UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER22-2984-000**

PROTEST
OF THE PJM POWER PROVIDERS GROUP

On September 30, 2022, PJM Interconnection, L.L.C. ("PJM") submitted revisions[1] to the PJM Open Access Transmission Tariff ("Tariff") to revise certain elements of the Reliability Pricing Model ("RPM") auction parameters that PJM is required by tariff to review every four years through an analysis and stakeholder process ("PJM Filing").

On September 30, 2022, the Federal Energy Regulatory Commission (the "Commission") issued a Combined Notice of Filings #2 setting October 21, 2022, as the deadline for filing an intervention or protest regarding the PJM Filing. On October 5, 2022, The PJM Power Providers ("P3")[2] filed a doc-less Motion to Intervene. Pursuant

[1] *PJM Interconnection, L.L.C.,* Docket No. ER22-2984-000 (filed September 30, 2022) ("PJM filing").

[2] P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM Interconnection, L.L.C. ("PJM") region. Combined, P3 members own over 67,000 MWs of generation assets and produce enough power to supply over 50 million homes in the PJM region covering 13 states and the District of Columbia.

to Rule 211 of the Rules of Practice and Procedure of the Commission, 18 C.F.R. §§ 385.211 (2022), P3 hereby provides this protest,[3] in the above-captioned proceeding.

I. BACKGROUND

The PJM Tariff requires that for the 2018-2019 Delivery Year and for every fourth Delivery Year thereafter PJM perform a review of the shape of the Variable Resource Requirement ("VRR") curve used to clear the RPM auctions and key inputs to that curve.[4] In pursuit of that mandate, PJM retained The Brattle Group ("Brattle") as an independent consultant to assist with the quadrennial review. PJM also retained the consulting firm Sargent & Lundy ("S&L") regarding generation plant cost estimates. Brattle conducted one study: The Fifth Review of PJM's Variable Resource Requirement Curve ("2022 VRR Curve Study")[5] and Brattle and S&L conducted a second study titled PJM CONE 2026/2027 Report ("2022 CONE Report").[6] Based on the two reports PJM is proposing changes to the VRR curve shape, the Reference Resource, the gross CONE values, and the net energy and ancillary service ("EAS") revenue offset methodology for implementation beginning with the November 2023 base residual auction ("BRA") associated with the 2026/2027 Delivery Year.[7] PJM proposed its recommendations to the

[3]The comments contained herein represent the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue. For more information on P3, visit www.p3powergroup.com

[4] Tariff, Attachment DD, section 5.10(a)(iii).

[5] PJM Filing Attachment C, Affidavit of Kathleen Spees and Samuel A. Newell ("VRR Curve Aff.") (the 2022 VRR Curve Study is Exhibit 2, to Attachment C).

[6] PJM Filing Attachment D, Affidavit of Samuel A. Newell, John H. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, LLC "(Brattle/S&L CONE Affidavit") (the 2022 CONE Report is Exhibit No. 2 to Attachment D).

[7] PJM Filing at p 3.

PJM stakeholders at the May 11, 2022 Market Implementation Committee ("MIC") and a stakeholder vote was taken at both the Markets and Reliability Committee and Members Committee on August 24, 2022. There were also three stakeholder-developed alternatives also proposed and voted on. The PJM proposal only received a sector-weighted affirmative vote of 2.583 out of 5. P3 member companies actively participated in the stakeholder process. On September 1, 2022, the PJM Board met and directed PJM to submit the Tariff changes.

As an organization, P3 has consistently supported efforts to improve and enhance PJM's capacity market. The promise of the capacity market, allowing consumers to access the lowest priced capacity consistent with maintaining reliability, while sending the appropriate price signals for development and maintenance of long-term reliability investment, is a meaningful one that demands constant vigilance and evaluation. Properly structured capacity markets offer enormous value to consumers by meeting immediate load requirements while also recognizing the longer investment timeframes required to ensure future reliability.

P3 respectfully submits this protest to PJM's revisions, and urges the Commission reject PJM's Filing.

II. INTRODUCTION

PJM's capacity markets are in crisis, and approval of the PJM filing will only deepen that crisis and further challenge reliability issues in PJM. P3 implores the Commission to begin efforts to salvage PJM's capacity market and return it to a position of effectively providing a

market signal to invest in the necessary resources today in order to preserve reliability in PJM now and in the future. Rejecting the PJM filing is an appropriate place to start that process.

While capacity markets were established in PJM as a tool to ensure resource adequacy in future delivery years, a series of recent regulatory, policy and other changes counter any notion that the capacity market will send a signal to current investors seeking to invest at risk capital in assets that will deliver reliability at least cost. Changes to the Market Seller Offer Cap ("MSOC") have removed any independent judgement of asset owners to make decisions about the viability of their assets going forward. Changes to the Minimum Offer Price Rule ("MOPR") have effectively eliminated protections against the exercise of buyer market power, while the so-called protections against seller market power have gone to the extreme of having capacity offers effectively set by the PJM Independent Market Monitor. Other decisions related to the ORDC and the removal of the 10% adder from capacity market offers have served to compound the problem. The proposed changes to the VRR Curve continue a pattern of complete devaluation and corruption of a market established to compensate investment in long-term capacity resources.

The narrative that PJM has an over-procurement problem must end as PJM and neighboring power markets, are on the cusp of a reliability crisis if the Commission does not significantly adjust its view of the PJM capacity construct.[8] The inescapable reality is that PJM will be adding significant amounts of intermittent resources that will require significant flexible

[8] In addition to PJM's looming reliability challenges, when considering the purported "PJM over-procurement problem," the Commission should be mindful of the extent that MISO relies on PJM to meet its own reliability challenges (which are projected to grow over the next decade). PJM has shown that in future scenarios, MISO will be relying on up to 20 GW of capacity from PJM to meet its needs. https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx at 10-12. Also, New England ISO has also identified imports from the South as a means of meeting the future needs of the New England region. https://www.youtube.com/watch?v=1-sxL-zUnNw at 42 minutes.

and dispatchable resources to compliment the intermittent nature of wind and solar.[9] States within PJM that are promoting renewable energy, and rejecting fossil fuel generation, are not procuring an associated amount of energy storage or other dispatchable clean energy resources that could ensure the reliability of the system given their environmental policy objectives. Instead, they are relying on PJM to procure the needed reliability resources from private investors at least cost regardless of whether those resources are renewable or burn fossil fuels. Mandating the closure of certain existing facilities by certain dates and rejecting permitting applications for new fossil fuel generators in their own borders, certain states within PJM are relying on the addition of new fossil fuel generation in other PJM states to cover for their state policies that are hostile to reliability objectives.

The capacity market has been the long-established market mechanism in PJM for adding, retaining, and retiring capacity to ensure the reliability of the entire system. With that mechanism neutered by state policy goals, disparate contributions, and other market changes, PJM is faced with the prospect of continued retirements of baseload resources, increasing pressure on demand from data center proliferation, electric vehicles and all electric buildings, integration of intermittent resources, and no meaningful market signal for the unsubsidized resources required to enter the market that are objectively needed for reliability.

It is against this backdrop that the Commission must consider this filing and the continued deformation of RPM that it represents. At this crucial time, the Commission should take a deep breath and reflect upon the wisdom of taking additional, unnecessary, unsupported, short-sighted and likely short-lived steps to undermine PJM's capacity markets which have been

[9] *See*, https://pjm.com/-/media/committees-groups/committees/mc/2022/20220517-annual/item-06---renewable-integration-study-ris-20---presentation.ashx at 10 and https://pjm.com/-/media/documents/ferc/filings/2022/20221018-ad21-10-000.ashx.

undeniably devalued because of prior actions and decisions. Approval of PJM's filing will unnecessarily interject volatility into the PJM's capacity markets and increase the risk to reliable resources while denying the financial needs of the units that are and will be needed to support the PJM electrical system in the future.

PJM's capacity market is on life support right now and the Commission should be focused on reviving the patient – not injecting further injury.

III. PROTEST

A. A Properly Set VRR Curve is Essential to a Well-functioning Capacity Market.

As the Commission has recognized, "revenues from a well-designed and reliable capacity market are one important element supporting efficient private investment"[10] and the VRR curve is the foundation upon which the capacity market rests. The VRR curve is an administratively determined demand curve for PJM's reliability resources. The setting of the curve is based on the intersection of 1) the estimated amount of reserve capacity required to meet a defined reliability standard; and 2) a theoretical cost to construct new capacity that can meet that reliability requirement. From this starting point, other parameters are derived to establish the maximum price achievable, maximum and minimum amount that can be procured, and therefore the elasticity of demand (i.e., change in quantity given a change in price) along the curve. The VRR curve determines how capacity is ultimately valued.

[10] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, at P 77 (2006), order on reh'g, 119 FERC ¶ 61,318 (2007).

PJM uses the VRR curve in combination with the supply curve formed by capacity supplier sell offers submitted as part of an administratively organized procurement process to clear the RPM Auctions. PJM's Tariff defines the VRR curve as a set of lines connecting several price-quantity points that are stated as multiples or fractions of the Net Cost of New Entry, or Net CONE, reflected as $/MW-day (on the price axis) and a defined range around the target reliability requirement (on the megawatt quantity axis).

Historically, PJM and FERC have used the downward sloping demand curve as a tool to promote stability and reduced volatility in capacity prices.[11] As the Commission offered when it initially approved the sloping demand curve in PJM, "A downward-sloping demand curve would reduce capacity price volatility and increase the stability of the capacity revenue stream over time."[12] The Commission saw the value in capacity prices that change "gradually"[13] over time and well understood that volatility in capacity prices would erode the confidence that was essential to achieving the value necessary to meet the reliability objectives of the capacity market.

