created.[55] If the unavoidable question of deregulation was *how do we keep the lights on when generators no longer have dependable revenues from rate basing,* it turned out the answer in these RTOs was: *We will continue to give them dependable revenues called "capacity payments."* The creation of these markets necessarily conceded that investors *must* have certainty as to future revenues – and specifically that RTO energy market revenues alone are not enough to encourage investment in capital-intensive generation. The creation of these markets also destroys any argument that deregulation was all about shifting investment risk for generation assets from consumers to investors.[56] It never was, certainly not where capacity markets were established to provide the "missing money" to investors.

PJM describes its own capacity market this way:

53. After the crucible of Winter Storm Uri, Texas is considering a major redesign of its markets to attempt to improve their reliability performance through payments to generators outside of the energy market. Naureen S. Malik & Mark Chediak, *Texas Regulator Backs Plan to Pay Power Plants to Bolster Grid*, FINANCIAL POST, (Jan. 19, 2023), https://financialpost.com/pmn/business-pmn/texas-regulator-wants-to-pay-power-plants-to-help-avoid-deadly-blackouts ("Texas regulators are throwing their support behind a plan to pay electric plants to be on standby to provide backup electricity to the state's grid to help avoid a repeat of the deadly blackouts during a 2021 winter storm. . . . Previous attempts to start similar programs, called *capacity markets*, in Texas have been defeated in the last decade.") (emphasis added).

54. Slocum, *supra* note 23 at 2-5; *see also* Borenstein & Bushnell, *infra* note 56.

55. *PJM Interconnection, LLC*, 117 FERC ¶ 61,331 at PP 1-2 (2006) (approving PJM's capacity market construct).

56. Severin Borenstein & James Bushnell, *The U.S. Electricity Industry After 20 Years of Restructuring* (Nat'l Bureau of Econ. Rsch., Working Paper No. 21113, 2015) ("*We argue that the greatest political motivation for restructuring was rent shifting, not efficiency improvements*, and that this explanation is supported by observed waxing and waning of political enthusiasm for electricity reform.") (emphasis added).

"The essential elements of the capacity market are:

- Procurement of capacity three years before it is needed through a competitive auction
- Locational pricing for capacity that varies to reflect limitations on the transmission system
- A variable resource requirement curve, which is the demand formula used to set the price paid to market participants for capacity and the amount of capacity

Capacity market participants offer power supply resources into the market that provide supply or reduce demand. These resources include new and existing generators, upgrades for existing generators, demand response (consumers reducing electricity use in exchange for payment), energy efficiency and transmission upgrades. When a participant offers these resources into the market, *that participant is committed to increase supply or reduce demand on the PJM system by the amount they offered, three years in the future*."[57]

If there are insufficient offers on the supply side – in other words, if not enough capacity is offered to meet the administratively set demand curve -- then all sell offers theoretically could even reflect a price based on a constructed value (Cost of New Entry or CONE) inflated by a subjective multiplier.[58] The resulting price would purportedly represent the scarcity price that is supposed to bring new supply rapidly into the market. This method is the SCP mechanism on steroids, paying suppliers not just the highest clearing price but an administratively set price potentially higher even than the price of the highest offer.

While there is variation across the capacity market constructs used in RTOs, all capacity markets use a single-clearing price mechanism and all pay winning sell offers the *highest* clearing price, even those offered at prices far below their actual costs due to subsidies.[59] None of the RTOs use a nodal price (such as LMP) as an element of the single-clearing price mechanism in their capacity markets.[60] They use instead zonal pricing based roughly on load-serving entity territories and data on transmission constraints, including the use of sub-zones within those territories.[61] Zonal SCP mechanisms may provide more granular price signals than an RTO-wide price, but nowhere near the granularity of LMP. So the arguments for the value of LMP's highly granular, nodal price signals, offered to justify its

57. *Capacity Market (RPM)*, PJM, https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets (emphasis added); ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS, *supra* note 18, at 88. NYISO conducts three capacity auctions: six-month, monthly and spot. *Id.* at 83. ISO-NE conducts a three-year forward auction. *Id*. at 78. MISO conducts an annual *voluntary* resource auction. *Resource Adequacy*, MISO, https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc%3B; *see* ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS, *supra* note 18, at 94.

58. PJM Open Access Transmission Tariff, Attachment DD, § 5.10(a)(i), https://pjm.com/directory/merged-tariffs/oatt.pdf.

59. *Wholesale Electricity Markets and Regional Transmission Organizations*, AM. PUB. POWER ASS'N, https://www.publicpower.org/policy/wholesale-electricity-markets-and-regional-transmission-organizations-0#:~:text=Energy%20prices%20paid%20in%20these,meet%20the%20demand%20for%20power.

60. U.S. GOV'T ACCOUNTABILITY OFF., ELECTRICITY MARKETS: FOUR REGIONS USE CAPACITY MARKETS TO HELP ENSURE ADEQUATE RESOURCES, BUT FERC HAS NOT FULLY ASSESSED THEIR PERFORMANCE (2017), https://www.gao.gov/assets/gao-18-131.pdf.

61. *Id.* at 15-22.

use in real-time and day-ahead markets, simply do not apply as a defense of capacity markets.

One justification for capacity payments, however, does make sense. Power markets, unlike real markets, cannot tolerate shortages while waiting for suppliers to respond to price signals and produce more supply to meet demand. *Contra* Texas, we cannot run the risk of waiting to see if scarcity pricing alone in energy markets is incentive enough to balance power demand with sufficient power supply during times of peak demand and tight supply.[62]

Not willing to take the chance of depending on either energy or capacity markets for resource adequacy, many states, even in RTOs, remain vertically-integrated and continue to allow their load-serving utilities to keep generation resources in rate base or procure power through bilateral contracts. In MISO, the capacity market is only residual and most MISO states remain vertically integrated with generation-owning utilities. SPP,[63] in which all states remain vertically integrated, does not operate a capacity market at all, nor does the California Independent System Operator (CAISO). And, of course, many states in the Southeast, Pacific Northwest and Rocky Mountain regions did not deregulate at all, nor join RTOs, much less depend on capacity markets for resource adequacy.

In practice, capacity markets do not procure physical electrical power, but rather a future *pledge* to deliver power when needed to meet a *predicted* demand peak at emergency times.[64] Both the resources the RTO deems available to deliver power at the future emergency point in time, as well as the predicted demand at that future point in time, are unavoidably speculative. If actual demand at the future point is significantly higher than the prediction, a supply shortfall and outages will occur, the worst outcome. If actual demand is significantly lower, customers could be said to have paid too much. Those operating the capacity markets are speculating on future supply and demand just as integrated resource planners in vertically-integrated utilities are speculating. *Both are engaging in an administrative planning exercise*.

So, let's not pretend capacity markets, with their administratively set demand curves and scarcity prices, are true markets that are more efficient at predicting the future because of the Hayekian collective intelligence of the marketplace. They are just another way to transfer money from consumers to generation investors to try to ensure sufficient power supply in the future. Not that there's anything wrong with that *in concept*. If Americans are not willing to live with regular power supply shortages – and we are not – then it is necessary to pay in advance for resources to make sure they are there whenever needed, just like buying an insurance policy

62. Naureen S. Malik & Mark Chediak, *Texas Regulator Wants to Pay Power Plants to Help Avoid Deadly Blackouts*, BLOOMBERG NEWS, (Jan. 19, 2023, 4:46 PM), https://www.bloomberg.com/news/articles/2023-01-19/texas-regulator-backs-plan-to-pay-power-plants-to-bolster-grid#xj4y7vzkg. Even Texas now appears to be moving away from that approach, although at this writing state elected leaders had not taken final action on such proposals.

63. *About Us*, SW. POWER POOL, INC., https://www.spp.org/about-us/.

64. *Capacity Market (RPM)*, *supra* note 57 ("Capacity represents a commitment of resources *to deliver when needed*, *particularly in case of a grid emergency*." (emphasis added)).

that may never be used. Just don't pretend, however, that what's at work in capacity markets is Adam Smith's invisible hand efficiently allocating capital through a single-clearing price mechanism.

And that raises the following question: How can this administrative pricing mechanism used in capacity markets -- with the complexities and subjectivity of an administratively set demand curve, administratively set local deliverability areas used to calculate zonal prices to load, administrative determination of CONE, administrative judgments about effective load carrying capabilities, offer caps, *etc*. -- possibly be described as the "market" alternative to the "regulated" construct of paying for needed generation through rate base, or purchasing needed power through bilateral contracts? To the honest observer RTO capacity markets and state IRP processes are *both* planning constructs, just in different forms. This article suggests that most state IRP processes may be far better suited to plan comprehensively, to manage the risks associated with different types of generation, to incorporate demand-side resources, and to balance state policies promoting renewables with the core goals of delivering reliability and controlling consumer costs than RTO capacity markets are.

VII. DO SINGLE-CLEARING PRICE THEORIES FIT THE PRESENT-DAY REALITIES OF RTO POWER MARKETS?

To consider whether the theories offered in support of SCP mechanisms still apply, return to Justice Kagan's elegant description in *FERC v. EPSA* of how SCP works in U.S. power markets:

> So, for example, suppose that at 9 a.m. on August 15 four plants serving Washington, D. C. can each produce some amount of electricity for, respectively, $10/unit, $20/unit, $30/unit, and $40/unit. And suppose that LSEs' demand at that time and place is met after the operator accepts the three cheapest bids. The first three generators would then all receive $30/unit. That amount is (think back to Econ 101) the *marginal* cost—i.e., the added cost of meeting another unit of demand—*which is the price an efficient market would produce*.[65]

As Justice Kagan remembered from her Econ 101 class, the *marginal cost would be the price an efficient market would produce.* That, then, is the very foundation of the theory for using a single-clearing price mechanism, that the *marginal* cost is the price an *efficient market* would produce. The entire edifice of the SCP mechanism is based on this textbook theory of efficient markets.

But what if RTO markets are *not* efficient markets? In fact, as discussed above, what if they are not even markets at all? If the theory justifying the use of single-clearing price mechanisms is contrary to reality, savvy bettors know that in the clash between theory and reality, bet on reality to win. So, let's explore the theories versus the realities of the RTO markets in which single-clearing price mechanisms are being used.

The first theory, as Justice Kagan posited, is that in RTO markets competition is taking place on a level playing field *at the margin*, with generators competing on their *marginal* costs of production.[66] This theory comes closest to reality in the

65. *Elec. Power Supply Ass'n*, 577 U.S. at 268 (emphases added).

66. *Id.*

real-time markets, which are supposed to be agnostic as to the source of the power and which use the granular LMP mechanism to set prices at a nodal level every five minutes. Yet even in real-time energy markets the efficient-market theory is flawed, since some resources are almost always going to clear both because they effectively have *no* marginal costs (although significant upfront capital costs)[67] as well as heavy federal and state subsidies that may allow them to offer at a price of zero or even below. Both these factors give renewables a significant advantage over competitors that have significant marginal costs (but may have lower capital costs).[68]

Typically, the marginal cost for dispatchable[69] generation consists largely of the cost of fuel. But because several common types of dispatchable "baseload" generation, such as combined-cycle gas, nuclear[70] and coal, run most efficiently on a continuous basis for long periods, these generators are more cost-effective and therefore more competitive when priced on an average-cost basis, not on marginal costs. By contrast, intermittent resources,[71] including wind and solar, have no fuel costs at all, an overwhelming advantage when RTO markets determine winners purely on the short-term marginal cost of production.

This reality means that when RTO markets clear based on marginal costs, generators with virtually no marginal costs and subsidies that enable offers at zero

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67. Michael Milligan et al., *Marginal Cost Pricing in a World without Perfect Competition: Implications for Electricity Markets with High Shares of Low Marginal Cost Resources*, NAT'L RENEWABLE ENERGY LAB'Y 27 (2017), https://www.nrel.gov/docs/fy18osti/69076.pdf ("[Wind and solar] generation resources have high capital costs with near-zero marginal costs because of the lack of fuel costs.").

68. Clark & Duane, *supra* note 5, at 3-6.

69. Dispatchable generation is on-demand generation that (i) is not weather-dependent, (ii) can be scheduled with reasonable certainty, and (iii) can run for extended periods. *Energy Education: Dispatchable Sources of Electricity*, UNIV. OF CALGARY, https://energyeducation.ca/encyclopedia/Dispatchable_source_of_electricity#:~:text=A%20dispatchable%20source%20of%20electricity,the%20electrical%20grid%20on%20demand. Dispatchable generators are not impervious to weather extremes – Arctic weather can impact natural gas supply and degrade the performance of gas generators, as happened during both Winter Storms Uri in 2021 and Elliott in 2022– but dispatchable generators are not literally dependent on certain weather conditions to produce power, as intermittent resources are. *Infra* note 71.

70. Nuclear units have extraordinarily high capital costs but are designed to run continuously for months and refuel on a schedule independent of each dispatch. *U.S. nuclear capacity outages were 35% higher in summer 2020 than 2019*, U.S. ENERGY INFO. ADMIN. (Sept. 18, 2020), https://www.eia.gov/todayinenergy/detail.php?id=45176. "A planned nuclear generation outage is usually scheduled to coincide with a plant's refueling cycle. U.S. nuclear power plants typically refuel every 18 to 24 months . . . ." *Id*.