Ultimately, the Commission envisioned a market with "stable and predictable capacity revenues to generators over time, which will encourage more capacity to be built at more favorable terms."[14] The changes proposed in this filing must be evaluated with this goal in mind. Regrettably, PJM's proposal comes up short and sets the stage for the very volatility that

[11] Note that PJM prior to 2006 had a vertical demand curve that led to significant price volatility.

[12] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, at P 75 (2006), order on reh'g, 119 FERC ¶ 61,318 (2007) at P 26.

[13] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, at P 75 (2006),

[14] *Id.* at 78.

the Commission rightly sought to avoid, while effectively ignoring the fact that the reference resource cannot legally be built in a large portion of the PJM footprint as a result of state policies.

B. PJM's Proposal Is Not Just and Reasonable.

P3 agrees with Brattle in that the objective of the VRR curve is "to achieve PJM's resource adequacy targets through a competitive market with prices high enough to attract entry when needed, and low enough to foster efficient exit and retirements during surplus, while avoiding excessive volatility in either prices or quantities."[15] This goal has not changed since 2006 and remains valid today.

However, PJM's proposal is not consistent with this objective and, as submitted, represents a step backwards as it relates to PJM's capacity market. At a time when capacity revenues are becoming more important and less available to those same resources that are not running as frequently (and collecting energy market revenues) due to the increases in government-supported intermittent resources, PJM's proposal would further erode price signals and increase price volatility reducing the attractiveness of investing in PJM capacity resources. The changes will most likely lead to retirement price signals for resources that should be retained while starving existing unsubsidized resources that will be needed as the grid evolves.

Given the failure of market signals exacerbated by PJM's filing, capacity investors will likely seek subsidies to justify investments because market revenues will be insufficient, unpredictable, and ultimately unreliable as a basis for billions of dollars of new investment. With the lack of

[15] PJM Filing, Attachment C Affidavit of Kathleen Spees and Samuel A. Newell at P 8.

market signals for new investment, consumers will face a future of higher prices and reduced reliability as "around the market" solutions such as RMR contracts proliferate.[16] This is not the future that PJM, the Commission or the consumers of PJM should aspire to, but it is precisely that path the PJM's markets are on, and will continue down, if the Commission approves this filing.

C. Moving from a Historical EAS Calculation to Forward Looking Calculation Will Introduce Uncertainty and Volatility into the Market.

Predicting future energy prices is a fool's errand. While Brattle can contend that its forward-looking approach to estimate the EAS offset is "analytically rigorous" and used by their clients other than PJM, at the end of the day energy price futures are highly susceptible to and tend to magnify unpredictable events. As has been experienced, weather, natural disasters, foreign wars and global pandemics all cause dramatic changes in PJM's energy prices, natural gas prices, and trader expectations about future prices for these commodities. In 2018, PJM energy prices averaged $37.83/MWh. In 2020, they dipped to $21.65/MWh while this year they are at $77.78/MWh through August.[17] Financial trades to hedge physical delivery in future, trades settling for months out from when the actual commodity prices settled in physical markets, were even more dramatic. These price swings were caused by events that were not foreseeable three years prior to the delivery year.

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[16] The Commission should be ever mindful of the costs associated with RMR contracts and their impact on consumers - https://www.delawareonline.com/story/news/local/2022/08/03/coal-powered-indian-river-power-plant-shutdown-delayed/65384383007/. Moreover, the Commission has concluded that RMRs should be used as a tool of last resort because, "RMR contracts suppress market-clearing prices, increase uplift payments, and make it difficult for new generators to profitably enter the market." Devon Power LLC, 103 FERC ¶ 61,082, at P 29 (2003).

[17] *See,* https://pjm.com/-/media/committees-groups/committees/mc/2022/20220919-webinar/item-05a---market-operations-report.ashx at 6.

Moreover, as outlined by Ms. Tanya Bodell in the attached affidavit ("Attachment A – Tanya L. Bodell Affidavit"), moving to a forward-looking EAS as PJM proposes has major flaws that do not plague the historical calculation. A careful reading and understanding of the assumptions underlying the proposed forward-looking EAS offset methodology reveals that Brattle's "analytically rigorous" calculation is built on a flawed foundation. The futures prices that go into PJM's proposed EAS offset methodology to set the VRR curve more than three years into the future do not reflect a collective set of trader decisions and expectations regarding energy markets. Instead, those futures prices are based on projections using algorithms developed by one entity to extend futures prices out further than liquidity allows. These algorithmically-derived price projections are then put into another proprietary algorithm to project future dispatch and calculate net revenues for a reference unit. The reference unit is now proposed by PJM to be a combined cycle, which would be more dependent on the estimated net revenues for energy estimated by the algorithmic dispatch based on the algorithmically-estimated commodity prices that serve as the primary inputs. In effect, PJM's proposed methodology to calculate Net CONE is not an "analytically rigorous" analysis of anything, but rather an *estimate* using a new *estimation* methodology calculated, using a proprietary *estimation* tool, based on *estimates* of market prices generated by a proprietary algorithm.

Indeed, the PJM proposal for the forward-looking EAS offset methodology can be described in the same manner as Winston Churchill described Russia's foreign policy in 1939 – "It is a riddle, wrapped in a mystery, inside an enigma."[18] Clearly, this it is not the basis for just and reasonable rates.

[18] International Churchill Society, https://winstonchurchill.org/publications/finest-hour/finest-hour-150/churchill-on-russia/

The PJM proposal is severely flawed and cannot be considered just and reasonable. Among its many limitations:

1. **Future Energy Price Markets Lack Liquidity.** Liquidity in future energy markets is essential to effectively representing market expectations regarding future energy and natural gas prices. The necessary commodity market liquidity is simply not present in the period required to meet the RPM design specifications of holding auctions three years before the delivery year. As Ms. Bodell observes, futures contracts for the trading hubs that PJM proposes to use may be very liquidly traded a few months out, and somewhat liquidly-traded less than two years ahead, but certainly not the three and a half years that is required for purposes of setting Net CONE when there are often no trades or, at best, sporadic trading.[19] As recognized by Brattle, lack of liquidity renders the proposed approach inapplicable to the purpose for which the futures prices are being used – setting Net CONE. Even the proposed adjustment to derive pricing for illiquid markets is problematic due to illiquidity. Most "future prices" that PJM proposes to rely on for "liquidly-traded" markets are derived from an algorithm and are not actually what buyers and sellers are agreeing to. As such, PJM is relying upon approximations based on a proprietary algorithm that is not publicly-available – not actual market data – to develop its Net CONE values. The Commission should demand more confidence in the foundation for calculating the EAS offset rather than the future energy prices than the PJM filing proposes to rely upon, and ultimately should reject any claims that future

[19] *See,* Attachment A, Tanya L. Bodell Affidavit ("Bodell Affidavit") at ¶¶ 63 – 74.

energy markets in PJM are sufficiently liquid three and a half years ahead of the delivery year to provide the EAS offset estimate.

2. **Input Data is Not Publicly Available and Lacks Transparency**. As Ms. Bodell explains, the input data that PJM proposes to use to calculate future revenues depends on proprietary databases and models, which are not publicly available.[20] As currently structured, this information will not be available, and therefore, it will be challenging, if not impossible, for stakeholders (whether supply or load) to fully understand how future revenues are being calculated. The "black box" approach to such a critical component of future capacity market performance will inject needless uncertainty into decisions related to future investments in PJM.

3. **The Dispatch Model is Not Publicly Available and Lacks Transparency.** Compounding the problem of the data opacity is a dispatch model that is also proprietary and equally opaque. PJM proposes to use the PLEXOS dispatch model which, as Ms. Bodell explains, would require a market participant to purchase and be trained upon to access.[21] PLEXOS relies upon proprietary algorithms and inputs that are not available to the public, so in addition to PJM's data lacking transparency, how that data is used to calculate future prices is also done inside a black box.

[20] Bodell Affidavit at ¶ 98.

[21] Bodell Affidavit at ¶¶ 104 and 105.

4. **PJM Does Not Provide Sufficient Supporting Documentation.** In support of its proposed Net CONE values and EAS offset estimates, PJM provided a mere spreadsheet of the results. PJM does not and cannot provide the input prices that serve as the foundation for its calculation because they are proprietary. PJM does not and cannot provide the calculations for the pricing inputs derived from that proprietary data. PJM does not provide the pricing inputs that feed into the proprietary dispatch model. PJM does not and cannot provide the dispatch algorithm embedded in the proprietary model. PJM does not even provide the hourly dispatch results generated by the proprietary model. Nearly all entries on that spreadsheet are hard-coded preventing a clear understanding of the basis for the values used in PJM's calculations. PJM is proposing to make very significant and material changes to its capacity market but not providing nearly enough information to justify that departure from decades of precedent. If the approach was not so seriously flawed, all of the data required to perform a thorough review of the inputs, algorithms, and results should be made by PJM as part of the quadrennial review and in advance of each BRA to ensure valid results. As Ms. Bodell points out, such details have been provided in other Net CONE deliberations, and she would expect to have a defined set of information to test PJM's proposed inputs to the VRR curve. PJM's reliance on proprietary data and dispatch model, however, preclude such a sharing of information, and therefore violates FERC's philosophical foundation of transparency in organized electricity markets.[22]

[22] FERC has consistently recognized the importance of market transparency to improve market efficiency. For example, see 18 CFR Part 35, RM17-2-000; Order No. 844], *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators.* The Commission offered, "Current reporting practices regarding uplift and the reasons for making operator-initiated commitments do not provide adequate transparency for stakeholders to understand the needs of the system and recognize the resource attributes that are required to meet these needs."

As Ms. Bodell concludes, "In effect, by introducing short-term energy price conditions into the VRR Curve parameters, and magnifying the volatility with a proposed change to the combined cycle reference unit, PJM is fouling the purpose and incentives of the RPM."[23] While the calculation of EAS offset using historical prices can present volatility challenges as well, it is not uncertain. It includes averaging of three years of historical data to smooth out short-term volatility versus the proposed reliance on thirty trading days 180 days prior to the BRA. The current approach also is preferrable because it is objective, transparent and predictable, based on public data that PJM supplies. Both suppliers and buyers can manage expectations based on observable and accessible data. Moving from the stable and predictable historical calculation to the volatile and unpredictable approach, particularly given the failing health of PJM capacity markets in general, is unnecessary and unwise.

Another problem associated with the change to a forward-looking approximation of energy revenues is that, as PJM concedes, PJM will retain the historical looking calculation of energy revenues for purposes of setting a resource's Market Seller Offer Cap and MOPR Offer Floor Price.[24] PJM does not even attempt to explain the logic of having a VRR curve set by a forward-looking price methodology while having MSOCs and MOPR floor prices set by different energy market revenue offsets based on historical prices. It is hard to imagine that any well-grounded regulator could find such a market design just and reasonable and, tellingly, PJM does not even attempt to defend this undeniable and illogical result if the Commission were to approve PJM's filing.

[23] Bodell Affidavit at ¶ 192.

[24] PJM Filing at footnote 163.

The goal of the EAS mechanism is to predict future energy revenues three years forward as closely as possible to the actual results understanding that inevitably those predicted prices will be inaccurate to some degree. Critics of the historical offset will rightly point to calculations that were off in the delivery year; however, using futures prices will no doubt suffer likely worse discrepancies. Keeping in mind the goals of the capacity market, the Commission should focus on what is the most workable and reliable construct to serve as a basis for the projections. Historical calculations are based on publicly available data, easily calculated, an easily understood and a reasonable proxy for future prices, and avoid the numerous subjective and opaque determinations that the proposed forward-looking approach requires. Since 2006, the historical approach has brought a predictability and transparency that allow a higher degree of stability and enhance market confidence. What the Commission concluded in 2006 remains true today, "given the year-to-year volatility in both energy prices and fuel prices, an average of multiple recent years is more likely to be a good predictor of revenues three years forward."[25] Having such a "good predictor" in place remains as important today as it did in 2006.

D. The Change from a Combustion Turbine to a Combined Cycle Reference Unit Compounds the Problems Associated with the Forward-Looking EAS Offset.

In 2018, PJM clearly stated,

> "A CT is the appropriate reference resource for the capacity market design because it has the lowest capital cost, provides the shortest time to market, and derives the most significant portion of its revenue from the capacity market as compared to other resources. The fact that the CT receives the smallest amount of its revenue from the energy market means that its Net CONE value is the least likely to be significantly perturbed by potential changes in energy market prices. Thus, certainty is provided through the use of a peaking unit as reference resource because it minimizes the exposure to short-term energy revenue offset volatility. Also, PJM believes that maintaining the same technology type provides market stability and

[25] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, at P 119 (2006).

> avoids perceived opportunistic switching to units with more favorable economics in any given year. As well, providing certainty in reference technology promotes continued investment in PJM's capacity market. This reasoning is even more critical in the face of significant changes in the CONE detailed in the Brattle reports."[26]

P3 could not agree more, and PJM offers very little to no explanation as to what has changed in the four years since PJM made these declarations.[27]

In fact, PJM's current Vice President of Market Services, Adam Keech, in 2018 proposed an evaluation standard for the Commission. As he stated at the time, "So long as a CT plant remains an economic new entry option in the PJM Region, a CT-based Net CONE can still be consistent with the equilibrium Net CONE a reasonably designed VRR Curve is expected to produce."[28] He also stated at the time that PJM did not support changing to a CC "on an assumption that CT Plants no longer have a significant role to play in the PJM Region." [29]

Again, what has changed? Brattle has been consistent in its support of a CC. However, PJM is changing its position with little justification. Tellingly, neither Mr. Keech nor any other PJM employee submitted an affidavit supporting the instant filing. In 2018, two PJM executives, Mr. Keech and Gary Helm, PJM Lead Market Strategist, offered affidavits supporting the filing. There are only Brattle affidavits in PJM's 2022 filing.[30]

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[26] https://www.pjm.com/-/media/committees-groups/committees/mc/20180927/20180927-item-05-quadrennial-review-pjm-position.ashx

[27] It is worth nothing that the Commission agreed with PJM in 2019. "We agree that CT plants typically are built at a lower total cost than CC plants, and as a result, CTs typically can be deployed quickly to address any potential resource adequacy or reliability concerns. Furthermore, as PJM states, CT plants represent the generation technology that is most dependent on capacity market revenue due to their high marginal operating costs and low capacity factors." 167 FERC ¶ 61,029 at P 59.

[28] *PJM Interconnection, L.L.C.,* Docket No. ER19-105-000 (October 12, 2018) Attachment C Affidavit of Adam J. Keech at p. 3.

[29] *Id.*

Although ambiguous, PJM seems to rest its current desire to switch to a Combined Cycle on three primary reasons:

1. Combined cycles are less expensive (which is not what PJM contended in 2018);

2. Combined cycles are less susceptible to energy price fluctuations (which is false); and

3. Brattle recommends a Combined Cycle (Brattle recommended a Combined Cycle in 2018 and PJM and the Commission rejected that recommendation).

The Commission should demand more from PJM before making such a dramatic change to the capacity market. Four years ago, PJM was of the mind of CTs were the most economic reference resource, less susceptible to energy market fluctuations and a more appropriate reference unit. In light of other dynamics in the capacity market and the changes in state policy (discussed further below), it makes little sense to change to a different reference resource at this time, especially without a very developed explanation from PJM (not Brattle) as to its choice of the reference resource. PJM's filing is missing that critical explanation.

As such, P3 supports the retention of the Combustion Turbine reference unit. CT units will not be as dependent on energy market revenues (because they do not run as often) and, as such, the Net CONE used to produce the VRR Curve will not be subject to the energy market volatility that will impact CCs given that CCs run more than CT. Correspondingly, the Net CONE will remain consistent with the methodology PJM has been using since 2006, and will continue to offer the longer-term transparency and stability that RPM was originally designed to provide. Moreover, as the grid evolves to incorporate more intermittent resources, smaller and more nimble units are going to be required to meet the reliability demands of the system, which

between the reviewed reference unit choices, are better reflected in the form of gas-powered CTs.

When combined with the decision to move to a forward-looking energy offset, the decision to move from a CT to a CC is another ingredient in PJM's recipe for capacity market disaster. The CT is a logical and defensible reference resource that avoids many that challenges that are associated with the move to a CC (and a forward-looking EAS offset) described in this filing. The Commission should reject PJM's decision to change the reference resource at this time, in general, but especially in combination with the proposed change to the more volatile, less transparent and unpredictable forward-looking EAS offset methodology.

E. PJM's Proposed Changes to the VRR Curve Shape Will Further Challenge Capacity Market Signals.

Compounding the challenges associated with the proposed changes, PJM's proposed changes to the slope of the VRR will increase the likelihood of more dramatic year to year fluctuations in capacity prices. It is axiomatic and PJM concedes that steeper curves will lead to greater price volatility. PJM justifies increasing the steepness with changes to the EAS calculation and changes to the reference unit – both of which are flawed approaches – in order to narrow the potential amount of reliability that ultimately can be procured. Modifying the VRR Curve parameters in addition to proposing a combined cycle as the proposed reference unit and the forward-looking EAS offset adds a third way to increase volatility and compounds the price impact of the other changes. As Ms. Bodell concludes, "The combination of three major changes to the RPM market structure – combined cycle reference unit, change to a forward-looking E&AS Offset methodology with reliance on proprietary futures prices, and steepened VRR Curve – increase

both uncertainty and volatility in the Net CONE, VRR Curve shape, and RPM market clearing prices."[31]

. The combination of the proposed changes appears to be designed to increase capacity market price volatility. Given the purported claim that there is excess generation capacity in PJM, perhaps the proposed changes are an attempt to send more volatility into capacity market prices in order to delay new entry and motivate retirement of the least economic units on the system. If that is PJM's justification for the proposed changes to the VRR curve, each of which serve to increase capacity market price volatility and compound that volatility when implemented together, then that justification flies in the face of the objectives of providing a stable price signal for long-term investment in reliability. Furthermore, injecting the level of price volatility these changes generate, all at once and without analysis of the impact of how such volatility may generate mass retirements on the system or in recognition of the financial impact on private investment that already has occurred, is unjust and unreasonable and completely counter to concerns about resource adequacy challenges in PJM. Simply claiming, as PJM does, that their analysis concludes that reliability will not be impacted – possibly informed by only the narrower band around the targeted reliability levels – is insufficient given the magnitude of the proposed changes.[32] In reality, the only way PJM can conclude that reliability will not be impacted is by having the option to enter into must-run contracts, as needed. This is not a way to structure a just and reasonable competitive wholesale electricity market.