71. Intermittent resources are dependent on specific weather conditions to produce power. *Intermittent Power Resources: Frequently Asked Questions*, NEW YORK ISO, https://www.nyiso.com/documents/20142/20259596/Intermittent-Power-Resources-FAQ.pdf/110f029a-2864-cf0d-9f64-54d2edc12913; *Energy Education: Dispatchable Sources of Electricity*, *supra* note 69. The wind must blow for wind generators to produce and the sun must shine for solar generators to produce, which means that intermittent power production rises and falls independently of, and without correlation to, the demand for power (a/k/a "load"). While weather can be *forecasted* with varying degrees of accuracy, weather cannot be *scheduled*, so weather-dependent generators cannot be scheduled with certainty beyond the period weather itself can be accurately forecasted – and, of course, even next-day weather forecasts can be wrong. Battery storage has the potential to change this engineering reality if or (hopefully) when long-duration batteries are developed that can store enough power to inject on demand hundreds of megawatts into the grid for several days at a time, not just a few hours, and at costs that are competitive with other resources.

or below start with a huge built-in advantage. The single-clearing price mechanism makes that advantage even more profitable, because these generators can offer in at zero or below with out-of-market subsidies, but then receive the highest clearing price anyway, set by the last generator that is necessary to meet the demand curve, often a high-cost gas combustion turbine "peaker." This dynamic leads to another serious problem with incentives in current RTO market design: Investment in dispatchable generation that can no longer compete against heavily-subsidized, no-marginal-cost competitors will dry up, because what investor wants to risk capital on a generation resource that will face a market pricing mechanism stacked against it? This means existing dispatchable units necessary to keep the lights on will retire early and few new ones will be planned, as the current interconnection queues in RTOs already reflect. These consequences threaten reliability, as the North American Electricity Reliability Corporation (NERC) and the RTOs themselves continue to warn us.[72]

A second theory offered to support the use of a single-clearing price mechanism is that it sends price signals that balance *both* supply and demand. Advocates describe the SCP mechanism of LMP as delivering efficiency *both* on the supply and the demand side and emphasize the importance of scarcity pricing as part of the utility specifically of LMP:

> The description of the real-time LMP model often simplifies to marginal-cost pricing, which then collapsed to the treatment of the marginal cost of generators. In part this derives from *assuming that demand was fixed*. But this descriptive convenience was never exactly correct, nor necessary. For example, when load reached the capacity of a given swath of generation, there would always be an additional price component that would reflect the scarcity of lower cost generation. That would include high load periods when *all the available generation capacity was in use*. *Then scarcity prices would be necessary to balance supply and demand.*[73]

This last passage is particularly revealing. The use of single-clearing price mechanisms – LMP in this reference -- in American power markets is not only about giving price signals to generators and rewarding those with the lowest marginal costs. SCP is also justified as essential on the *demand* side, by using scarcity pricing to signal to load to *reduce demand* when supply is extremely short, in order to avoid the catastrophic imbalances between supply and demand experienced, for example, in ERCOT during Uri.

So, this argument for the single-clearing price mechanism is its value as a price signal *both to supply and demand*. But that seems suspect on both ends.

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72. Robert Walton, *Most of US electric grid faces risk of resource shortfall through 2027, NERC finds*," UTILITY DIVE (Dec. 16, 2022), https://www.utilitydive.com/news/nerc-grid-resource-adequacy-shortfall-reliability-assessment/638949/ ("NERC has been warning about the speed of the energy transition in recent years. 'Just to say it for the fourth or fifth time: Managing the pace of our generation retirements and our resource changes to ensure we have enough energy and essential services is an absolute necessity,' [NERC spokesman John] Moura said."); *see also* PJM, ENERGY TRANSITION IN PJM: RESOURCE RETIREMENTS, REPLACEMENTS AND RISKS (2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx (showing almost 40 gigawatts of largely dispatchable coal and gas generation resources predicted to retire in the next few years and insufficient replacement capacity in the queue).

73. Hogan, *supra* note 7 (emphases added).

For what if out-of-market subsidies have utterly distorted the price signals to supply resources, even occasionally distorting price signals and producing unfair outcomes among zero-marginal cost renewable resources themselves, such as state subsidies that may favor offshore wind to the detriment of onshore wind or solar?

And, on the demand side, the price signals to load are, *and always have been*, submerged in a *retail* power bill consisting of numerous non-by-passable charges, including separate, large and rapidly growing charges for distribution and transmission services, not to mention an array of out-of-market payments that appear as bill riders for zero-emission credits (ZECs), renewable energy credits (RECs), reliability-must-run (RMR) payments to generators, percentage of income wealth transfers, or any of the myriad other bill riders that special interests have lobbied state legislatures to authorize?[74]

Indeed, retail electric bills, even in fully deregulated states, have never reflected the nodal, five-minute changes in LMPs, and thus the claim that scarcity pricing based on LMPs is essential to balance supply and demand, especially at times when there is no more generation to dispatch (as in ERCOT during Uri), appears utterly disconnected from the reality of retail regulation at the state level. For it is state-level retail rate regulation that establishes the actual price signals that load – residential, commercial and industrial consumers – are effectively receiving. While some large industrial customers have responded to wholesale price changes through curtailment programs that pay them to reduce load, the vast majority of retail customers are not responsive to continual changes in wholesale costs since retail rates are fixed. On its face, that means retail residential customers cannot respond to wholesale power price changes. It is obvious then that retail customers, especially residential, are simply not going to respond to any single-clearing price mechanism in wholesale power markets by reducing their demand in five-minute or any other increments. That means depending on LMP or any single-clearing price mechanism in RTO markets to balance supply and demand in times of emergency is disconnected from reality.[75]

A third theory for the use of single-clearing price mechanisms in RTO markets holds that electricity is a *commodity*, so sellers can only compete on price and efficiency of production, not on differential attributes. This theory assumes all electrons are identical, so the price should be the same for all offers necessary to clear the supply stack. Following Justice Kagan's efficient-market theory of marginal costs, that means the highest clearing price should go to *all* sellers, even those who offered at zero or lower.

This theory also breaks down in the real world. RTO markets are not a forum for selling and buying physical power only on an agnostic basis, but rather, for

74. Clark & Duane, *supra* note 5, at 6-8.

75. The author has long been an advocate of variable or dynamic retail rate designs, such as time-of-use pricing, to send retail customers much more accurate price signals about the real-time cost of their power, but those retail rate design issues are matters of state regulatory authority, not federally-regulated RTO wholesale markets. Further, for time-of-use rate designs to be effective they require the wide deployment of costly advanced metering infrastructure, known as "smart meters." And such rate designs require a major effort to re-educate customers who for decades have been used to rates that are the same whenever power is being consumed.

buying and selling various packages of services -- real-time power, day-ahead financial hedging, financial transmission rights, ancillary services, future capacity deliverability. Indeed, RTO markets themselves have long undercut this commodity theory of electrical power through the use of devices such as "uplift" (a form of supplemental, out-of-market payment for certain necessary attributes)[76] and extended load carrying capability (ELCC) criteria, which adjust the accredited value of resources offered in capacity markets based on their assumed ability to perform at peak or emergency times. So, any pricing model based on a theory of the fungibility of electrons has long been compromised by the variety and differentiated characteristics of the products traded in RTO markets.

Even more importantly, the *political* reality is that certain state and federal policies, which create the context in which RTO markets operate, no longer treat electricity as a commodity at all. On the contrary, certain policies now regard the *source* of the power as far more important than the *price* of the power. Again, history provides relevant context. When RTOs and their markets were set up under Order No. 2000, the states joining RTOs to participate in those markets – as well as Congress and FERC – all generally shared a goal of obtaining power from any generator that represented the most efficient and least cost to consumers.[77]

Over the past two decades, however, that expectation has changed radically. Roughly half of the states adopted mandatory renewable portfolio standards (RPS) that explicitly favor renewable generation resources, primarily wind and solar, over thermal resources such as coal and gas.[78] A mandatory RPS is typically characterized by a legal requirement that load-serving utilities in the state must procure and sell to their customers a minimum but continually increasing percentage of power from renewable resources.[79] Obviously, a state law that mandates the purchase of certain preferred generation resources, but not their competitors, is in direct conflict with the principle of markets agnostically choosing winners based on price and efficiency.[80]

Further, at the federal level, Congress has enacted a whole array of subsidies in the form of investment and production tax credits. The recently passed "Inflation Reduction Act of 2022" increased the monetary values and lengthened the time periods for using the various subsidies available to preferred competitors in

76. Clark & Duane, *supra* note 5, at 3.

77. For example, the Energy Policy Act of 2005 provided a definition of the policy goal of "economic dispatch" as "the operation of generation facilities to produce energy at the *lowest cost to reliably serve consumers*, recognizing any operational limits of generation and transmission facilities." Energy Policy Act, 42 U.S.C. § 16432(b) (2005) (emphasis added).

78. *State Renewable Portfolio Standards and Goals,* NAT'L CONF. STATE LEGISLATURES (Aug. 13, 2021), https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx. Several additional states have voluntary or aspirational goals; some others have repealed or allowed mandatory standards to expire. *Id.*

79. Nancy Radar & Scott Hempling, THE RENEWABLES PORTFOLIO STANDARD A PRACTICAL GUIDE*,* U.S. DEP'T OF ENERGY (2001), https://www.energy.gov/oe/articles/renewables-portfolio-standard-renewables-portfolio-standard.

80. Implementing a state RPS is actually more practicable in a vertically integrated, cost-of-service regulatory model, in which state regulators can direct their state's utilities to meet the RPS goals through an integrated resource planning process which balances all resources – transmission, generation, demand-side – while maintaining reliability.

RTO markets, such as wind and solar generators, but these subsidies were not made available to other competitors, such as gas and coal generators.[81] These federal subsidies effectively pick winners and losers in RTO markets.[82]

Thus continuing to use single-clearing price mechanisms in power markets produces a windfall (no pun intended) for the policy-preferred intermittent resources, which can offer at zero or below but receive the highest clearing price. So while the theory of RTO markets two decades ago may have born some resemblance to Justice Kagan's efficient-market theory from Econ 101, the reality today is that the wide array of state and federal subsidies has created a chasm between the RTO administrative constructs called "markets" and true markets in which competitors operate on a level playing field.

As a result, it is appropriate to consider whether single-clearing price mechanisms can still produce just and reasonable rates, which is, after all, what the Federal Power Act requires.[83] Do SCP mechanisms really produce benefits for consumers that are worth the costs? These questions are especially serious in capacity markets but should be examined in the context of all RTO markets. The deregulation tide that washed single-clearing price mechanisms into RTO markets has receded, and to paraphrase Warren Buffett, "when the tide goes out, you find out who's been swimming naked."[84]

So let's turn to a discussion of possible alternatives to single-clearing price mechanisms across different types of RTO markets.

VIII. ALTERNATIVES TO SINGLE-CLEARING PRICE MECHANISMS IN REAL-TIME AND DAY-AHEAD MARKETS

As noted above, real-time energy markets are what Justice Kagan was describing in her opinion in *FERC v. EPSA*. The arguments offered by Professor

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81. Nicholas James Irmen et al., *Inflation Reduction Act: Implications for Solar and Wind Tax Credit Equity Markets*, NAT'L L. REV. (Sept. 1, 2022), https://www.natlawreview.com/article/inflation-reduction-act-implications-solar-and-wind-tax-credit-equity-markets. *See* Adam Schurle et al., *The Inflation Reduction Act: Key Provisions Regarding the ITC and PTC,* RENEWABLE ENERGY OUTLOOK (Aug. 12, 2022), https://www.foley.com/en/insights/publications/2022/08/inflation-reduction-act-key-provisions-itc-ptc.

82. Katherine Nelson & Steve Piper, "Inflation Reduction Act-led decarbonization and the future of fossil generation," S&P GLOB. CAP. IQ (Dec. 19, 2022) ("The Inflation Reduction Act of 2022 creates tailwinds for green energy that put corresponding pressure on coal and natural gas generation. S&P Global Market Intelligence Power Forecast *predicts 117 GW of fossil generation will retire, with coal plants accounting for 70% of this capacity. Just as importantly, little new gas generation is forecast*, as storage undercuts gas capacity value and renewable generation undercuts gas in merit dispatch. . . . *Green energy incentivized by the act is poised to undercut project-financed merchant generation as we have understood it over the past 20 years*."). (emphases added)). It is deeply ironic given the history of federal energy policy since the Clinton administration, which has pushed competition in RTO markets as superior to state-regulated cost-of-service models, that these federal subsidies both undercut the competitiveness of RTO markets at the same time they make the state cost-of-service models much more attractive for fully utilizing these subsidies.

83. 16 U.S.C. § 824.

84. *Swimming Naked When the Tides Goes Out*, MONEY, (Apr. 2, 2009), https://money.com/swimming-naked-when-the-tide-goes-out/. The author has heard this quote also attributed to former Federal Reserve Board Chairman Paul Volcker, who served from 1979-1987. Buffett may have said it, but Volcker proved it when he relentlessly raised interest rates to squeeze out the double-digit inflation of the 1970s.

Hogan and others advocating the use of an SCP mechanism – specifically LMP – are most persuasive when applied to real-time energy markets.

Operated by all RTOs, they are the simplest constructs and most closely resemble real markets. Real-time energy markets enable the buying and selling of a *physical* product, the electrical power itself.[85] All use LMP as their single-clearing-price mechanism. In RTOs, however, only about 5% of load is scheduled in real-time markets; 95% is scheduled in day-ahead markets.[86]

Day-ahead markets, which are operated by most RTOs,[87] enable trading in a *financial* product, a contract setting a price on power to be delivered the next day.[88] The day-ahead markets also enable the system operators to schedule power generation commitments on an hourly basis, as well as ancillary services,[89] the day *before* what is called the "operating day." System operators use the real-time markets to balance supply with actual load.[90] Like real-time energy markets, RTO day-ahead markets use LMP as their single-clearing price mechanism. On the operating day, even if real-time LMP is higher than the agreed-upon day-ahead price, the buyer of the day-ahead contract pays no more than the contract price.

In the RTO real-time and day-ahead markets, one obvious alternative to any single-clearing price mechanism is simply to allow buyers and sellers to agree upon a mutually agreeable price for each transaction, just like in real markets. Consumers would benefit from paying the prices offered *below* the highest clearing price, instead of paying the highest clearing price to all sell offers, as happens now in those markets.

This simple pricing mechanism is already what takes place in bilateral trading markets, which operate in both RTO and non-RTO regions,[91] either in real-time trading or through power purchase agreements (PPAs). Willing buyers and willing sellers agree on the price for each transaction, as they have for decades. That is what power pools were originally established to do, to facilitate bilateral power trades between utilities, first to provide power to avoid outages during emergencies, then more generally to facilitate cost-savings by sharing reserve generating capacity.[92]

It is important to emphasize that bilateral trading can be just as competitive, even more so, than in market constructs, so it is wrong to assume that a bilateral

85. ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS, *supra* note 18, at 127.

86. *Id.* at 62-64.

87. The California Independent System Operator (CAISO) does not currently operate a day-ahead market, but is developing one. *Initiative: Extended Day-Ahead Market (EDAM),* CAISO, https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Extended-day-ahead-market.

88. ENERGY PRIMER: A HANDBOOK OF ENERGY MARKET BASICS, *supra* note 18, at 62-64.

89. Ancillary services are "functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load." *Id.* at 77. Ancillary services can include reserves that have different ramping time attributes, from a few minutes to as much as thirty minutes, and include spinning reserves, non-spinning reserves and supplemental reserves. *Id.* at 56-57, 88.

90. *Id.* at 1.

91. *Id.* at 58-59. It should be noted that some bilateral transactions in both RTOs and non-RTOs are based on cost-based, not market-based, rates.

92. *Id.* at 36-37.

trading system is somehow an abandonment of competition.[93] In both RTO and non-RTO states these transactions should still remain subject to FERC's duty (i) to protect consumers from exercises of market power, (ii) to grant or deny market-based rate authority and (iii) to punish bad actors who manipulate bilateral trading or engage in predatory pricing.