[31] Bodell Affidavit at P ¶ 13.

[32] PJM has also alerted the Commission to future reliability challenges given the evolving capacity mix. See, https://pjm.com/-/media/documents/ferc/filings/2022/20221018-ad21-10-000.ashx

F. PJM Should Be Transitioning to a Reference Unit that Can Be Actually Permitted and Built in PJM.

Finally, and importantly, PJM and the Commission cannot ignore the reality that states in the PJM footprint are actively pursuing policies to limit and/or close combustion generators. PJM and Brattle recognize what is happening at the state level; however, they elect to move past this reality as if it were not happening or is too challenging to address. The Commission should not adopt a similar posture. Consider:

- In Illinois, Climate and Equitable Jobs Act (CEJA) mandates phased retirement for all fossil units in the state no later than 2045. Given that a new combustion turbine in Illinois would be required to shut down within 20 years (or less) of opening, it is virtually certain that a new combined cycle will not be supported by capacity market pricing.
- In New Jersey, the Energy Master Plan places New Jersey on path to 100% clean energy by 2050 and the New Jersey DEP is actively evaluating aggressive carbon limitations on all generating facilities in the state that could lead to closure of certain facilities.[33]
- In Virginia, the Virginia Clean Energy Economy Act (VECA), signed into law in 2020, forces the retirement of all natural gas plants in the state by 2045 in Dominion's

[33] In response to measures to meet New Jersey Governor Phil Murphy's climate change goals of Executive Order 100, on December 6, 2021, the New Jersey Department of Environmental Protection (NJDEP) published a proposed new rule regarding the control and prohibition of carbon dioxide (CO_2) emissions. The proposed rule sets CO_2 emissions limits that continue to lower over time for large fossil fuel-fired electric generating units (EGUs). These are defined as EGUs with a nameplate capacity equal to or greater than 25-megawatt electric (MWe). There are three proposed tiers existing EGUs must meet: With a proposed compliance date of January 1, 2024, the rule sets the first-tier emissions limit at 1,700 pounds (lb) of CO_2 per megawatt hour (MWh) of the EGU's gross energy output (1,700 lb/MWh). The second-tier compliance date of January 1, 2027, sets an emissions limit of 1,300 lb/MWh. The final tier sets the emissions limit at 1,000 lb/MWh, with a proposed compliance date of 2035.

service territory and 2050 in AEP's serve territory.[34] As the recently released Virginia Energy Plan observed, "Under the VCEA, Virginia is legally required to retire all baseload generation, except for incumbent nuclear power plants, in favor of intermittent renewable generation."[35]

Given these state policies in several large PJM states, it defies logic for PJM to suggest to the Commission that these polices can only be reconciled as "one offs."[36] While "current generation development trends" may be able to point to the construction of combined cycle units in the PJM footprint, moving to a reference resource that cannot be built in several major PJM states runs counter to PJM's mandate and the objectives of the VRR curve. Among the criteria that PJM must consider when selecting the reference resource is whether, "project developers will likely build a resource using the reference technology."[37] As it relates to combined cycles in Virginia, New Jersey, and Illinois, it is fair to say that no project developers would be considering such a project given the limitations of current state policy.

As a result of these documented changes to state policy that have occurred since the last quadrennial review, PJM will likely need to move to a zero-carbon reference unit in the form of either a storage resource, a solar resource with battery backup or a combustion resource with

[34] *See,* https://lis.virginia.gov/cgi-bin/legp604.exe?ses=201&typ=bil&val=hb1526 and https://www.virginiamercury.com/2020/02/20/ten-things-to-know-about-the-clean-economy-act/ and https://energy.virginia.gov/energy-efficiency/documents/2022_Virginia_Energy_Plan.pdf

[35] *See,* https://energy.virginia.gov/energy-efficiency/documents/2022_Virginia_Energy_Plan.pdf at 7.

[36] PJM Filing at pp. 30-31.

[37] ISO New England, 147 FERC ¶ 61,173, at P 15.

carbon sequestration, at least for some of the zones.[38] None of these options were found to be viable reference unit resources at the moment, but four years from now, the technology could be in a position to support such a transition – especially in light of new, significant federal incentives. Moreover, if PJM starts now, it can appropriately consider the inputs and dynamics associated with each technology. Knowing the direction state and federal policies are forcing capacity development, it makes little sense to change the reference unit knowing that in four years the reference unit will likely change yet again. Having three different reference units in the span of less than 10 years is again counter to the notion that capacity markets should be a stable source of revenue for units that are necessary to preserve reliability.

IV. CONCLUSION

Given the numerous troubling flaws associated with the PJM filing, the Commission should reject the filing. P3 respectfully submits that the goals of the VRR curve, and by extension the capacity market, will be better achieved by maintaining the current VRR curve shape, the current methodology for calculating EAS revenue that uses actual, publicly-available and transparent historical clearing prices, and the current reference technology of a combustion turbine. P3 appreciates that potentially as soon as the next VRR reset, dramatic changes to the reference technology may be appropriate in order to reflect state policies and permitting limitations. However, for purposes of the current filing, significant and material changes are likely to be short lived. Commission approval will only introduce uncertainty and volatility at a time when the capacity construct in PJM is already severely compromised. Now is exactly the wrong time to go down the path PJM suggests. Introducing yet more instability now – and as

[38] Brattle did not model any potential reference resources with carbon sequestration capabilities.

incorporated into future BRAs if PJM's proposed methodologies are adopted – would be imprudent. Instead, the Commission should simply reject PJM's proposal, allow the current parameters to continue and instruct PJM to begin the process of moving to a zero-carbon reference resource for delivery years 2030 and beyond.

Respectfully submitted,

On behalf of The PJM Power Providers Group

By*: Glen Thomas*
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610-768-8080

October 21, 2022

CERTIFICATE OF SERVICE

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

Dated at Washington DC, this 21st day of October, 2022.

On behalf of The PJM Power Providers Group

By: *Diane Slifer*
Diane Slifer
GT Power Group
101 Lindenwood Drive, Suite 225
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610-768-8080

Attachment A

Affidavit
Tanya L. Bodell

UNITED STATES OF AMERICA

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	**Docket No. ER22-2984-000**
	)	

AFFIDAVIT OF
TANYA L. BODELL
ON BEHALF OF PJM POWER PROVIDERS GROUP

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AFFIDAVIT OF TANYA L. BODELL

ON BEHALF OF PJM POWER PROVIDERS GROUP

I. INTRODUCTION

1. My name is Tanya L. Bodell. I am a Partner at StoneTurn Group LLC, a global advisory firm that assists companies, their counsel and government agencies on regulatory, risk and compliance issues, investigations and business disputes. StoneTurn has 15 global offices across five continents. I am based in the office located in Boston, Massachusetts.

2. At StoneTurn, I provide advisory services to clients, advising on business strategy and investment decisions. Analytical service offerings include energy market assessments, long-term price projections using fundamental and stochastic analyses to create a distribution of potential outcomes and risk assessments to inform client decisions. I also oversee asset valuation and have prepared independent appraisals for a number of different types of energy assets, including power plants. I have performed solvency analyses for companies and financial assets that have declared bankruptcy and managed competitive procurements for energy supply. I have analyzed large energy trade books for various assignments, including for purposes of valuation, estimating damages, determining solvency, assessing mark-to-market pricing, and identifying improper trades (e.g., wash trades and round-trip trades).

3. In my roles as the Executive Director of Energyzt and Managing Director at FTI Consulting, I was responsible for overseeing the development and maintenance of the power market models and the quantitative analysis of industry data that allow clients to make informed investment decisions.

4. I have been a consultant for more than twenty-five years, providing business advice and expert support to market participants, regulators and policy makers in the energy industry in general and the power sector in particular. Prior to joining StoneTurn in 2022, I founded Energyzt in 2012, where I continue to serve as Executive Director. Prior to Energyzt, I was a Managing Director and founder of the Electricity Consulting Group at FTI Consulting. Prior to FTI, I was a Vice President in the Energy and Environment practice at Charles River Associates, a company I joined in 2000. Prior to that, I was a consultant at Putnam, Hayes & Bartlett which subsequently merged with Hagler Bailly to become PHB Hagler Bailly before being acquired by PA Consulting. My role at each of these firms served clients in the power sector as well as other industries.

5. I received a B.A. in mathematical economics from Pomona College, an M.A. in public policy from the Harris School of Public Policy at the University of Chicago, and an M.B.A. from the Massachusetts Institute of Technology Sloan School of Management as a Sloan Fellow.

6. I have submitted testimony to the Federal Energy Regulatory Commission ("Commission") in five prior dockets:

    a. **Docket No. ER21-669-000 – Morongo Transmission LLC,** In 2020, on behalf of Morongo Transmission LLC, submitted expert testimony to the Commission regarding the differential risks of their share of a transmission project over existing rights of way in Southern California.

    b. **Docket No. ER19-1428-000 – ISO-New England Net CONE Proceeding:** In 2019, on behalf of NRG Power Marketing, LLC, I submitted expert testimony to the Commission regarding the ISO-NE proposal to provide interim compensation for generation resources with inventoried fuel.

    c. **Docket No. ER19-105-000 – PJM Interconnection:** In 2018, on behalf of the PJM Power Providers Group, I submitted expert testimony to the Commission in response to PJM's submission for the fourth quadrennial review.

    d. **Docket No. ER17-795-000 – ISO-New England Net CONE Proceeding:** In 2018, on behalf of the New England Power Generators Association, I submitted expert testimony and surrebuttal testimony to the Commission regarding key aspects of the ISO New England Net CONE submission.

    e. **Docket No. ER11-2909-004 – Triennial rate review of Atlantic Path 15, LLC.:** In 2011, on behalf of Atlantic Path 15, LLC, I submitted testimony estimating the benefits of a transmission upgrade using a production cost model to project locational marginal prices in the CAISO market with and without the upgrade (Docket No. ER11-2909-004).

7. I also have testified as an expert witness in a number of other matters before state public utility commissions, arbitration panels and courts of law.

8. My detailed *curriculum vitae* is incorporated herein as Exhibit No. 1.

II. PURPOSE OF AFFIDAVIT

9. The purpose of this affidavit is to provide relevant facts regarding the implications of PJM's proposed changes to parameters and methodology for the assumed demand curve that would be incorporated into the Reliability Pricing Model "RPM" for delivery year 2026/27, continuing until the next quadrennial review takes effect.

10. In its filing, PJM proposes a series of new parameters and methodology for the demand curve to be assumed in RPM auctions starting in 2026/27. Specifically, these changes include:

a. **Forward E&AS Estimate:** PJM proposes to estimate the E&AS Offset using a forward-looking methodology that runs a proprietary market model to perform 24-hour dispatch of a reference unit based on a 30-day average of proprietary futures prices for the delivery period posted 180 days prior to the start of Base Residual Auction ("BRA");

b. **Reference Unit:** A combined cycle would be used as the reference unit versus a combustion turbine as is currently adopted and historically has been used; and

c. **VRR Curve Parameter Changes:** Proposed changes to VRR Curve parameters relocate defining points of the demand curve at the minimum and maximum points of the curve.

11. Informing PJM's proposal,[1] the Brattle Group ("Brattle") presented an affidavit with recommendations concerning the technology that should be adopted for the reference unit along with calculations of the cost of new entry ("CONE") and Net CONE (i.e., CONE less an estimate of energy and ancillary services net revenue ("E&AS Offset")).[2] Brattle also provided an affidavit recommending the forward-looking methodology for calculating the E&AS Offset[3] and an analysis supporting PJM's proposal to modify the VRR Curve structure.[4]

12. During the course of the quadrennial review, the Independent Market Monitor ("IMM") provided its own estimates of CONE and Net CONE using alternative technologies as the reference unit and E&AS estimation methodologies. Those are referenced within the body of this affidavit to illustrate the implications of adopting PJM's proposed changes using a third-party's calculations, in addition to my own analysis.

13. PJM's filing serves to increase uncertainty and volatility surrounding the Net CONE values, and therefore the VRR Curve and market clearing price, from year to year. These two factors are distinct:

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[1] Wright & Talisman, Letter to Honorable Kimberly D. Bose, Federal Energy Regulatory Commission, PJM Interconnection, L.L.C., Docket No. ER22-___-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, September 30, 2022, ("PJM Filing Cover Letter").

[2] Before the Federal Energy Regulatory Commission, PJM Interconnection, L.L.C., Docket No. ER22-___-000, Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. ("Brattle/S&L CONE Affidavit")

[3] Before the Federal Energy Regulatory Commission, PJM Interconnection, L.L.C., Docket No. ER22-___-000, Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. ("Brattle EAS Affidavit").

[4] Before the Federal Energy Regulatory Commission, PJM Interconnection, L.L.C., Docket No. ER22-___-000, Affidavit of Kathleen Spees and Samuel A. Newell on Behalf of PJM Interconnection, L.L.C. ("VRR Curve Affidavit").

a. **Uncertainty:** Uncertainty arises from the unknown inputs and methodologies on which the forward-looking E&AS Offset relies. The proposed methodology depends on (i) non-public proprietary data that is based on price projection algorithms during periods of illiquidity; and (ii) a proprietary dispatch model that incorporates confidential algorithms developed by PLEXOS. Reliance on proprietary information to calculate the E&AS Offset decreases transparency and increases market uncertainty. This creates uncertainty in addition to uncertainty around Gross CONE estimates.

b. **Volatility:** PJM's recommendation to adopt a combined cycle for the reference unit increases the influence of projected energy market revenues into the Net CONE calculation. Volatility in short-term energy markets is incorporated directly into the E&AS Offset because it relies on price data which reflect short-term energy market conditions. Increased price volatility also occurs due to PJM's recommended changes to adopt the forward-looking methodology which removes many of the smoothing functions embedded in the historical methodology. Proposed changes to the VRR Curve all serve to steepen the VRR Curve, resulting in greater RPM price volatility.

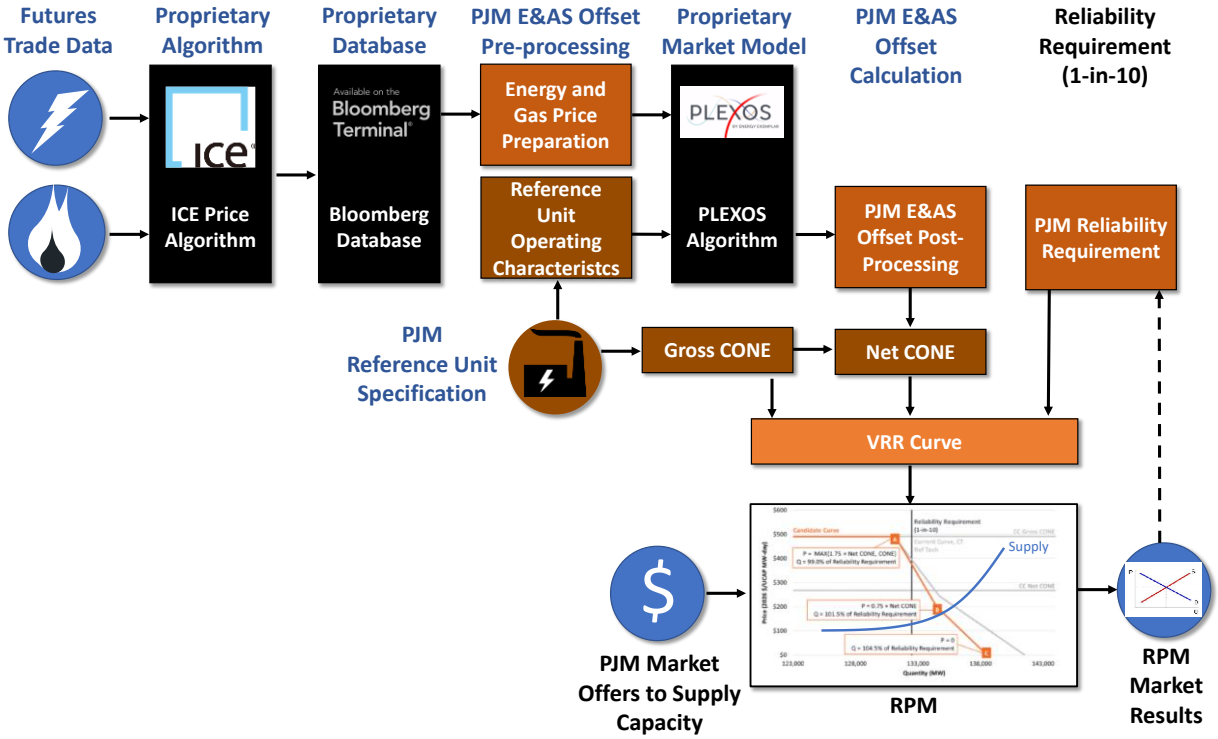
c. **Uncertainty and Volatility:** When combined, PJM's recommendations compound the problems of uncertainty and volatility. The forward-looking E&AS Offset relies on thirty trade days of futures prices generated by a proprietary algorithm versus the three-year average of historical short-term energy prices, increasing both uncertainty and volatility in the E&AS Offset calculation.

The combination of three major changes to the RPM market structure -- combined cycle reference unit, change to a forward-looking E&AS Offset methodology with reliance on proprietary futures prices, and steepened VRR Curve -- increase both uncertainty and volatility in the Net CONE, VRR Curve shape, and RPM market clearing prices.

14. **Figure *1*** illustrates how each of these proposed changes (blue text) to the market rules plus the supporting components and proprietary "black box" algorithms, flow through the PJM VRR Curve process to generate prices and quantities cleared by the RPM. The proposed forward-looking E&AS Offset methodology proposed by PJM as implemented by Brattle includes reliance on three proprietary sources that are not currently required under the historical E&AS Offset methodology.

15. The flow diagram illustrates the significance of these changes to the RPM market design. Any one of the proposed modifications would be a substantial change. Given that each of the changes move the market towards increased price volatility, there is a compounding impact. PJM's proposed changes therefore increase uncertainty and volatility regarding future capacity market revenues for market participants from one annual auction to the next.

Figure 1: Illustration of how PJM's proposed changes flow to RPM market results



16. My testimony addresses the impacts of the proposed changes on the RPM market and why the new RPM market design is antithetical to the objectives of the RPM.

17. Based on information provided as part of the quadrennial review and analyses described in this affidavit, I conclude that PJM's proposed changes in its filing individually and combined lead to:

    a. Greater uncertainty due to the proprietary nature of key inputs and algorithms required by the forward-looking E&AS Offset methodology;

    b. Increased RPM price volatility due to the steeper demand curve and the proposed combined cycle reference unit versus a combustion turbine;

    c. Greater influence of short-term energy price volatility into the VRR Curve parameters due to a combined cycle reference unit, forward-looking E&AS Offset methodology, and modified VRR Curve parameters;

    d. Magnification of perverse market price incentives that decrease RPM prices when additional capacity is required, and

    e. Violation of the objectives underlying the market construct to provide stable incentives to procure long-term capacity.