Nor should it be assumed that bilateral trading between utilities can only be conducted in the traditional and time-consuming way, such as by telephone calls. Bilateral trading systems are subject to continual improvements based on technology and can be set up to operate in real time, just as RTO markets do. For example, the Southeast Energy Exchange Market (SEEM) is already operating a real-time, bilateral, power trading market. This is a fully automated bilateral market operating on a computer algorithm that matches willing buyers and sellers every 15 minutes.[94] There are no transmission costs because only unused transmission capacity is used, so there is no "rate pancaking."[95] A willing buyer and a willing seller set the price for *each* transaction, using a "split the difference" pricing formula that automatically settles each transaction at the mid-point between the offer and bid. No SCP mechanism is used. Prices are localized to the buyer and seller. Price signals are transparent and available.[96]

Another alternative being considered in Europe is to bifurcate the market, establishing different clearing prices for low-marginal cost resources such as wind and solar, and another for gas.[97] This could solve the perceived problem with pay-as-offered, that low marginal cost sellers would simply game the market by offering at or near what they think the clearing price will be anyway, so consumers really save no money.[98]

Yet another option to consider could be some form of average pricing, so that the highest clearing price was not exclusively the price that is paid to all sell offers.

The point is not to advocate a specific alternative, but to ask whether any of these options -- pay as offered, average pricing, automated, real-time bilateral trading, or a market bifurcated between low and high marginal cost generators -- represent better pricing mechanisms than paying the highest clearing price to all

93. Mullin & Downing, *supra* note 44 ("[Robert] McCullough . . . among the first to identify the manipulation that sparked the Western energy crisis of 2000-01 . . . has long been a vocal critic of RTOs and ISOs, which he refers to as 'administered' markets, compared with what he calls the 'competitive' bilateral wholesale markets that predominate in the West. 'Northwest power markets are large and competitive and low-price, but we don't have a central administrator to tell us what to do.'").

94. SE. ENERGY EXCH. MKT., https://southeastenergymarket.com/.

95. *Pancaking*, HARVARD ELEC. POLICY GRP., https://hepg.hks.harvard.edu/faq/pancaking ("Rate pancaking" means paying multiple charges to more than one utility to move electric power across multiple utility systems.).

96. *Regulatory Filings and Documents*, SE. ENERGY EXCH. MKT., https://southeastenergymarket.com/filings/.

97. India already operates bifurcated markets separating renewables from other generating resources. *See supra*, note 3.

98. *Action and measures on energy prices*, *supra* note 3 ("In the pay-as-bid model, producers (including cheap renewables) would simply bid at the price they expect the market to clear, not at zero or at their generation costs.").

sellers.[99] No one should prejudge the answers, but those are the types of questions that should be explored, without limitation, in a cautious and thorough reconsideration of pricing mechanisms in US real-time and day-ahead power markets.

IX. CAPACITY MARKETS AND ALTERNATIVES

"I've always viewed forward capacity markets as the original sin of market design."

– Professor William Hogan[100]

When one of the leading theorists of power-markets rate design pronounces capacity markets a sin, it is obviously time to ask whether capacity markets themselves are an experiment that is no longer working as intended, if it ever did, regardless of the pricing mechanism.

As noted above, U.S. capacity markets use a single-clearing price mechanism, but not LMP, so the arguments in favor of LMP's granularity do not apply.[101] Capacity markets do not enable the purchase and sale of physical power, but rather a *promise* to deliver power (or to reduce load, which promise does not represent a generating resource) at a *future* point in time to meet a predicted peak demand. The transactions involve essentially futures contracts. Price signals do not reflect real-time power sales, but only the trading in what Professor Hogan below calls "financial hedging contracts."[102]

Again, as briefly referenced above, the argument that all electrons are fungible, that power is a commodity, and therefore that all promises to deliver power in the future should be priced at the *highest* clearing price, simply evaporates in application to capacity markets. State policies mandating that utilities must purchase

99. At least one RTO implicitly acknowledged concerns with LMP and did try to develop an alternative. PJM discussed a proposal for something called an "Integer Relaxation for Electricity Market Clearing" mechanism. Clark & Duane, *supra* note 5, at 4-5. It ultimately went nowhere.

100. Sam Mintz, *NECA Panelists Talk Capacity Market, DERs*, RTO INSIDER (Dec. 14, 2022), https://www.rtoinsider.com/articles/31291-neca-panelists-talk-capacity-market-ders ("'I know it's politically embedded in the system . . . but *I don't think they're a solution to any real problem other than mailing checks to people,*' Hogan said." (emphasis added)).

101. Harvey and Hogan distinguish the use of LMP in American energy markets with the lack of its use in the UK and EU, which according to the authors use much less granular, and therefore less effective, SCP mechanisms. Harvey & Hogan, *supra* note 7, at 5, 15. Which may be true, but not necessarily dispositive of the question whether paying all offers the marginal price is appropriate. Regardless of the geographic scope of the "L" in Locational Marginal Pricing, it is the "M" in LMP that may be the problem, as it is in all single-clearing price mechanisms.

102. Hogan, *supra* note 7, at 23.

power *based on the type of generator* or other attributes, other forms of state subsidies, such as zero emissions credits (ZECs),[103] combined with lavish federal subsidies in the form of investment and production tax credits,[104] undercut any continuing claim that capacity markets are simply procuring the lowest-cost capacity on an agnostic basis. As one former FERC commissioner pungently put it, "Hundreds of billions in favored federal tax treatment and subsidies for renewable[s] . . . is more than a thumb on the scale of energy markets, it is a twelve-ton dump truck."[105] So what purpose is served by giving *all* sell offers the *highest* clearing price? If their promises of future deliverables are based on their *actual* costs, discounted for subsidies, why shouldn't each seller that clears simply get its offer price?

As a result of the "twelve-ton dump truck" on the scale, the large multi-state RTOs such as PJM now contain states with such widely divergent energy policies that trying to operate a credible capacity market on an RTO-wide basis increasingly appears to be a hopeless exercise, as the intense controversy among the states over PJM's most recent minimum offer price rule (MOPR) proposal demonstrates.[106]

Even the strongest advocates of the use of the single-clearing price mechanism of LMP in real-time and day-ahead markets are highly critical of the capacity market construct itself, regardless of the SCP pricing mechanism. As Professor Hogan puts it:

> The problems with forward capacity mechanisms and stimulating investment arise in part because *ensuring specific performance of physical capacity contracts is beyond the capability of our knowledge*. If we knew how to guarantee deliverability of specific generation determined years ahead in capacity auctions, we would not need organized markets to manage the complex conditions that arise in the real-time market.

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103. *NY Creates New Emissions Credit for Nuclear Plants*, McDERMOTT, WILL & EMERY: ENERGY BUSINESS LAW (Sept. 20, 2016), https://www.energybusinesslaw.com/2016/09/articles/environmental/ny-creates-new-emissions-credit-for-nuclear-plants/) ("The ZEC, or zero-emissions credit, is the first emissions credit created exclusively for nuclear power . . . . The ZEC is the result of a highly politicized effort to support New York's struggling nuclear power plants."); *see Zero Emission Credits*, ILL. POWER AGENCY, https://www.ipa-energyrfp.com/zero-emission-credits/ (Illinois also legislated a ZEC subsidy.).

104. Irmen et al., *supra* note 81; Schurle et al., *supra* note 81. *See also* Nelson & Piper, *supra* note 82. This article acknowledges that the federal tax code and budget are riddled with various forms of tax and spending subsidies for a wide range of energy resources, depending on how one defines "subsidies," including some benefitting oil, natural gas and coal. ENV'T AND ENERGY STUDY INST., FOSSIL FUEL SUBSIDIES: A CLOSER LOOK AT TAX BREAKS AND SOCIETAL COSTS (2019), https://www.eesi.org/files/FactSheet_Fossil_Fuel_Subsidies_0719.pdf. Such subsidies do not have the specific and immediate impact on the operation of pricing mechanisms in RTO power markets, however, that the tax subsidies in the Inflation Reduction Act do.

105. Tony Clark*, Inflation Reduction Act adds fuel to RTO reform imperative, generator interconnection backlog*, UTILITY DIVE, (Nov. 8, 2022), https://www.utilitydive.com/news/inflation-reduction-act-ira-rto-interconnection-queue-ferc-tony-clark/635959/. Renewables advocates might argue that thermal resources such as coal and gas have also long received *implicit* subsidies by not being charged for negative externalities such as carbon emissions. The debate over quantifying externalities, which to be serious must consider all externalities, *both* negative and positive, is needed, but is not the subject of this article.

106. See, *e.g., Amended Joint Petition for Rehearing of the Pennsylvania Public Utility Commission and Public Utilities Commission of Ohio to the Commission's Failure to Issue an Order Accepting or Denying PJM's Filing Concerning Application of the Minimum Offer Price Rule*, FERC Docket No. ER21-2582-000 (Aug. 20, 2021).

> Recognizing that capacity mechanisms are in effect *financial hedging contracts* . . . would allow market reforms and the *gradual atrophy of the existing capacity markets*.[107]

Others have likened the continuous effort to "fix" capacity market constructs through seemingly perpetual tweaking and adjusting to an endless "whack-a-mole" game.[108]

So what are the alternatives to the use of SCP in capacity markets? Indeed, to the use of capacity markets at all?

First, it should be asked whether the pure economics "textbook solution" -- scarcity pricing alone -- should be considered an acceptable regulatory method of achieving resource adequacy.[109] "Scarcity pricing" is another term for "shortage pricing," but socially and economically Americans simply cannot and will not accept extended shortages in the power supply. Indeed, multi-day shortages lead to catastrophes such as Texas during Winter Storm Uri, during which skyrocketing scarcity prices did not lead to an immediate influx of power resources entering the market to restore power, but did produce horrific spikes in power bills for load-serving utilities and ultimately retail consumers.

What happened in Uri should not be dismissed as an outlier.[110] While extraordinary weather events can take down any power grid regardless of market design, often through wind or ice impacts on the wires grid, when the outages are caused by loss of power supply depending on scarcity pricing to restore supply quickly is a recipe for turning an already bad situation into a disaster.[111]

Winter Storm Uri illustrates an important lesson. To ensure that sufficient generating reserve capacity is available at all times of peak demand, in order to deliver the level of reliability Americans expect, generating capacity *must* be funded in advance and cannot depend solely on scarcity pricing.

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107. Hogan, *supra* note 7, at 23 (emphases added).

108. Delia Patterson & Harvey Reiter, FERC CHASING THE UNCATCHABLE: TRYING TO FIX MANDATORY CAPACITY MARKETS IS LIKE TRYING TO WIN AT WHACK-A-MOLE, STINSON, LLP (2016), https://www.lexology.com/library/detail.aspx?g=1017dff1-42c8-4b8f-ada1-6ce816a20fec ("FERC's efforts to get capacity markets "right" . . . have instead led to endless - and futile - tinkering. . . . It's time for FERC to start over, or at least regroup and reassess.").

109. Hogan, *supra* note 7, at 17 ("The Texas experience through 2020 reinforced the need for scarcity pricing and the analysis of the benefits. Prices were high during scarcity conditions, helped alleviate stress on the system, and were supporting new generation investment.").

110. *Id.* at 17-18 ("The exceptional emergency during February 2021 remains a subject of important further study and investigation as part of the regulatory review. However, the weather conditions were a one-in-fifty year event, so extreme and well outside the traditional one-in-ten year reliability standard that it is not clear than any electricity system design would have fared well.").

111. Variations on scarcity pricing, such as an operating reserve demand curve (ORDC), which is used by some RTOs (including ERCOT) to procure reserves needed for reliability, look very much like another way to provide the "missing money," serving a capacity market function by another name. *See generally* Raúl Bajo-Buenestado, *Operating reserve demand curve, scarcity pricing and intermittent generation: Lessons from the Texas ERCOT experience*, 149 ENERGY POL'Y 112,057 (2021) ("The basic idea underlying this mechanism is that generators that participate in the real-time market get paid not only the real-time (locational marginal) price, but also an "extra" price –called the ORDC price adder– if total reserves available in the market cross a lower threshold.").

Certainly, capacity markets are one option to pay generation resources to be available, but even assuming the continuance of capacity markets does not mean an unquestioning acceptance of the use of an SCP pricing mechanism in capacity markets. One possible alternative is instead to pay each winning seller the price it offers. Since RTO capacity markets are not using LMP specifically, the arguments for LMP in terms of the granularity of its price signals do not apply in defense of the less granular SCP mechanisms used in capacity markets. Adopting a "pay as offered" mechanism could cut costs to consumers substantially since consumers could get the benefit of the lower-priced offers from heavily subsidized resources such as wind and solar.

There are several other alternatives to the current pricing mechanisms in capacity markets, even to capacity markets themselves. Among them include (i) developing easier and more attractive methods for load-serving utilities in RTOs with capacity markets to self-supply outside of the capacity market, (ii) replacing forward capacity markets with near-term auctions that do not extend beyond the coming year or season,[112] (iii) using capacity markets only as a residual option, as in MISO,[113] or (iv) phasing out capacity markets entirely. Neither SPP -- an RTO -- nor the Western Power Pool's recently formed Western Resource Adequacy Program use capacity markets to achieve resource adequacy; rather, both use a construct that requires load-serving utilities either to build or purchase through bilateral contracts sufficient capacity to keep the lights on.[114]

In the broadest sense, states in the multi-state RTOs that are relying primarily on capacity markets for their utilities' resource adequacy should consider whether to reclaim their responsibility for resource adequacy, and if necessary, to amend their state's regulatory construct for utility regulation to enable such a reclamation of responsibility.

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112. Kate Winston, *US Forward Capacity Markets are a 'Terrible Idea' Should be replaced: Market Monitor*, S&P GLOB. COMMODITY INSIGHTS: MEGAWATT DAILY (Mar. 9, 2023), https://www.spglobal.com/commodityinsights/en/products-services/electric-power/megawatt-daily ("Forward capacity markets do not work, and key regions that have them should consider switching to a prompt capacity market that procures capacity for just the coming year or season . . . . 'Forward capacity markets are a terrible, terrible idea. They have always been a bad idea,' said David Patton, president of Potomac Economics [and independent market monitor for MISO and ISO-NE]").