18. A summary of the basis for my conclusions is as follows:

a. **PJM's proposed forwarding-looking approach is not based on publicly-available data or software, relies on confidential algorithms, and therefore is not transparent and increases uncertainty.** The forward-looking approach generally adopts the proposed methodology previously presented by PJM to Commission. The input data sources rely on proprietary data collected by the Intercontinental Exchange ("ICE"), which Brattle claims is available from the Bloomberg proprietary data service, and uses a proprietary market model ("PLEXOS"), none of which are publicly-available.[5] Although the approach may be described in detail, it is not replicable without access to the specific inputs and model run outputs, which PJM failed to provide in sufficient detail to support its calculations. Furthermore, the futures prices that are critical to the forward-looking approach are not liquidly-traded far enough out to support calculations for a BRA scheduled more than 2 years in advance of the delivery period. Liquidity is a pre-requisite asserted during the original presentation of the proposed forward-looking approach and reiterated by Brattle.[6] The problem is that none of the proposed PJM energy hubs or natural gas delivery points that service PJM's generators are liquid enough to preclude reliance on the ICE proprietary futures price algorithm. Use of settlement prices are not based on actual trades executed during the 30 trade days, but on a proprietary ICE algorithm which may only incorporate trade data if trades occurred. The forward-looking E&AS estimation approach is an inappropriate methodology to adopt for RPM.

b. **The proposed combined cycle reference unit, alone and combined with the forward-looking E&AS calculation methodology, increases RPM price volatility.** The significant E&AS Offset for the combined cycle reference unit magnifies RPM price volatility and uncertainty associated with using PJM's proposed forward-looking methodology. The forward-looking methodology relies on futures prices for the BRA delivery period as they were traded during a 30-day period ending 180 days in advance of the BRA. This makes input prices into the dispatch model dependent on short-term pricing conditions that occurred during a limited trading period. Given the significantly higher E&AS Offset for a combined cycle that is dispatched more frequently than a combustion turbine, and elimination of the E&AS Offset price smoothing functions in the historical approach, volatility tied to futures markets creates greater volatility for Net CONE estimates used to set the VRR Curve parameters and RPM market clearing prices.

[5] For purposes of this affidavit, I rely on the definition of "publicly-available information" as defined by 17 CFR 160.3, Legal Information Institute, https://www.law.cornell.edu/cfr/text/17/160.3

[6] Brattle EAS Affidavit, ¶ 20-24.

c. **PJM's changes to other VRR Curve parameters steepen the VRR Curve and aggravate the impact of the new reference unit and new E&AS Offset methodology, increasing RPM Prices volatility.** In addition to the changes PJM proposes to make to the reference unit and E&AS Offset methodology, there are a number of other parameter modifications proposed in the PJM filing. These other changes to the RPM demand curve parameters change the shape and location of the VRR Curve, making it steeper. The steepening of the VRR Curve results in higher volatility for RPM prices. These changes also compound the volatility and uncertainty surrounding the impact of the reference unit and Net CONE calculation modifications.

d. **PJM's proposed changes result in perverse price incentives and are antithetical to an underlying objective of RPM.** The objective of RPM is to procure reliability by incentivizing long-term capital investment through stable price signals. Whereas capacity is meant to be procured over a longer-term investment horizon, PJM's proposed approach increases the influence of short-term energy market price volatility into the VRR Curve. This change creates perverse pricing incentives. When energy spark spreads increase due to a shortage in capacity, the proposed RPM design would decrease prices and quantity; when energy spark spreads decrease in response to excess supply, the VRR Curve would shift right and procure more capacity at a higher price. PJM's intent for RPM to add "stability and a locational nature to the pricing signal [that] provides forward investment signals"[7] is thwarted by the proposed changes.

III. PJM'S PROPOSED FORWARD-LOOKING APPROACH IS NOT TRANSPARENT

19. PJM proposes to adopt a new methodology for estimating the E&AS Offset based on a forward-looking approach versus the historical price methodology that will continue to be used through the 2025/2026 delivery period.

20. The historical price methodology consists of the following approach:

a. Obtain three years of historical PJM hourly price data.

b. Obtain three years of historical natural gas price data.

c. Assume the reference unit will be dispatched during a fixed amount of peak hours when economical.

[7] PJM, Reliability Pricing Model (RPM), Interconnection Training Program Module EM7, Winter 2011, p. 3, https://pjm.com/~/media/training/nerc-certifications/em7-RPM.ashx

d. Run the dispatch across three separate simulations using the three different years of historical pricing.

e. Average the revenue results from the three runs.

f. Subtract the estimated natural gas consumption cost from estimated revenues to generate net energy revenues.

g. Add in ancillary service revenues using assumed values.

21. By using an average of three years of historical price data, limiting the energy dispatch to peak hours, and fixing the assumed quantity of ancillary services, the historical methodology creates a more stable estimate of the E&AS Offset that is required to obtain Net CONE.

22. From an economic perspective, the historical E&AS Offset methodology continues to be a valid estimation technique. In contrast, for the reasons elaborated in this affidavit, the forward-looking E&AS Offset methodology includes serious flaws, the impact of which are compounded by adopting a combined cycle reference unit.

23. PJM's proposal adopts the Brattle recommendation to use effectively the same forward-looking pricing methodology that was submitted to the Commission in 2020, with an adjustment to: (i) eliminate the regulation services offset; (ii) switch the gas hub from Columbia-App TCO to MichCon; and (iii) a few changes in minor assumptions.

24. The forward-looking E&AS Offset methodology is more complex than the historical E&AS price methodology. The forward-looking E&AS Offset methodology consists of the following steps:

a. Obtain 30 consecutive trading days of electrical energy futures data for key PJM liquid hubs 180 days before the start of the scheduled auction.

b. Average the monthly energy futures prices for the BRA delivery months reported for those 30 trade days.

c. Shape monthly futures price averages into three sets of hourly energy prices using historical hourly energy prices from the three consecutive years prior to the determination of the RPM auction prices.

d. Add an additional step for shaping non-liquid hubs (which effectively adds a basis to liquid hub prices based on a defined algorithm.

e. Obtain 30 consecutive trading days of natural gas price futures data for key PJM liquid natural gas delivery points ending 180 days before the start of the scheduled auction.

f. Average the monthly natural gas futures prices reported for those 30 trade days.

g. Shape monthly averages into three sets of daily natural gas prices based on three separate consecutive calendar years corresponding to the three historical hourly energy price shapes.

h. Add an additional step for shaping non-liquid hubs (which effectively adds a basis to liquid hub prices based on a defined algorithm).

i. Obtain historical ancillary services prices from three consecutive calendar years prior to the determination of the RPM auction.

j. Shape historical real-time ancillary service market clearing prices by the ratio of forward real-time energy prices to the historical real-time LMP.

k. License the PLEXOS dispatch model and set up the PLEXOS model to operate in generator optimization mode.

l. Enter into PLEXOS the specifications of the reference unit.

m. Run the optimized dispatch program with the futures data shaped using historical prices and historical ancillary services data using the three sets of input prices.

n. Obtain three sets of net revenues from the PLEXOS runs.

o. Average the three years of net revenues to obtain an E&AS Offset estimate.

25. Brattle recommends adopting the forward-looking approach to estimate the E&AS Offset starting with the 2026/27 BRA. Adoption of the forward-looking E&AS Offset methodology is inappropriate for the following reasons.

a. **Lack of Liquidity:** The forward-looking approach requires liquidly-traded futures, which generally do not extend as far as the normal three-year forward auction schedule to which PJM has indicated it would revert by May 2024.[8]

b. **Input Data is Not Publicly-Available:** The input data relies on futures prices that are not publicly available, and must be procured through a proprietary data source such as Bloomberg (used by Brattle) or directly from ICE.

c. **The Dispatch Model is Not Publicly-Available:** The dispatch methodology relies on PLEXOS, a production cost model that is not publicly-available, but must be licensed and staff trained on how to operate the model.

d. **PJM Does Not Provide Sufficient Supporting Documentation for Transparency and Replication:** The underlying data provided by PJM in

[8] PJM, https://insidelines.pjm.com/pjm-compliance-filing-proposes-new-capacity-auction-timelines/

support of the Brattle calculations using the forward pricing methodology is inadequate to replicate or fully understand the inputs, assumptions, and algorithms.

Therefore, PJM's proposed approach is not transparent. Without the proprietary licenses to the data and the model, it is not replicable. Each of these points are elaborated upon below.

III.1 The futures contracts do not have sufficient liquidity and rely on algorithms

26. Although the Commission had approved PJM's adoption of the forward-looking approach, that approval had been granted when the period between the BRA and delivery was less than two years away from the trade dates. Beyond two years, futures at the PJM hubs and natural gas delivery points are not liquidly traded.

27. Brattle recognizes the importance of price data based on liquidly-traded hubs and recommends that only hubs that are liquidly-traded out to the BRA delivery period be used.[9] For illiquid hubs, an adjustment mechanism is proposed to apply to prices derived from a liquidly-traded hub.[10]

28. When using futures data as a forward-looking price projection, the importance of liquidity is critical to price transparency and the validity of the approach. If a hub is not liquidly-traded, the price does not necessarily reflect a robust market-based assessment of future fundamentals or the market's opinion of where prices should be traded for delivery at a future point in time. Lack of liquidity renders the proposed approach inapplicable to the purpose for which the futures prices are being used – namely to calculate Net CONE. Lack of liquidity disassociates prices from market conditions, thereby generating unjust and unreasonable rates.