113. In MISO, even though the capacity market is considered residual or voluntary, questions are being raised about whether that construct is working well and resource adequacy is becoming a major problem as more and more dispatchable units retire prematurely. Peter Behr & Jason Plautz, *Grid monitor warns of U.S. blackouts in 'sobering report'*, ENERGYWIRE (May 19, 2022), https://www.eenews.net/articles/grid-monitor-warns-of-u-s-blackouts-in-sobering-report/. "MISO officials have agreed with NERC's cautions about the strains on the region's power supplies. MISO is facing increased retirements of coal, natural gas and nuclear generation. . . ." *Id. See* Amanda Durish Cook, *MISO Stakeholders Debate Capacity Accreditation, RA*, RTO INSIDER (Mar. 5, 2023) https://www.rtoinsider.com/articles/31748-miso-stakeholders-debate-capacity-accreditation-ra ("[WEC Energy Group's Chris] Plante said the capacity market has evolved from its 'humble beginnings' . . . . MISO and stakeholders should reestablish what they want from their capacity market. . . .").

114. *See Southwest Power Pool*, 164 FERC ¶ 61,092 (2018); *see also Northwest Power Pool*, 182 FERC ¶ 61,063 (2023).

States have always had the authority to determine how to regulate their utilities; it is embedded in their inherent police powers.[115] Instead of depending on capacity markets, they could resume requiring each load-serving utility to obtain sufficient power capacity through a balanced mix of constructing new generation financed through rate base to ensure availability in emergencies, as well as procuring power through competitively-bid PPAs, a good way to meet state renewable power mandates while ensuring that necessary resources do not prematurely retire. States could require their utilities to conduct robust integrated resource planning that evaluates generation resources comprehensively, including those on the distribution grid, along with transmission and demand-side programs, to produce the optimal outcomes that provide consumers with reliable power at the least cost.

There is another compelling principle at issue here that is not unique to utility regulation: accountability in a democratic system. When elected state policy-makers and regulators are clearly responsible for ensuring that their state's load-serving utilities have adequate generation resources at reasonable costs, the people know whom to hold accountable when the lights go out or costs are unreasonable.

X. CONCLUSION

"This is the best bad idea we have . . . ."

– Bryan Cranston (playing the CIA deputy director in the movie Argo (2012)[116]

It is time to reconsider – carefully and cautiously – the use of single-clearing price mechanisms in RTO power markets, especially in capacity markets. Indeed, with regard to the latter, it is time to consider whether capacity markets themselves are capable of doing the job they are expected to do, regardless of pricing mechanism, or should be replaced with alternative means of achieving resource adequacy.

In so doing, it is important to recognize two key realities about the American power industry:

First, Americans will not tolerate the temporary shortages that occur regularly in every true competitive market. So, applying the textbook theories of market economics to the power grid that animated the deregulation movement of the late 1990s and early 2000s (and was cynically exploited by rent-seekers such as Enron and many others since), will not provide consumers with reliable power service at the *least* cost under applicable laws, the policy goal when regulating monopoly providers of a vital public service.

Second, given that the electric power industry remains to a significant extent a network industry and one with extremely high upfront capital costs, it will tend to produce sellers with market power.

115. The history of this regulatory authority rooted in the states' inherent police powers is described in the landmark Supreme Court opinion in *Munn v. Illinois,* 94 U.S. 113, 124-28 (1877) and discussed in Christie, *supra* note 24, at 40:949, 954-56. Such inherent authority is, of course, subject to federal pre-emption where constitutional and exercised by Congress.

116. *A*RGO (Warner Bros. 2012).

Both of these features mean that the power industry should and will be heavily regulated. In choosing regulatory models, it is essential to be honest and admit up front *there is no perfect model of regulation.* All regulation attracts rent seekers and contains the threat of regulatory capture. The search is not for the perfect regulatory model; it does not exist. So, like the CIA deputy director in *Argo,* we are seeking the best bad regulatory option. Cost-of-service regulation of vertically-integrated utilities, the model of choice in most American states for most of the past century, and still widely used, undeniably has its many flaws, but it also has its positive attributes.[117] Now more than two decades after deregulation sought to replace state-regulated cost-of-service models with models using RTOs and their power markets that feature single-clearing price mechanisms, it is clear that there are major flaws in those regulatory models as well.

Honesty also requires admitting that these purportedly "deregulated" models are, in fact, just different regulatory constructs. It has always been a false dichotomy to pose the choice as "markets versus regulation," as deregulation advocates used to do and RTO markets advocates still do.[118] As one of history's most brilliant regulatory economists, Alfred Kahn, once said:

"The two principal institutions of social control in a private enterprise economy are competition and direct regulation. Rarely do we rely on either of these exclusively . . . . The proper object of search, in each instance, is the best possible mixture of the two."[119]

In a true market that's competitive, consumers and efficient sellers win and inefficient sellers lose. A competitive market regulates itself and the market participants don't set the rules. So, the regulator's job is not to regulate a competitive market for outcomes but rather to protect competition from rent-seekers and their lobbyists, and to avoid regulatory capture.

Administrative constructs, however, such as RTO markets, where rent-seeking market participants themselves, as well as other interest groups, play a major role in setting the market rules, are far more vulnerable to rent-seeking than truly competitive markets. Now when these constructs have delivered results that were demonstrably cheaper than power purchased through bilateral contracts or from units in rate base, consumers would have benefitted. This article does not deny that there may have been benefits to consumers at times from RTO markets, compared to alternative regulatory constructs, although one could argue just as persuasively that most cost savings to consumers in RTO markets since 2005 were really the result of the fracking revolution that drove natural gas prices down below $3 per MMBtu by 2021 and benefitted consumers just as much in cost-of-service models through lower costs recovered in fuel-factor and other rate mechanisms.

117. Slocum, *supra* note 23, at 2 ("Although [the pre-restructuring state-regulated system] was often abused because of the enormous political power of the electric utilities and their ability to influence state policymakers, it was regarded as *the most reliable and affordable electric system in the world*.") (emphasis added).

118. Peter Eavis, *Clean Energy Quest Pits Google Against Utilities*, N.Y. TIMES (Dec. 20, 2022), https://www.nytimes.com/2022/12/20/business/google-clean-energy.html ("Google says its goals for carbon-free power are impeded by state-regulated utilities, particularly in the Southeast, that lack a competitive market.").

119. Kelliher, *supra* note 23, at 9 (quoting Kahn, *supra* note 17, at xiii).

And while consumers may have benefitted when these markets produced competitive results at a time of falling gas prices, all too often the special interests that did not get what they wanted from RTO markets went to the politicians in the various states and Congress and lobbied for subsidies, portfolio mandates and other forms of rents. It is hard to argue that RTOs have been more immune from the rent-seeking that too frequently takes place in state legislatures;[120] indeed, RTOs are also vulnerable to it, partly due to governance issues that are not the subject of this article.[121] One argument offered for deregulation at its beginning was that the iron discipline imposed by regional markets would block the rent-seeking inherent in the highly regulated state models. It has become clear, however, that deregulation only expanded the rent-seeking opportunities to the RTO constructs and created even more work for special-interest lobbyists pushing state legislatures and Congress to override or negate the competitive results the RTO markets did manage to produce.[122]

So it is now time for a thorough reconsideration of the pricing mechanisms used in all of our RTO power markets. FERC, as the creator and regulator of RTOs and their markets, should lead it. These pricing mechanisms are part of the legacy of deregulation, and a thorough reconsideration should logically examine whether the assumptions that underpinned deregulation are still valid, if they ever were. This reconsideration should begin with capacity markets and should not be afraid to take on the broader question of whether capacity markets can consistently obtain the power supply necessary to maintain reliability at just and reasonable rates, regardless of pricing mechanism.

While not advocating for any specific outcome, this article asserts that undertaking such a comprehensive reconsideration is both timely and compelling. And the focus should always be on the most important questions of all: whether the power industry's customers – residential, commercial and industrial – are really benefitting from these pricing mechanisms in power markets, or whether alternatives would deliver a more reliable power system at lower costs to consumers.

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120. Slocum, *supra* note 23, at 4.

121. On the current problems with RTO governance, while the author may not agree with their ultimate recommendations, Clark and Duane again offer a penetrating insight from expertise and experience. *See* Vince Duane & Tony Clark, WHO OWNS THE RTO?: WHY RTO GOVERNANCE IS AN ACHILLES HEEL IN THE CLEAN GRID TRANSITION, WILKINSON, BARKER, KNAUER, LLP (2021), https://www.wbklaw.com/news/white-paper-who-owns-the-rto/.

122. Slocum, *supra* note 23, at 4; Borenstein & Bushnell, *supra* note 56.

Appendix 7

MONTHLY AUDIT REPORT ON THE SOUTHEAST ENERGY EXCHANGE MARKET

August 2023

Prepared by:

POTOMAC ECONOMICS

Independent Market Auditor

September 29, 2023

I. Overview

This is the Auditor report for the month of August 2023 on the Southeast Energy Exchange Market (SEEM). SEEM is a regional energy market that uses a centralized intra-hour energy exchange to create bilateral trades among its trading participants. It has operated since November 2022 when the initial 18 members began trading. SEEM expanded in late June to include six new members: Seminole Electric Cooperative; Tampa Electric Company; Duke Energy Florida; Florida Power Corporation; TEA Gainesville Regional Utilities; and TEA JEA.[1] August is the second full month of participation by these new members. Trading volumes increased from 71,000 MWh in July to 86,000 MWh in August. The August trading volumes were substantially above the market-to-date monthly average of 48,000 MWh. This is expected given most months in the MktTD average are from when the footprint was smaller. SEEM relies on individual transmission segments connecting each member to evaluate and clear trades, including trades spanning multiple segments. Transmission availability on individual segments varied widely. For many segments capacity is available in every interval. For other segments, availability is zero in many intervals. Considering all intervals and segments, eight percent of the time availability was zero. Due to transmission constraints, transmission loss costs, and participant-specific constraints, about 4,000 MWh of potential economic exchanges were left uncleared in August. As explained herein, these are uncleared offers and bids in the same interval where the offer price was less than the bid price by more than the average cost of losses.

SEEM is an automated market accepts bids and offers from the SEEM members and clears individual bilateral trades every 15 minutes using available transmission capability (ATC) of the SEEM members under a transmission service designed for SEEM called Non-Firm Energy Exchange Transmission Service (NFEETS). The trades are cleared to maximize the trading benefit among all participants. The 15-minute trading extends the prevailing hour-ahead bilateral trading in the region and allows for fuller utilization of the transmission system.

SEEM is governed by the SEEM Membership Board. The automated architecture of SEEM was developed and is operated by Hartigen and who also serves as the SEEM Administrator. Our auditing role is directed by the Membership Board in accordance with elements specified in the Market Rules as developed by the Membership Board and approved by the Federal Energy Regulatory Commission (FERC). The results of our auditing are reported to the Membership Board through submission of this Monthly Report. We also have a duty under the Market Rules to

[1] The market opened in November 2022 with 18 members: Alabama Power Company; Georgia Power Company; Mississippi Power Company; Associated Electric Cooperative, Inc.; Dalton Utilities; Dominion Energy South Carolina, Inc.; Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Louisville Gas & Electric Company and Kentucky Utilities Company; North Carolina Municipal Power Agency Number 1; PowerSouth Energy Cooperative; North Carolina Electric Membership Corporation; Tennessee Valley Authority; Georgia System Operations Corporation; Georgia Transmission Corporation; Municipal Electric Authority of Georgia; Oglethorpe Power Corporation; and South Carolina Public Service Authority.

respond to inquiries made by regulators and other oversight authorities, including FERC. We received no such inquiries during the period of this report.

The SEEM auditing framework is based on the provisions of the SEEM Market Rules Section VI.D. (Auditing Process). These duties are in four main categories. The first duty is to analyze SEEM input, constraints, and matching results to determine if SEEM operates in accordance with the SEEM Rules (SEEM Rules Sections VI.D.1, VI.D.1.4). This is the main day-to-day auditing work and represents most of the activities reported herein.

A second auditing responsibility is ensuring participants have access to SEEM data in accordance with the SEEM Rules (Sections VI.D.2). Access to SEEM data involves allowing each SEEM participant to review its own bids and offers and to view matches made by the system. We are in receipt of the bid and offer data and have verified that this data is available daily.

A third area of responsibility is to report to the Membership Board regarding (1) the reliability and accuracy of the SEEM System, and (2) any complaints received from a Participant to the Membership Board and to investigate further any such complaint at the Board's direction (SEEM Rules Sections VI.D.3, VI.D.1.5). Section II of this report fulfils our duty to report on the reliability and accuracy of the SEEM system to the Board. Regarding reporting on complaints from participants, we did not receive any during the period of this report.

Finally, we have the duty to respond to written questions from Participants, FERC, NERC, state commissions in the region, Tennessee Valley Authority's Inspector General, and any other applicable regulators that oversee the electric operations of any Member regarding the integrity of the matching process (SEEM Rules Sections VI.D.6). We responded to a single request for clarification on transmission path names.

In the remainder of the report (Section II), we provide the results of our analysis of the first main area of responsibility: to analyze of input, constraints, and matching results to determine whether SEEM operates in accordance with the SEEM Rules. This is in two main parts. First, we review various daily screens that ensure specific inputs, constraints, and energy exchanges have met certain validation metrics. Second, we review the economic activity in SEEM to provide insight into its functioning and performance.

II. Auditing Results

In this section, we discuss the results of our monthly auditing. In subsection A, we show the results of our daily screening. In subsection B, we present an overview of the economic activity.

A. Market Operation Screens

We calculate screens, metrics, and other analyses on a daily basis using market data and other data to meet the auditing obligations in the Market Rules. The screens and metrics are developed in accordance with specific Market Rules requirements and are divided into three main categories:

- Verification of bid/offer parameters;
- Evaluation of SEEM matching; and
- Verification of SEEM System Constraints.

The following three subsections describe the screens used for our auditing. Unless otherwise indicated, these screens are calculated daily for all fifteen-minute intervals.

1. Bid/Offer Parameters

The following screens audit the information provided in participant bids and offers.

- Offers (bids) from a participant must have Participant-Specific Constraints identifying at least three other non-affiliated Participants that can be matched as counterparties;
- All offers and bids properly must include a source or sink;
- Each offer and bid must a delivery interval;
- Bids and offers must be 4 MW increments;
- “All or Nothing Selection” must be indicated; and
- The Network Map must be accurate (monthly).

2. Matching

The following screens are used to audit the SEEM matches:

- Match price must not exceed the bid price and must be greater than the offer price;
- Buyer and seller must be distinct participants;
- Participant-specific constraints must be check for any changes (monthly);
- SEEM benefit calculation must be verified;
- Any maximum offer price declared must bind the transaction; and
- Each match must have a NERC Tag.

3. Constraints

The following screens audit the SEEM constraints.

- Transaction volume must not exceed offer or bid volume;
- The SEEM algorithm must only make energy exchanges that yield positive benefits to both buyer and seller; and
- Transaction volume over each segment must not exceed the segment ATC.

We have data transfer and storage architecture in place to receive data from the SEEM market to support the calculation of these screens. With the exception of screening the Network Map and the participant-specific constraints, the screens are calculated daily, and we have developed data processing procedures for each of the daily screens. We applied the screens to the August SEEM data and found that in all intervals the screens have indicated that requirements have been met.

For the monthly audit of the system map, we use the initial map developed by Hartigen and the SEEM working groups as a basis for comparing subsequent maps. This map is an electronic file of all sources, sinks, balancing areas, and SEEM transmission segments that comprise the SEEM system. A SEEM segment is an interface between two balancing areas and in many cases is synonymous with the path used by the system. In some cases, the segments are linked together to allow SEEM matches across multiple systems, forming a multi-segment path. The SEEM model allows any number of SEEM segments to be linked in order to find a beneficial trade.

By using this initial map as a basis of comparison, we will take advantage of the lengthy technical process used by SEEM and the SEEM members to develop the map and assume it is accurate. It would not be practicable to replicate this initial map. The SEEM model uses a static path configuration database to retrieve possible paths associated with the sources and sinks offered and bid in each interval. We saved a snapshot of this database and compared it to the path configuration database used at the start of each month. We identify and evaluate any changes. We found no changes in August and therefore we conclude the network map is accurate for the current sources and sinks participating in SEEM.

In a similar fashion, we evaluate changes to participant-specific constraints. These are counterparties and balancing areas acceptable to each participant for trades in SEEM, as well as any maximum price constraints. In each interval SEEM uses a set of participant-specific constraints for all participant bids and offers. We check each participant for any excluded sellers or buyers and any max price constraints and identify any constraints that changed during the month. There were a small number of changes to these constraints involving two entities expanding their counterparties to recently-added Florida members. No participants changed any maximum price constraints.

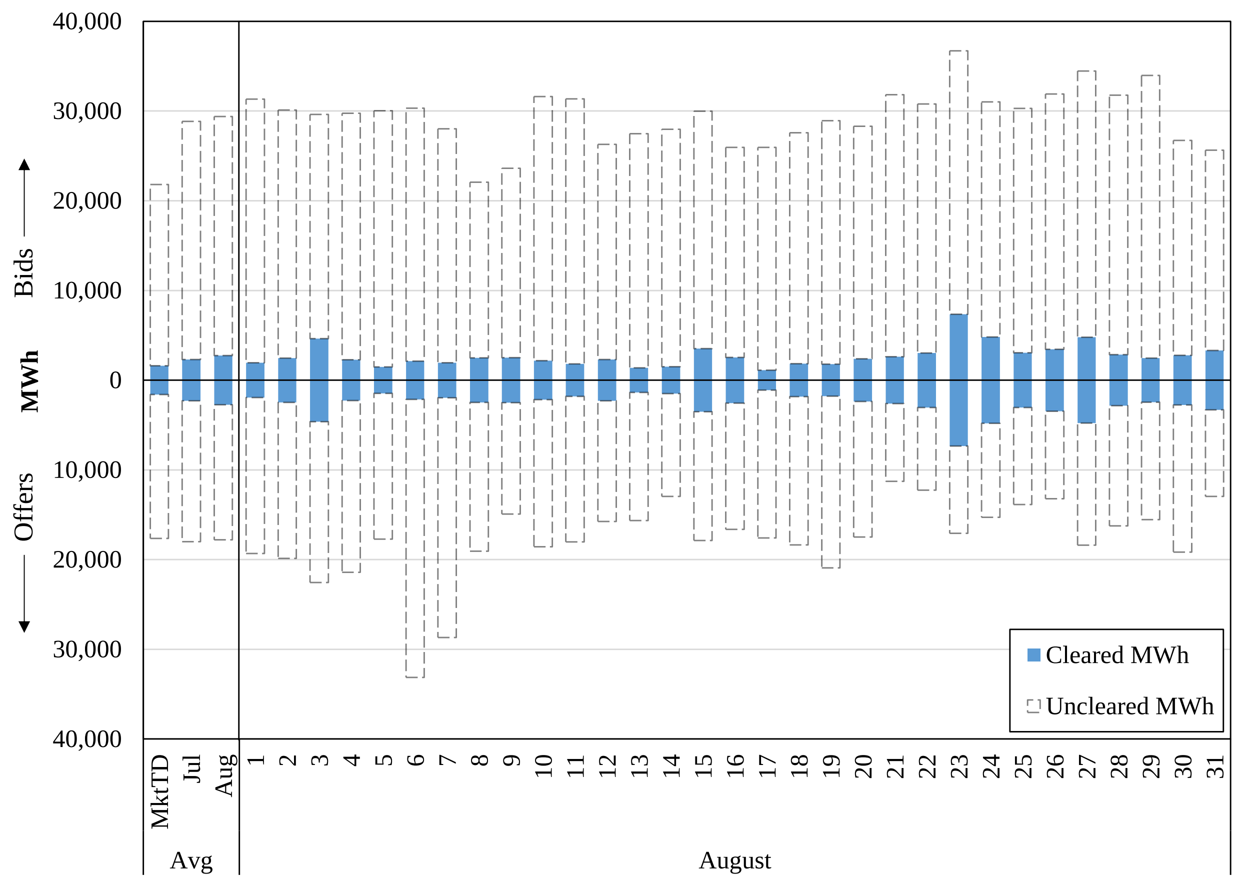
B. Market Activity

In this section, we summarize and discuss SEEM operations and outcomes to illuminate any potential operating or market issues. Our evaluation is in two main areas. First, is an overall review of the market trading, including volumes, prices, and characteristics of participation. Second is an evaluation of network usage, focusing on the key transmission paths and constraints.

1. Market Outcomes

SEEM cleared 84,000 MWh of energy in August, averaging approximately 2,700 MWh per day. Figure 1 illustrates daily SEEM bids and offers for August. Each bar represents the daily total MWh volume of SEEM activity. The bids and offers are divided between cleared bids to buy (blue bar above the x axis) and cleared offers to sell (blue bars below the x axis). The transparent bar stacked above the bids and below the offers are the uncleared bids and offers. The left side columns show activity relative to the previous month and relative to the market to date (MktTD). MktTD is the monthly average of all months since SEEM began in November 2022 (i.e., the November 2022 – August 2023 average).

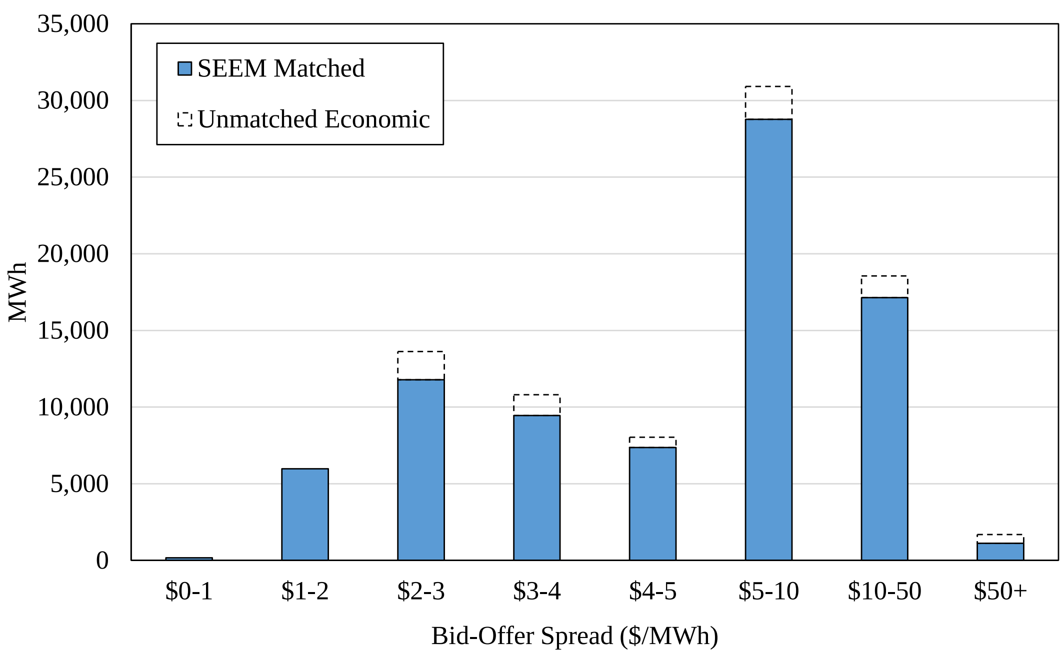
Figure 1: Daily Bids and Offers
August 2023



The average daily bid and offer quantities were higher in August than in July and higher than the MktTD average. The increase relative to MktTD is linked to the new participants that started trading at the end of June. The increase in August over July was about 15,000 MWh. This continues the overall trend of increased participation since the SEEM opening in November 2022. As the left-side monthly and MktTD bars show, total liquidity (cleared and uncleared bids and offers) remained relatively steady. Prior to the Florida expansion in June, the MktTD average was 48,000 MWh. The volumes since June have been 71,000 MWh and 86,000 MWh, clearly higher as a result of new members.

Like in previous months, we evaluated the uncleared bids and offers and found a notable volume of uncleared bids and offers with economic overlap in the sense that in an interval there are uncleared bids whose bid price is greater than some uncleared offer prices in the same interval. Of course, most economic uncleared matches have a small bid-offer spread, and likely are not matched due to transmission losses that render the trade uneconomic. However, there are some economic uncleared matches with substantial spreads. Figure 2 shows a summary of the cleared and uncleared matches. Each stacked bar shows the SEEM matches and the economic unmatched at the given bid-offer spread. For example, the first bar shows SEEM matches bids exceed offers by up to $1. The shadow boxes starting at the third bar show the uncleared economic bids and offers that did not clear even though the bid offer spread was greater than the average loss value of $2.

Figure 2: Cleared and Uncleared Economic Matches



About 8,000 MWh of bids/offers could settle at a price that could pay the average $2/MWh losses. In July, the amount was 18,000 MWh.[2] Without a complex simulation, there is not a straightforward way to determine why these bids and offers did not clear. Among the possibilities are transmission constraints and the need to use segments that had higher-than-average cost of losses. Counterparty constraints could also explain unmatched bids and offers.

There are also rare instances when transactions are matched but fail to clear the transmission scheduling process. These instances are attributable to occasional delays in approving transmission service requests (TSRs), so the tag is denied for being late. It may also result from insufficient ATC when the TSR is processed. SEEM downloads ATC values from OASIS twice an hour, so it is possible that real-time changes occur that result in insufficient ATC by the time the TSR is submitted. These failed transactions were less than 1/10 percent of the total bid/offered quantities.

Figure 3 shows more detail on the matched bids and offers by showing the matches by market participant. Like the prior figure, the bars above the x axis are cleared bids and the bars below are cleared offers. The bars in this figure are divided by participant, each color corresponds to a different participant (whether the participant is a buyer or seller). We do not reveal the identity of the participants in order to respect commercial sensitivity.

[2] We originally reported the July economic uncleared as 28,000 MWh. We have since revised our method to identify uncleared economic matches that results ed in lower volume.

Figure 3: Volumes of Matched Bids and Offers
August 2023

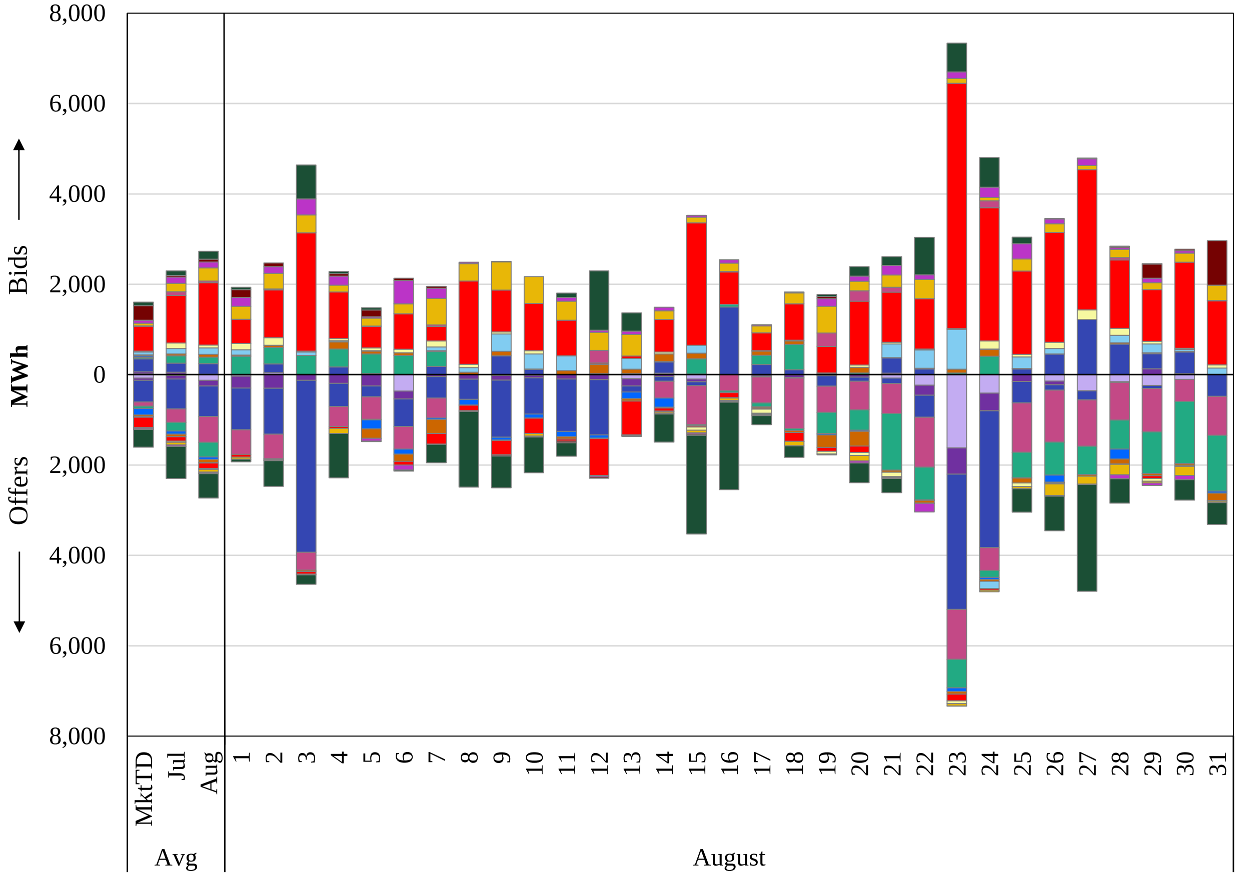
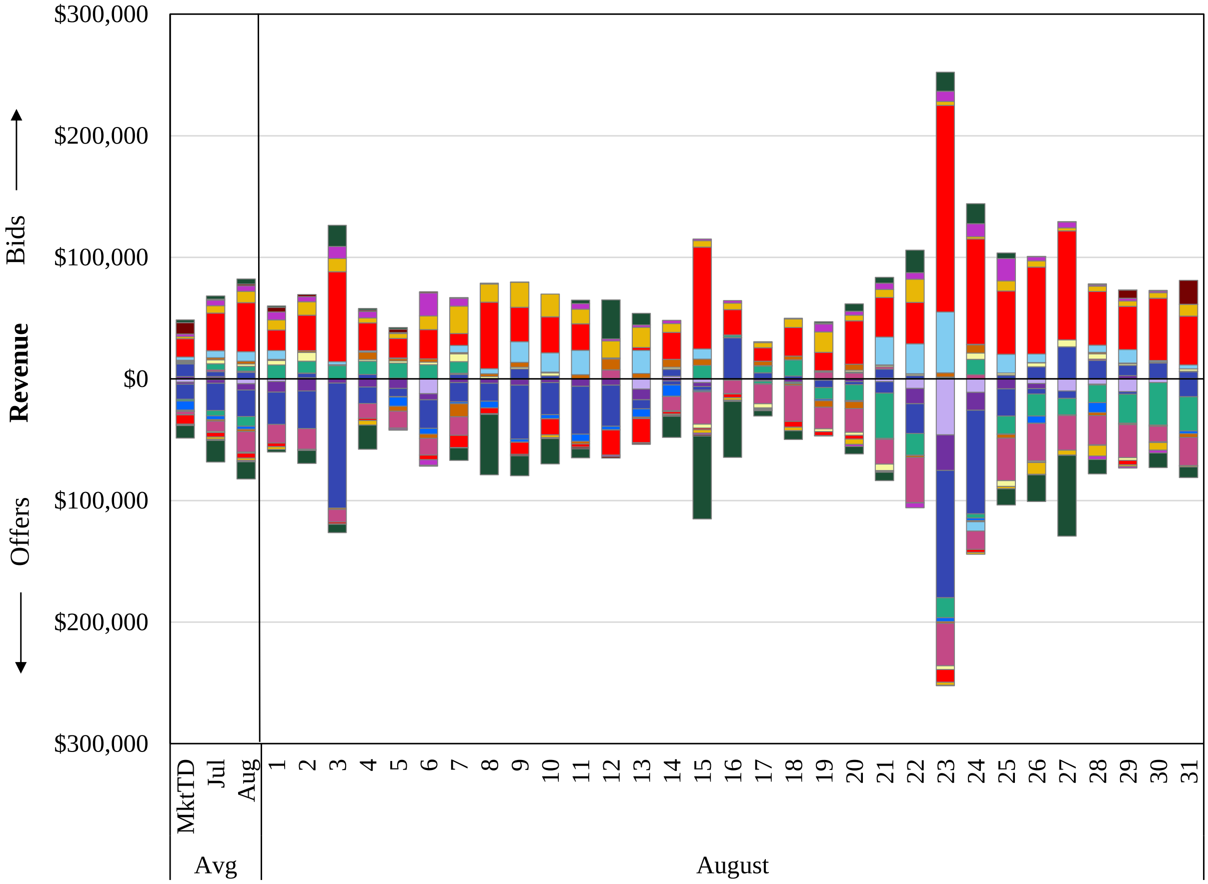