29. Unlike globally-traded commodities such as oil indices that may be liquidly-traded out a decade or more, domestic natural gas hubs tend to be liquid for only a few years. Locational electricity hubs are even less liquidly-traded, tending to serve as short-term hedges with liquidity barely going out to a year or two. Futures contracts for the hubs identified in the forward-looking E&AS Offset methodology may be very liquid only a few months out from the trade date, with a more limited number of trades going out beyond a year.

III.1.1 Open interest is an incorrect liquidity measure for the E&AS Offset

30. Brattle uses open interest to claim that there is sufficient liquidity to calculate the forward-looking E&AS Offset using futures data.

[9] Brattle EAS Affidavit, ¶ 20-24.
[10] Brattle EAS Affidavit, ¶ 35.

> Further, we use the open interest in these contracts as our indicator of liquidity. Open interest refers to the number of contracts that are "open" (that is, remain outstanding) at the end of the trading day.[11]

For the reasons discussed below, open interest is not an appropriate measure of liquidity for purposes of assessing the validity of the E&AS Offset methodology.

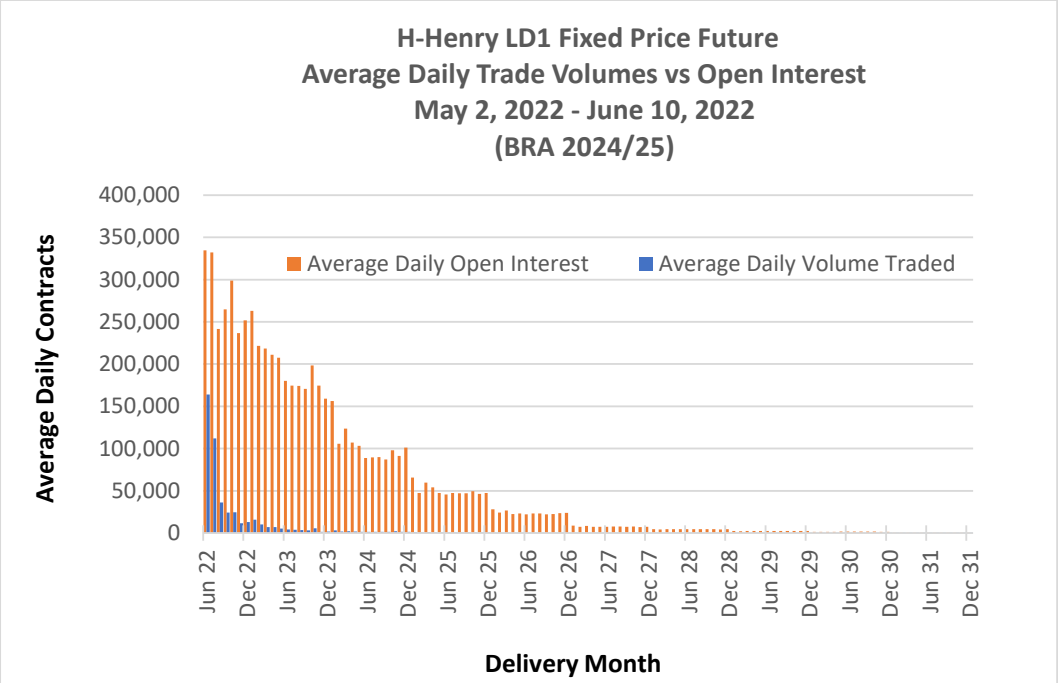
31. Open interest for a given month reflects active (i.e., "open") contracts that have a delivery period that includes that month and are ready to be traded. Open interest and changes in open interest from one trade day to the next reflects overall market activity in an asset and can be considered one measure of liquidity. This measure of liquidity, however, is not applicable to the E&AS Offset methodology.

32. The problem with applying open interest as the measure of liquidity to support the forward-looking E&AS Offset methodology is that active contracts reported for a given trade day reflects transactions that occurred outside of that trade day. Therefore, open interest contracts would not be consistent with measuring liquidity during the 30 consecutive trade dates 180 days before the BRA auction date on which the forward-looking E&AS Offset methodology depends.

33. **Figure 2** illustrates the difference between average daily open interest and average daily trades for a representative thirty trade day period at Henry Hub.[12]

[11] Brattle EAS Affidavit, ¶ 20.
[12] The thirty days represents the period that would be used for the forward-looking E&AS Offset estimate if applied to the 2024/25 RPM delivery period.

Figure 2: Comparison of Open Interest to Volumes Transacted at Henry Hub

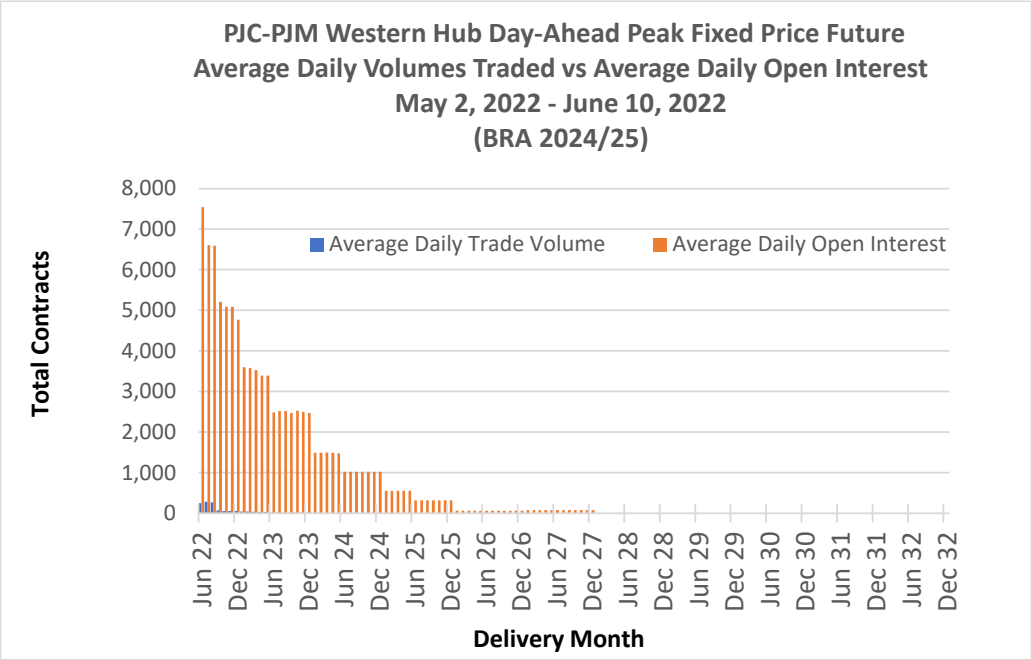


34. Henry Hub is among the most liquidly-traded natural gas futures markets in the U.S.. Any natural gas delivery hub in PJM would be less liquidly traded.

35. For this period, average daily trade volume is around half of the open interest in the most liquidly-traded one-month contract. For delivery more than a few months out, the number of trades drop significantly and are a very small percentage of the number of trades reported in open interest.

36. **Figure 3** illustrates the difference between open interest and volumes transacted at PJM West during the 30-day trading period that would be prescribed by the forward-looking E&AS Offset methodology if the forward-looking approach were applied to the 2024/2025 BRA scheduled for November 2022. Trade dates for the 2026/27 period have not yet arrived and therefore cannot be used in this analysis. This 30-day period is a representative example of the lack of liquidity in the financial markets that PJM intends to rely upon in estimating an E&AS Offset under the proposed methodology.

Figure 3: Comparison of Open Interest to Volumes Transacted at PJM West



37. Average daily open interest is well above the very small number of contracts actually traded in the period that supposedly represent the settlement price for that trade day.

38. For PJM, average daily traded volume for the month ahead for the 30-day trading period is less than 5 percent of the average daily open interest for the PJM Western Hub. The low percentage of trade volumes to open interest is another indication of the lack of liquidity in PJM's energy hubs.

39. Use of open interest, therefore, is not an appropriate measure of liquidity during the trade dates used in the forward-looking E&AS Offset methodology. Open interest does not measure how many contracts were traded on a given trade day and how many actual transactions will be generating the E&AS Offset price data used in the dispatch model.

40. In addition, most of the open interest for the 30-day period analyzed are block trades, as illustrated by the step-down block pattern of the average daily open interest, confirmed by our analysis of the ICE block volumes reported for those trade dates. According to the ICE Manual,

> A block trade is a permissible, off-exchange, privately negotiated transaction either at or exceeding an Exchange determined minimum threshold quantity of futures or options contracts which is executed at a fair and reasonable price apart and away from the central limit order book.[13]

[13] ICE Futures U.S., Block Trade – FAQs, paragraph 1, https://www.theice.com/publicdocs/futures_us/exchange_notices/Block_Trade_FAQ.pdf

> Given that these trades are executed off the exchange and outside of the central limit order book, they are likely to represent pricing for higher volume, longer-term bilateral trades and would not reflect pricing for net energy revenues available to generators through liquid, centralized, spot-market energy dispatch.

41. Finally, the settlement price proposed to be used in the VRR Curve is not the average price of the open contracts represented by open interest.

42. Therefore, Brattle's assessment of liquidity is an inappropriate metric for justifying application of the E&AS Offset methodology.