Figure 3 shows certain buyers and sellers comprise significant shares of the transaction activity. Twenty-five percent of the sales were made by a single participant and the two largest sellers accounted for 37 percent of the volume. On the buyer side, the largest buyer accounted for 51 percent of the cleared volume and the top two buyers accounted for 61 percent. Our findings in previous months indicate that the most active participants vary from month-to-month, both in identity and sales share, as can be observed by the left bar charts showing monthly and Market-to-Date (MktTD) averages. With the addition of new participants these concentration statistics have fallen since June.

Figure 4 is similar to Figure 3, but shows the revenues of matched transactions rather than the volumes. These are highly correlated with the transaction volumes shown in Figure 3.

Figure 4: Revenues of Matched Transactions
August 2023



2. Network Usage

In this subsection, we report on the usage of the SEEM network. Figure 4 shows the average daily peak-hour prices for August and the prices on the highest-priced and lowest-priced paths for each day. Figure 6 is the same figure but for off-peak hours.

The figures show in the left column the August prices compared to the previous period. It shows the average prices for are roughly equal to the prices in July but are lower than the average since market opening. This downward price trend is likely the result of sustained lower natural gas prices.

Figure 5: Average SEEM Clearing Prices: System-Wide and by Path
Peak Hours – August 2023

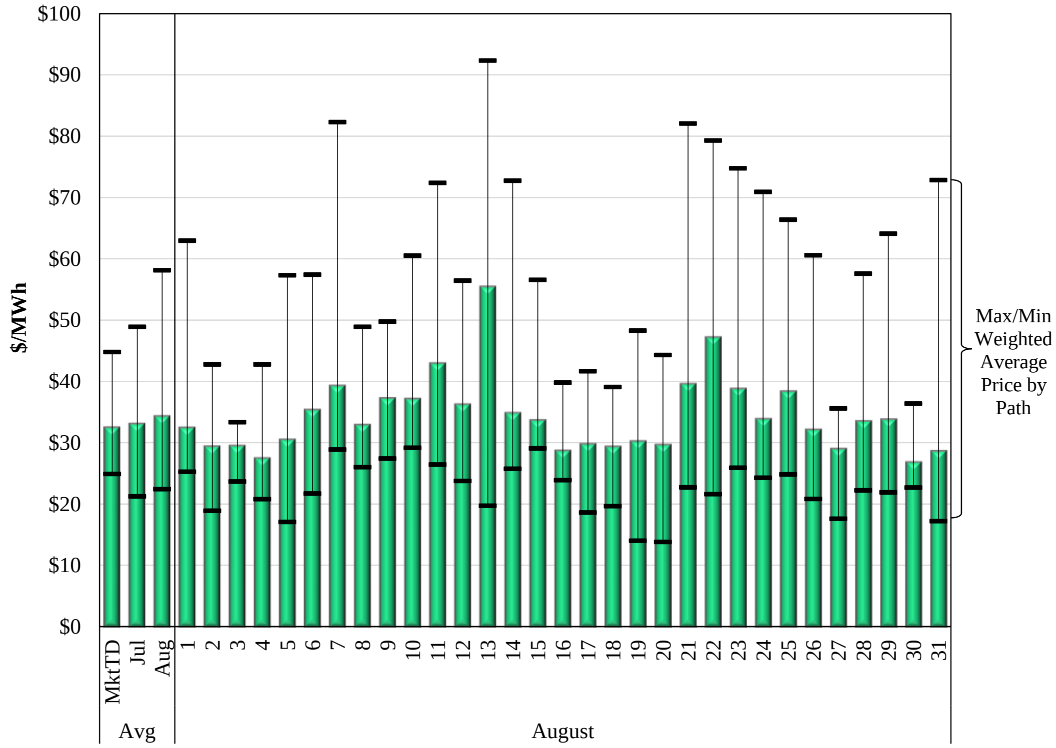
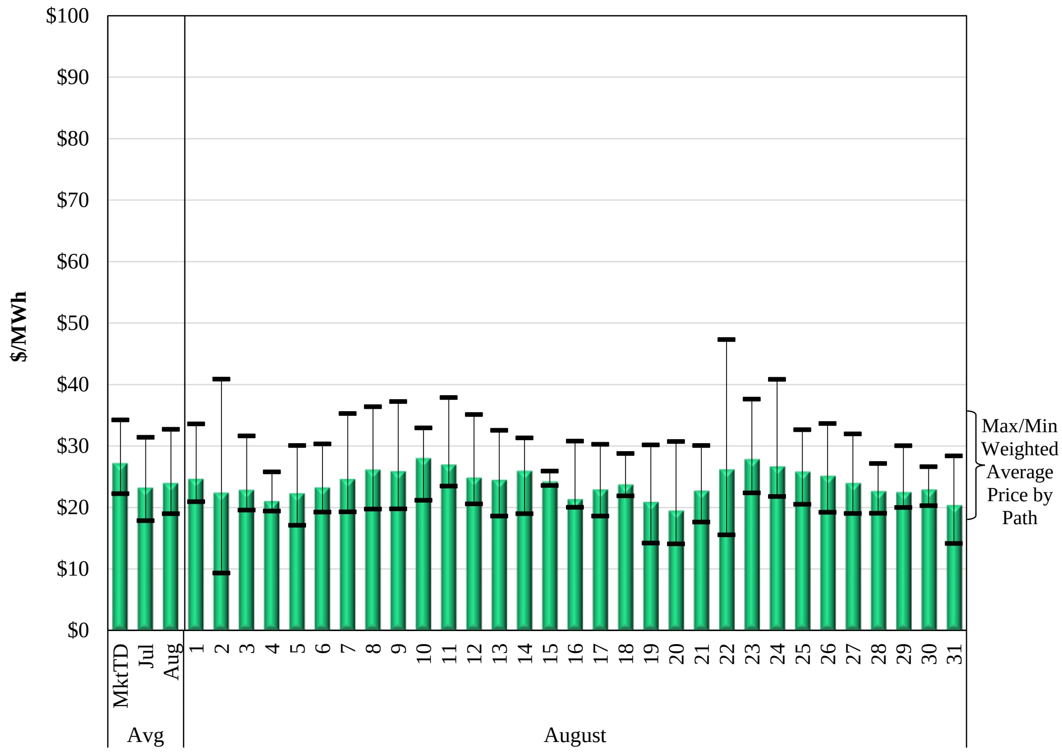


Figure 6: Average SEEM Clearing Prices: System-Wide and by Path
Off-Peak Hours – August 2023



The two figures show that the value of transactions can vary significantly by path, mainly because transmission constraints can contribute to higher prices between different locations. If a constraint prevents higher total flows between two (beneficial trading) areas, the average transaction price will be higher than if sufficient transmission capability was available to allow all beneficial trades to clear between the areas.

Accordingly, we evaluate SEEM transactions by path segments. SEEM trades among participants using ATC. We gathered ATC and trading statistics for all SEEM segments available to the model. With the addition of new members in June, SEEM uses 240 unique segments. We evaluated path data including the median, maximum, and minimum ATC values over all intervals for each segment, as well as the total MWh that cleared over each segment. We calculate a "loading factor" based on the scheduled transactions and ATC on the segment during each 15-minute interval. It is the portion of the path used in that interval relative to the maximum amount that could have been used based on the ATC.

Table 1 shows an excerpt of our statistics. The table displays the 36 segments that had more than 1,000 MWh of transactions scheduled during the month. The full data for all segments with at least 20 MWh scheduled during the month is provided in Appendix A. In addition to the ATC and schedule volumes, the Table also shows how each segment was utilized by interval during the month, *to wit*, the interval was either:

(1) Partially used (MWs cleared were less than ATC);

(2) Fully Used, ATC was used up for the interval;[3]

(3) Unavailable, no ATC;[4] and

(4) Uncleared (no schedules on the segment).

In reporting the usage of each segment, we refer to a "segment-intervals" which is an observation in a single interval on one segment. During the month, total segment intervals is the product of all 240 segments and the number of intervals during the month. In August, there were 714,240.[5] Of this total, the most common case in the data was case (4), where ATC was available, but the segment was not used because no beneficial transactions were cleared by the SEEM model over the intervals. These cases represent 642,858 segment intervals or 90 percent of all segment-intervals. The second most common case was case (3), where ATC was not sufficient to clear any SEEM transactions (56,389). The third most common case was case (1), intervals where the

[3] ATC less the MW schedule was less than 4 MW (i.e., no additional SEEM transaction could be cleared).

[4] ATC was less than 4 MW at the start of the interval.

[5] The maximum number of segment intervals in a month is (240 segments x 4 intervals x 24 hours x #days in the month). This is the maximum because occasionally the system requires shutting down for short periods to perform upgrades and other patches. In August, SEEM operated in all intervals.

segment was partially used (14,722). Finally, in a small number of intervals, case (2) prevailed where the segment was completely scheduled in the interval (271).

Table 1: Most Utilized SEEM Segment Statistics

Segment	ATC				Loading	Partially Used		Fully Used		Unavailable		Uncleared	
	Min	Median	Max	MWhs	Factor	Intervals	%	Intervals	%	Intervals	%	Intervals	%
S/CPL/CPLE-DUK//	836	3,911	6,877	17,945	0.006201	681	23%	0	0%	0	0%	2295	77%
F/TEC/TEC-FPC//	0	1,421	2,377	17,687	0.017351	1,581	53%	0	0%	4	0%	1391	47%
SS/SOCO/FL-SOCO//	252	488	734	16,893	0.047482	1,062	36%	0	0%	0	0%	1914	64%
S/DUK/CPLE-SOCO//	0	1,828	2,335	15,465	0.011626	649	22%	0	0%	1	0%	2326	78%
SS/SOCO/TVA-SOCO//	719	1,207	1,362	14,461	0.016324	413	14%	0	0%	0	0%	2563	86%
F/FPC/TEC-SOCO//	0	178	212	11,870	0.123171	1,073	36%	4	0%	828	28%	1071	36%
S/TVA/TVA-SOCO//	0	2,875	3,000	11,554	0.005690	313	11%	0	0%	8	0%	2655	89%
SS/SOCO/DUK-SOCO//	0	700	1,035	10,734	0.021944	346	12%	27	1%	13	0%	2590	87%
F/FPC/FPC-SOCO//	0	178	212	10,045	0.104399	567	19%	39	1%	828	28%	1542	52%
F/JEA/SOCO-JEA//	0	550	828	9,107	0.023087	1,114	37%	9	0%	92	3%	1761	59%
S/DUK/TVA-DUK//	0	692	692	5,950	0.012804	224	8%	7	0%	123	4%	2622	88%
F/FPC/TEC-FPC//	0	1,470	2,426	5,817	0.005503	707	24%	0	0%	4	0%	2265	76%
S/TVA/TVA-DUK//	0	333	333	5,323	0.023269	160	5%	0	0%	188	6%	2628	88%
S/AECI/AECI-TVA//	0	668	911	3,947	0.008553	141	5%	13	0%	104	3%	2718	91%
S/SCEG/SCEG-SOCO//	831	2,641	99,999	2,852	0.001380	308	10%	0	0%	0	0%	2668	90%
S/TVA/AECI-SOCO//	0	340	387	2,766	0.012483	111	4%	1	0%	216	7%	2648	89%
SS/SOCO/SOCO-FL//	1	1,033	1,500	2,475	0.003552	270	9%	4	0%	2	0%	2700	91%
S/TVA/DUK-TVA//	0	333	333	2,342	0.010764	99	3%	0	0%	64	2%	2813	95%
S/DUK/CPLE-TVA//	120	692	692	2,228	0.004598	75	3%	1	0%	0	0%	2900	97%
S/TVA/SOCO-TVA//	0	2,376	3,000	2,164	0.001442	73	2%	6	0%	308	10%	2589	87%
S/CPL/CPLE-SC//	0	1,972	4,319	2,107	0.001422	96	3%	0	0%	3	0%	2877	97%
S/DUK/DUK-SOCO//	0	1,776	2,335	1,959	0.001524	350	12%	0	0%	1	0%	2625	88%
P/LGEE/LGEE-TVA//	0	1,623	1,623	1,838	0.001649	177	6%	2	0%	146	5%	2651	89%
S/SC/CPLE-SOCO//	1,807	3,458	3,683	1,776	0.000710	68	2%	0	0%	0	0%	2908	98%
F/JEA/JEA-SOCO//	0	497	605	1,680	0.005228	305	10%	0	0%	40	1%	2631	88%
SS/SOCO/SOCO-SOCO//	39,640	43,556	43,556	1,523	0.000047	108	4%	0	0%	0	0%	2868	96%
S/MEAG/DUK-MEAG//	0	117	228	1,484	0.017648	108	4%	13	0%	24	1%	2831	95%
SS/SOCO/SCEG-SOCO//	0	167	197	1,481	0.012065	130	4%	10	0%	3	0%	2833	95%
SS/SOCO/DUK-FL/MULTIPATHALIAS/	0	622	1,035	1,456	0.003395	177	6%	7	0%	15	1%	2777	93%
S/DUK/SOCO-DUK//	0	1,993	2,264	1,362	0.001059	128	4%	0	0%	168	6%	2680	90%
S/TVA/LGEE-SOCO//	0	2,648	2,648	1,316	0.000687	96	3%	0	0%	4	0%	2876	97%
S/SC/SOCO-SC//	0	1,915	2,460	1,291	0.000942	87	3%	0	0%	4	0%	2885	97%
F/TEC/FPC-TEC//	0	2,226	3,129	1,214	0.000798	120	4%	0	0%	36	1%	2820	95%
SS/SOCO/SC-SOCO//	257	449	571	1,153	0.003423	72	2%	0	0%	0	0%	2904	98%
S/MEAG/FPC-MEAG//	0	67	267	1,072	0.016933	96	3%	11	0%	34	1%	2835	95%
SS/GTC/SCEG-GTC//	0	91	107	1,006	0.015248	85	3%	1	0%	92	3%	2798	94%

These statistics indicate that among these most utilize segments, ATC remains available for SEEM trades. For example, many of the top paths have over 90 percent of their intervals uncleared. There are, however, numerous instances when segments are constrained. A constrained segment is one where either ATC is insufficient (less than 4 MW) prior to SEEM matching, or the segment is completely used by SEEM in at least one interval during the hour. These two circumstances (Cases (2) and (3)) occur in over 56,000 segment-intervals and almost always because the ATC is insufficient to schedule (i.e., ATC < 4 MW) rather than because it is filled by a SEEM match.

Further insight on constrained segments can be gained from Table 2. It shows the segments most often unavailable to SEEM (i.e., unavailable at least 20 percent of the intervals). Like in previous months, paths that are unavailable due to no ATC, are generally unused when they are available.

The incidence of transmission capacity constraints decreased between July and August, as measured by the percentage of constrained segment intervals (11 percent in July and 8 percent in August).

Table 2: Most Constrained SEEM Segments

Segment	ATC				Loading	Partially Used		Fully Used		Unavailable		Uncleared	
	Min	Median	Max	MWhs	Factor	Intervals	%	Intervals	%	Intervals	%	Intervals	%
F/JEA/SEC-JEA/SSN-JEA/	0	0	0	0	N/A	0	*0%*	0	*0%*	2,976	*100%*	0	*0%*
S/TVA/CPLW-AECI//	0	0	276	16	0.000571	2	*0%*	0	*0%*	2,493	*84%*	481	*16%*
S/TVA/SOCO-CPLW//	0	0	276	0	0.000000	0	*0%*	0	*0%*	2,272	*76%*	704	*24%*
S/TVA/AECI-CPLW//	0	0	276	5	0.000088	1	*0%*	0	*0%*	2,120	*71%*	855	*29%*
S/TVA/CPLW-DUK//	0	0	276	0	0.000000	0	*0%*	0	*0%*	2,108	*71%*	868	*29%*
S/TVA/DUK-CPLW//	0	0	276	0	0.000000	0	*0%*	0	*0%*	2,092	*70%*	884	*30%*
S/TVA/CPLW-LGEE//	0	0	276	0	0.000000	0	*0%*	0	*0%*	2,080	*70%*	896	*30%*
S/TVA/TVA-CPLW//	0	0	276	85	0.001385	4	*0%*	0	*0%*	2,080	*70%*	892	*30%*
S/TVA/LGEE-CPLW//	0	0	276	41	0.000665	4	*0%*	0	*0%*	2,076	*70%*	896	*30%*
S/TVA/CPLW-SOCO//	0	0	276	67	0.001079	3	*0%*	0	*0%*	2,076	*70%*	897	*30%*
S/TVA/CPLW-TVA//	0	0	276	169	0.002723	7	*0%*	0	*0%*	2,076	*70%*	893	*30%*
S/CPL/TVA-CPLW//	0	0	276	0	0.000000	0	*0%*	0	*0%*	1,903	*64%*	1073	*36%*
S/CPL/CPLW-TVA//	0	0	276	0	0.000000	0	*0%*	0	*0%*	1,894	*64%*	1082	*36%*
S/CPL/TVA-DUK//	0	0	276	131	0.001760	8	*0%*	1	*0%*	1,889	*63%*	1078	*36%*
S/CPL/DUK-TVA//	0	0	276	252	0.003379	12	*0%*	0	*0%*	1,887	*63%*	1077	*36%*
S/AECI/TVA-AECI//	0	0	911	103	0.000940	9	*0%*	0	*0%*	1,628	*55%*	1339	*45%*
S/MEAG/MEAG-SC//	0	32	71	46	0.002041	4	*0%*	1	*0%*	1,092	*37%*	1879	*63%*
F/FPC/SOCO-FPC/SOCO-FPCS/	0	100	480	0	0.000000	0	*0%*	0	*0%*	928	*31%*	2048	*69%*
F/FPC/SOCO-TEC//	0	100	480	561	0.005040	50	*2%*	4	*0%*	928	*31%*	1994	*67%*
F/FPC/SOCO-FPC//	0	100	480	616	0.005511	114	*4%*	36	*1%*	920	*31%*	1906	*64%*
F/FPC/SOCO-SEC/SOCO-SSN/	0	100	480	0	0.000000	0	*0%*	0	*0%*	920	*31%*	2056	*69%*
F/FPC/SOCO-GVL//	0	100	292	0	0.000000	0	*0%*	0	*0%*	920	*31%*	2056	*69%*
F/FPC/SEC-SOCO/SSN-SOCO/	0	178	212	0	0.000000	0	*0%*	0	*0%*	840	*28%*	2136	*72%*
F/FPC/SEC-SOCO/SSO-SOCO/	0	176	212	0	0.000000	0	*0%*	0	*0%*	832	*28%*	2144	*72%*
F/FPC/FPC-SOCO//	0	178	212	10,045	0.104399	567	*19%*	39	*1%*	828	*28%*	1542	*52%*
F/FPC/GVL-SOCO//	0	178	212	0	0.000000	0	*0%*	0	*0%*	828	*28%*	2148	*72%*
F/FPC/TEC-SOCO//	0	178	212	11,870	0.123171	1,073	*36%*	4	*0%*	828	*28%*	1071	*36%*
S/TVA/SOCO-AECI//	0	287	600	15	0.000072	1	*0%*	0	*0%*	784	*26%*	2191	*74%*
S/TVA/DUK-AECI//	0	286	333	48	0.000314	6	*0%*	0	*0%*	776	*26%*	2194	*74%*
S/TVA/TVA-AECI//	0	287	600	0	0.000000	0	*0%*	0	*0%*	776	*26%*	2200	*74%*
S/TVA/LGEE-AECI//	0	288	600	24	0.000111	2	*0%*	0	*0%*	732	*25%*	2242	*75%*

III. Conclusion

We reviewed the operation of SEEM for August 2023. We have developed operational procedures to validate the market rules and constraints of SEEM. All of our screens have been validated and we conclude the SEEM operated within the rules and constraints. We also have evaluated the SEEM outcomes and have not identified significant operating issues.

Appendix A

SEEM Path Usage

Segment	ATC				Loading	Partially Used		Fully Used		Unavailable		Uncleared	
	Min	Median	Max	MWhs	Factor	Intervals	%	Intervals	%	Intervals	%	Intervals	%
S/CPL/CPLE-DUK//	836	3,911	6,877	17,945	0.006201	681	23%	0	0%	0	0%	2295	77%
F/TEC/TEC-FPC//	0	1,421	2,377	17,687	0.017351	1,581	53%	0	0%	4	0%	1391	47%
SS/SOCO/FL-SOCO//	252	488	734	16,893	0.047482	1,062	36%	0	0%	0	0%	1914	64%
S/DUK/CPLE-SOCO//	0	1,828	2,335	15,465	0.011626	649	22%	0	0%	1	0%	2326	78%
SS/SOCO/TVA-SOCO//	719	1,207	1,362	14,461	0.016324	413	14%	0	0%	0	0%	2563	86%
F/FPC/TEC-SOCO//	0	178	212	11,870	0.123171	1,073	36%	4	0%	828	28%	1071	36%
S/TVA/TVA-SOCO//	0	2,875	3,000	11,554	0.005690	313	11%	0	0%	8	0%	2655	89%
SS/SOCO/DUK-SOCO//	0	700	1,035	10,734	0.021944	346	12%	27	1%	13	0%	2590	87%
F/FPC/FPC-SOCO//	0	178	212	10,045	0.104399	567	19%	39	1%	828	28%	1542	52%
F/JEA/SOCO-JEA//	0	550	828	9,107	0.023087	1,114	37%	9	0%	92	3%	1761	59%
S/DUK/TVA-DUK//	0	692	692	5,950	0.012804	224	8%	7	0%	123	4%	2622	88%
F/FPC/TEC-FPC//	0	1,470	2,426	5,817	0.005503	707	24%	0	0%	4	0%	2265	76%
S/TVA/TVA-DUK//	0	333	333	5,323	0.023269	160	5%	0	0%	188	6%	2628	88%
S/AECI/AECI-TVA//	0	668	911	3,947	0.008553	141	5%	13	0%	104	3%	2718	91%
S/SCEG/SCEG-SOCO//	831	2,641	99,999	2,852	0.001380	308	10%	0	0%	0	0%	2668	90%
S/TVA/AECI-SOCO//	0	340	387	2,766	0.012483	111	4%	1	0%	216	7%	2648	89%
SS/SOCO/SOCO-FL//	1	1,033	1,500	2,475	0.003552	270	9%	4	0%	2	0%	2700	91%
S/TVA/DUK-TVA//	0	333	333	2,342	0.010764	99	3%	0	0%	64	2%	2813	95%
S/DUK/CPLE-TVA//	120	692	692	2,228	0.004598	75	3%	1	0%	0	0%	2900	97%
S/TVA/SOCO-TVA//	0	2,376	3,000	2,164	0.001442	73	2%	6	0%	308	10%	2589	87%
S/CPL/CPLE-SC//	0	1,972	4,319	2,107	0.001422	96	3%	0	0%	3	0%	2877	97%
S/DUK/DUK-SOCO//	0	1,776	2,335	1,959	0.001524	350	12%	0	0%	1	0%	2625	88%
P/LGEE/LGEE-TVA//	0	1,623	1,623	1,838	0.001649	177	6%	2	0%	146	5%	2651	89%
S/SC/CPLE-SOCO//	1,807	3,458	3,683	1,776	0.000710	68	2%	0	0%	0	0%	2908	98%
F/JEA/JEA-SOCO//	0	497	605	1,680	0.005228	305	10%	0	0%	40	1%	2631	88%
SS/SOCO/SOCO-SOCO//	39,640	43,556	43,556	1,523	0.000047	108	4%	0	0%	0	0%	2868	96%
S/MEAG/DUK-MEAG//	0	117	228	1,484	0.017648	108	4%	13	0%	24	1%	2831	95%
SS/SOCO/SCEG-SOCO//	0	167	197	1,481	0.012065	130	4%	10	0%	3	0%	2833	95%
SS/SOCO/DUK-FL/MULTIPATHALIAS/	0	622	1,035	1,456	0.003395	177	6%	7	0%	15	1%	2777	93%
S/DUK/SOCO-DUK//	0	1,993	2,264	1,362	0.001059	128	4%	0	0%	168	6%	2680	90%
S/TVA/LGEE-SOCO//	0	2,648	2,648	1,316	0.000687	96	3%	0	0%	4	0%	2876	97%
S/SC/SOCO-SC//	0	1,915	2,460	1,291	0.000942	87	3%	0	0%	4	0%	2885	97%
F/TEC/FPC-TEC//	0	2,226	3,129	1,214	0.000798	120	4%	0	0%	36	1%	2820	95%
SS/SOCO/SC-SOCO//	257	449	571	1,153	0.003423	72	2%	0	0%	0	0%	2904	98%
S/MEAG/FPC-MEAG//	0	67	267	1,072	0.016933	96	3%	11	0%	34	1%	2835	95%
SS/GTC/SCEG-GTC//	0	91	107	1,006	0.015248	85	3%	1	0%	92	3%	2798	94%
SS/GTC/DUK-GTC//	0	372	650	981	0.003743	42	1%	10	0%	202	7%	2722	91%
SS/SOCO/SOCO-TVA//	639	2,843	3,949	796	0.000402	23	1%	0	0%	0	0%	2953	99%
S/TVA/AECI-TVA//	0	339	387	795	0.003596	28	1%	0	0%	216	7%	2732	92%
SS/SOCO/FL-TVA/MULTIPATHALIAS/	252	488	734	749	0.002105	47	2%	0	0%	0	0%	2929	98%
S/MEAG/SOCO-MEAG//	2,671	2,941	3,195	715	0.000327	43	1%	0	0%	0	0%	2933	99%
S/CPL/SCEG-CPLE//	0	632	632	672	0.001641	113	4%	1	0%	50	2%	2812	94%
S/CPL/CPLE-SCEG//	0	412	412	657	0.002541	46	2%	0	0%	292	10%	2638	89%
F/FPC/FPC-TEC//	0	2,266	3,169	653	0.000420	66	2%	0	0%	24	1%	2886	97%
SS/GTC/SOCO-GTC//	12,786	13,226	14,660	649	0.000066	58	2%	0	0%	0	0%	2918	98%
SS/GTC/FPC-GTC//	0	303	462	624	0.002997	58	2%	6	0%	20	1%	2892	97%
S/SCEG/CPLE-SOCO//	140	475	99,999	620	0.001538	43	1%	0	0%	0	0%	2933	99%
F/FPC/SOCO-FPC//	0	100	480	616	0.005511	114	4%	36	1%	920	31%	1906	64%
F/FPC/SOCO-TEC//	0	100	480	561	0.005040	50	2%	4	0%	928	31%	1994	67%
SS/SOCO/FL-SC/MULTIPATHALIAS/	25	159	476	536	0.004900	67	2%	2	0%	0	0%	2907	98%
S/SCEG/SCEG-CPLE//	500	672	99,999	463	0.000842	83	3%	0	0%	0	0%	2893	97%
S/TVA/LGEE-DUK//	0	333	333	457	0.001888	97	3%	0	0%	36	1%	2843	96%
SS/GTC/TVA-GTC//	0	287	321	444	0.002151	27	1%	3	0%	8	0%	2938	99%
S/CPL/DUK-CPLE//	479	3,346	6,575	440	0.000175	94	3%	0	0%	0	0%	2882	97%
SS/GTC/SC-GTC//	136	170	216	426	0.003326	35	1%	2	0%	0	0%	2939	99%

Appendix A (continued)

Segment	ATC			MWhs	Loading Factor	Partially Used		Fully Used		Unavailable		Uncleared	
	Min	Median	Max			Intervals	%	Intervals	%	Intervals	%	Intervals	%
SS/SOCO/SCEG-FL/MULTIPATHALIAS/	0	167	197	417	0.003496	82	3%	0	0%	5	0%	2889	97%
S/SCEG/SCEG-DUK//	535	684	99,999	386	0.000687	65	2%	0	0%	0	0%	2911	98%
S/TVA/AECI-DUK//	0	326	333	381	0.001888	24	1%	5	0%	260	9%	2687	90%
S/MEAG/MEAG-SOCO//	2,498	2,660	2,930	363	0.000182	24	1%	0	0%	0	0%	2952	99%
S/SC/DUK-SC//	1,081	2,365	2,861	350	0.000199	68	2%	0	0%	0	0%	2908	98%
S/SC/CPLE-SC//	554	2,106	3,343	331	0.000213	28	1%	0	0%	0	0%	2948	99%
S/DUK/DUK-SC//	0	1,579	2,788	331	0.000279	67	2%	0	0%	3	0%	2906	98%
S/DUK/SCEG-DUK//	0	663	664	265	0.000574	44	1%	0	0%	122	4%	2810	94%
SS/SOCO/FL-DUK/MULTIPATHALIAS/	89	476	712	263	0.000794	47	2%	0	0%	0	0%	2929	98%
S/MEAG/TVA-MEAG//	45	86	217	255	0.003300	18	1%	5	0%	0	0%	2953	99%
S/CPL/DUK-TVA//	0	0	276	252	0.003379	12	0%	0	0%	1,887	63%	1077	36%
S/DUK/CPLE-CPLW//	0	466	554	252	0.000866	12	0%	0	0%	171	6%	2793	94%
SS/SOCO/FL-SCEG/MULTIPATHALIAS/	33	107	160	244	0.003238	42	1%	0	0%	0	0%	2934	99%
SS/GTC/JEA-GTC//	0	303	462	234	0.001124	46	2%	0	0%	20	1%	2910	98%
S/DUK/DUK-TVA//	0	692	692	219	0.000453	37	1%	0	0%	1	0%	2938	99%
S/SCEG/SOCO-CPLE//	500	672	99,999	197	0.000358	30	1%	0	0%	0	0%	2946	99%
S/DUK/TVA-CPLE//	0	692	692	191	0.000411	45	2%	0	0%	155	5%	2776	93%
S/DUK/SOCO-CPLE//	0	2,062	2,264	191	0.000141	47	2%	0	0%	200	7%	2729	92%
S/MEAG/MEAG-JEA//	0	192	266	189	0.001616	29	1%	0	0%	223	7%	2724	92%
S/SCEG/SOCO-SCEG//	0	990	99,999	186	0.000246	19	1%	0	0%	351	12%	2606	88%
S/TVA/CPLW-TVA//	0	0	276	169	0.002723	7	0%	0	0%	2,076	70%	893	30%
SS/SOCO/TVA-FL/MULTIPATHALIAS/	1	972	1,362	167	0.000257	28	1%	2	0%	2	0%	2944	99%
S/MEAG/SCEG-MEAG//	11	19	23	157	0.010742	8	0%	30	1%	0	0%	2938	99%
SS/SOCO/TVA-DUK/MULTIPATHALIAS	89	573	957	151	0.000358	8	0%	0	0%	0	0%	2968	100%
S/CPL/TVA-DUK//	0	0	276	131	0.001760	8	0%	1	0%	1,889	63%	1078	36%
S/SC/SC-SOCO//	452	2,762	3,547	119	0.000058	119	4%	0	0%	0	0%	2857	96%
S/MEAG/SC-MEAG//	0	43	100	111	0.002666	11	0%	6	0%	16	1%	2943	99%
S/DUK/SCEG-SOCO//	479	663	664	109	0.000223	18	1%	0	0%	0	0%	2958	99%
S/MEAG/MEAG-TVA//	0	139	198	108	0.001222	9	0%	0	0%	192	6%	2775	93%
S/CPL/SC-CPLE//	0	1,743	2,880	104	0.000084	56	2%	0	0%	46	2%	2874	97%
S/AECI/TVA-AECI//	0	0	911	103	0.000940	9	0%	0	0%	1,628	55%	1339	45%
SS/SOCO/SC-FL/MULTIPATHALIAS/	1	435	571	95	0.000307	27	1%	0	0%	2	0%	2947	99%
S/MEAG/MEAG-DUK//	0	81	159	94	0.001533	12	0%	1	0%	72	2%	2891	97%
S/TVA/DUK-SOCO//	0	333	333	92	0.000414	7	0%	0	0%	20	1%	2949	99%
SS/SOCO/SOCO-DUK//	89	573	957	89	0.000211	21	1%	0	0%	0	0%	2955	99%
S/DUK/CPLW-DUK//	0	248	862	85	0.000462	4	0%	0	0%	121	4%	2851	96%
S/TVA/TVA-CPLW//	0	0	276	85	0.001385	4	0%	0	0%	2,080	70%	892	30%
SS/GTC/GTC-SOCO//	20,000	20,000	20,000	75	0.000005	4	0%	0	0%	0	0%	2972	100%
S/TVA/CPLW-SOCO//	0	0	276	67	0.001079	3	0%	0	0%	2,076	70%	897	30%
S/MEAG/JEA-MEAG//	0	67	267	60	0.000948	18	1%	0	0%	34	1%	2924	98%
S/SC/SOCO-CPLE//	0	2,269	3,149	57	0.000034	17	1%	0	0%	4	0%	2955	99%
S/SC/SC-DUK//	1,323	2,397	3,616	50	0.000028	50	2%	0	0%	0	0%	2926	98%
S/TVA/DUK-AECI//	0	286	333	48	0.000314	6	0%	0	0%	776	26%	2194	74%
S/DUK/SC-DUK//	0	1,819	2,920	47	0.000036	47	2%	0	0%	119	4%	2810	94%
S/SC/SC-CPLE//	287	2,550	3,722	47	0.000025	47	2%	0	0%	0	0%	2929	98%
S/MEAG/MEAG-SC//	0	32	71	46	0.002041	4	0%	1	0%	1,092	37%	1879	63%
S/DUK/CPLW-CPLE//	0	255	962	46	0.000230	5	0%	0	0%	37	1%	2934	99%
S/MEAG/GTC-MEAG//	1,613	1,985	2,183	45	0.000031	5	0%	0	0%	0	0%	2971	100%
SS/GTC/GTC-MEAG//	9,546	9,914	9,999	45	0.000006	5	0%	0	0%	0	0%	2971	100%
S/TVA/LGEE-CPLW//	0	0	276	41	0.000665	4	0%	0	0%	2,076	70%	896	30%
SS/GTC/GTC-DUK//	0	371	601	40	0.000147	4	0%	0	0%	4	0%	2968	100%
S/SCEG/CPLE-SCEG//	122	475	99,999	37	0.000093	3	0%	0	0%	0	0%	2973	100%
SS/SOCO/SOCO-SCEG//	33	107	160	36	0.000478	2	0%	1	0%	0	0%	2973	100%
S/MEAG/MEAG-GTC//	2,488	2,686	3,058	30	0.000015	2	0%	0	0%	0	0%	2974	100%
SS/GTC/MEAG-GTC//	8,657	8,787	9,152	30	0.000005	2	0%	0	0%	0	0%	2974	100%
S/TVA/LGEE-AECI//	0	288	600	24	0.000111	2	0%	0	0%	732	25%	2242	75%
S/MEAG/MEAG-FPC//	0	192	266	22	0.000188	4	0%	0	0%	223	7%	2749	92%
S/DUK/SOCO-TVA//	120	692	692	20	0.000041	5	0%	0	0%	0	0%	2971	100%

Appendix 8

Power Supply SEEM Trading Guidance

Background / Market Structure

The Southeast Energy Exchange Market (SEEM) is an automated, intra-hour system to match buyers and sellers with the goal of adding an efficient bilateral market when unused transmission capacity is available. Power transactions are voluntary and non-firm. SEEM participation for LG&E/KU will be in addition to current participation in existing bilateral and RTO markets.

A new transmission product, NFEETS, has been created for this market. NFEETS is the unutilized transmission that is available after the traditional reservation window has closed. The cost for this transmission is $0/MWh and it will have the lowest NERC priority. The only transmission costs associated with the SEEM platform will be financial losses paid to the Transmission Service Providers.

The matching process will occur every 15 minutes, with bids and offers submitted no later than 15 minutes prior to scheduled flow. The automated market matching, transmission requests, and tag creation/approval must happen prior to the standard start of the ramping window, five minutes prior to flow.

The matching algorithm seeks to maximize the benefit to participants when pairing bids and offers. The clearing price is a midpoint of the matched bids/offers with an adjustment for financial losses incurred.

Reliability, load conditions, and system conditions determine the real-time level of trading activity.

Power Supply will seek to maximize SEEM benefits to customers by including SEEM considerations into ongoing bilateral/RTO trading decisions. SEEM does not have the after-the-fact price risk of RTO transactions. Power Supply anticipates entering bids and offers into most SEEM trading intervals when system conditions permit.

Volume Limitations for SEEM

The structure of SEEM allows for tag approval up to the start of ramping. The tighter tagging window and the intra-hour variability will be the primary driver of bid/offer volumes provided by Dispatch to Trading for potential SEEM transactions.

Dispatch will provide the Power Trader with a total hourly volume available for purchases and sales in the upcoming trading hour and each SEEM interval (based on load, generation conditions, and ramping capability). Constraints may include unit limitations, weather conditions, and potential variability of large customer demand. Volumes bid or offered into SEEM will not exceed the ramping capabilities of online generation.

SEEM Purchasing

Traders will submit bids for power based on purchasing guidance provided by Dispatch and management. Dispatch will provide a volume for economic purchases for the hour, or 15-minute interval if load or generation conditions change. The trader will utilize the Generation Cost Calculator (GCC) to provide an estimate of the generation costs a purchase would offset. The GCC utilizes forecasted load, real-time generation parameters, and incremental heat rate curves to estimate which units would be lowered by the Energy Management System (EMS) to accommodate a purchase. This offset generation is then priced by the GCC using FIFO methodology for fuel, thereby simulating the company's After the Fact Billing (AFB) process.

Traders will evaluate RTO markets, third party offers, and SEEM orders and execution trends to determine if power can likely be purchased below generation cost through any of these markets. For SEEM, bids will initially be targeted to be a minimum of 10% below the average cost of the offset generation. This target margin will be adjusted to meet native load requirements and in response to real time market conditions.

Factors, such as fuel supply limitations, may warrant purchasing at a price above the current economic pricing determined by the GCC. Management will provide that guidance to traders. In this situation, when a purchase price is above the economic pricing determined by the GCC and purchase bids are submitted to SEEM, power sales will be prohibited to ensure compliance with the TVA ACT.

Purchasing Process

1) Dispatch provides Trading with an hourly volume (MW) and a volume for each 15-minute SEEM interval that could be imported to serve load based on real time system conditions.
2) Trader utilizes the GCC to determine the generation costs a purchase would offset.
3) Trader canvases available markets and offers and determines if SEEM bids are warranted and enters bids into SEEM accordingly.

SEEM Sales

Traders will be given a total hourly volume and a SEEM volume for each 15-minute interval available for sales by Dispatch. Traders will utilize the GCC to determine the highest cost generation required to meet the sales volume.

Traders will evaluate existing RTO markets, third party bids, and SEEM orders and execution trends to forecast if power can likely be sold above generation cost in hourly markets and/or if offers into SEEM are warranted. For SEEM, margin requirements will be based on the most current Off-System Sales guidance provided by management but will be initially targeted at no less than 15%. This guidance may be impacted by factors including fuel supply limitations, weather conditions, or unit constraints.

SEEM offer volumes provided by Dispatch may be lower than total sales volumes. Traders may offer the maximum volume into SEEM and also participate in RTO or fixed price sales to other counterparties. If traditional bilateral or RTO sales offer a premium margin, a trader may forgo participation in SEEM. Traders will evaluate the potential opportunities associated with each market; RTO pricing is after-the-fact and can be volatile, while a SEEM offer might not be matched. Participating in one market in some cases may result in an opportunity cost of participating in another market.

Sales Process

1) Dispatch provides Trading with an hourly volume (MW) and a volume for each 15-minute SEEM interval based on real time system conditions.
2) Trader utilizes the GCC to the highest cost generation to meet the total sales volume.

3) Trader canvases available markets and bids and determines if SEEM offers are warranted and enters offers into SEEM accordingly.

Trading Evaluation and offer evolution

The SEEM platform provides no pricing data for other participants. Price discovery is limited to orders entered into the system by Power Supply and execution trends. The dynamic order and execution data from the 15-minute SEEM market will be used in conjunction with ongoing evaluations of RTO and third-party markets to inform the next hours' trading decision. All purchase and sales transactions are reviewed dynamically, and adjustments are made real-time by traders.

Daily reports review and confirm margins, assuring pricing tools are accurate. Trading will produce a Quarterly analysis of the trading performance and the benefit to customers derived from each market.