III.1.2 Volumes traded is a better indicator of liquidity for the E&AS Offset

43. Brattle references trade volumes in addition to open interest, but fails to make a showing of liquidity using traded volumes:

> We use open interest as an indicator of market liquidity for two reasons. First, the greater the open interest, **the greater the amount of trading** in the contract and thus the better the information revelation of market prices, other things being equal. Second, greater open interest and **contract trade volumes** reduce the chances that market prices can be manipulated successfully.

(emphasis added).[14]

44. Brattle does not include any measure of the amount of trading or trade volumes in their affidavits.

45. Under PJM's proposed methodology, the settlement price for 30 consecutive trading days performed 180 days before the scheduled BRA is to be used in the calculation of the E&AS Offset. To the extent there were multiple trades that day reflective of a liquidly-traded market, that settlement price could reflect the sentiment of the market on that trade day. If there were no trades, there normally would be no settlement price (other than an algorithmic representation).

46. Given the reliance on settlement prices, volumes traded on trade days for delivery during a month in the BRA delivery period is the proper measure of liquidity for the purposes of the E&AS Offset methodology.

47. Daily volumes indicate if a contract is liquidly traded. If a contract is not traded regularly and on a daily basis, it generally would not be considered liquid using volume as a measure of liquidity.

48. Actual contract prices reported by exchanges and financial reporting services are not based on contracts with open interest. Therefore, the volumetric data provides a better indication

[14] Brattle EAS Affidavit, ¶ 46.

of whether reported prices reflect a liquidly-traded delivery point for a liquidly-traded delivery month.

49. For purposes of determining whether prices reflect actual trades and futures contracts are liquidly-traded for purposes of the E&AS Offset methodology, open interest is the wrong measure. Instead, volumes should be used to ensure that a hub is liquidly traded during the thirty trading days prescribed by the forward-looking methodology for delivery during the RPM delivery period.

III.1.3 Volumes indicate lack of liquidity for natural gas delivery hubs

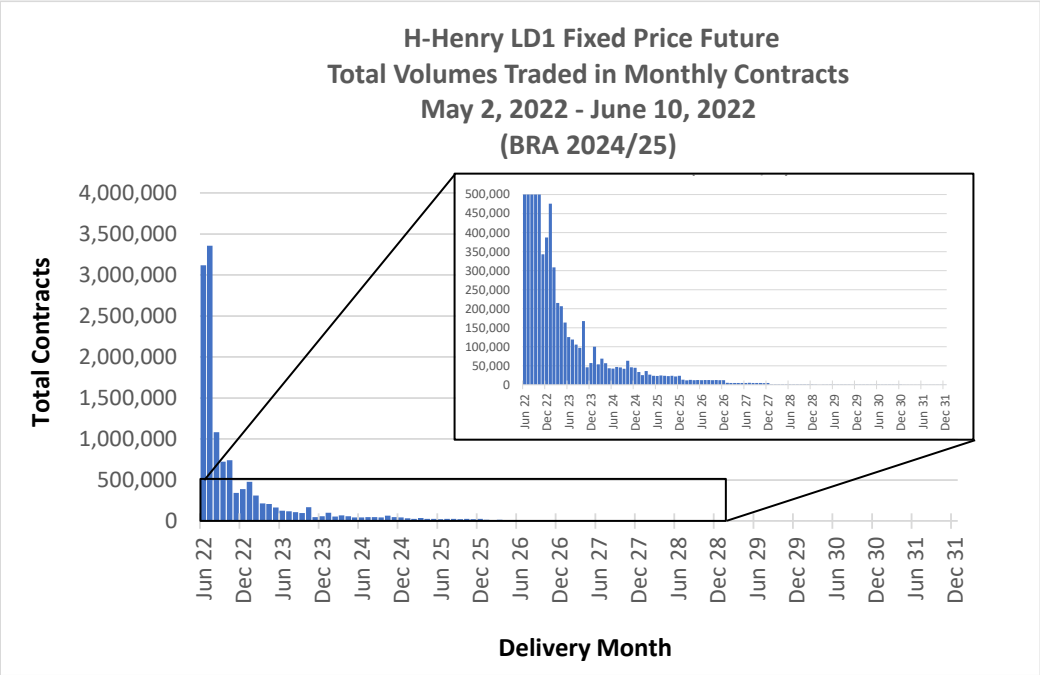
50. To understand how many trades would underly prices used in a forward-looking approach, I submitted for, was approved, and purchased ICE data and performed a liquidity analysis of the proposed electricity and natural gas trading hubs for the trade days that would be designated if the forward-looking approach were applied to the 2024/25 delivery period. As an illustration, the following analyses uses the thirty trading days prior to the BRA scheduled in December 2022 for the 2024/25 delivery period.

51. The basis for measuring liquidity is Henry Hub, a robustly-traded natural gas hub in the U.S.. Henry Hub is a natural gas pipeline located in Erath, Louisiana that serves as the delivery point for futures contracts traded on the New York Mercantile Exchange (NYMEX). The hub location and owner has access to many major gas markets in the U.S., including four intrastate pipelines, and nine interstate pipelines interconnecting across much of the U.S.. Henry Hub contracts have been trading for more than thirty years.

52. Henry Hub serves as the benchmark for North American gas markets, against which a basis (i.e., difference between delivered hub and Henry Hub) may be traded. If Henry Hub is not liquidly traded for a given contract month, the basis is unlikely to be liquidly traded. In general, natural gas delivery hubs within PJM would have less liquidity than Henry Hub.

53. **Figure 4** illustrates the total number of trades for a 30-day trading period 180 days prior to the scheduled BRA for 2024/25 delivery.

Figure 4: Trade Volumes of Henry Hub Futures for the 2024/25 Delivery Period



Source: Analysis of ICE Data

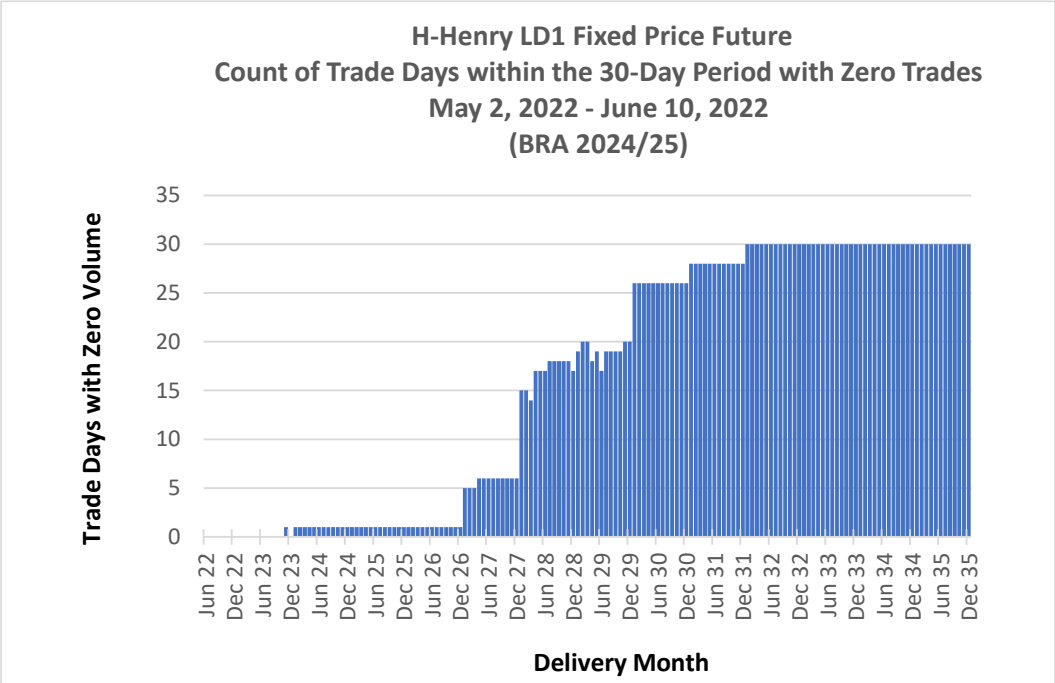
54. Contracts are very liquidly traded a few months out, and then the number of contracts traded during the 30-day period prescribed in the forward-looking E&AS Offset methodology drops precipitously. By the actual delivery period of June 2024 to May 2025, very few contracts were traded during the 30-day period. Even fewer contracts are traded three years out, past June 2025, as would be required if the forward-looking E&AS Offset approach is adopted for future RPM auctions.

55. Another way to measure liquidity is to determine whether monthly contracts are traded on a daily basis.

56. For purposes of assessing liquidity underlying the E&AS estimation prices, the 30-day trading period prescribed by the E&AS Offset methodology is key. Those trade days are the basis for the proposed prices used in the dispatch model to calculate net revenues for the reference unit. If there are not regular daily trades for future delivery during those trade dates, settlement prices would not necessarily reflect market expectations for the future delivery period.

57. **Figure 5** counts the trade days within the 30-day prescribed period to determine how many of the trade days have zero trades for a given delivery month.

Figure 5: Henry Hub Trade Days in the 30-day Period with No Trades by Delivery Month



58. Given that other natural gas delivery locations tend to be traded as a derivative of Henry Hub, this chart illustrates the maximum expected liquidity for the specified natural gas trading hubs within PJM. Henry Hub is traded on almost a daily basis two years out before there are some missing trade days. By five years out, liquidity as measured by trading volumes tends to decline, with more than half the days in the 30-day period having no trades six years or further out from the trade date.

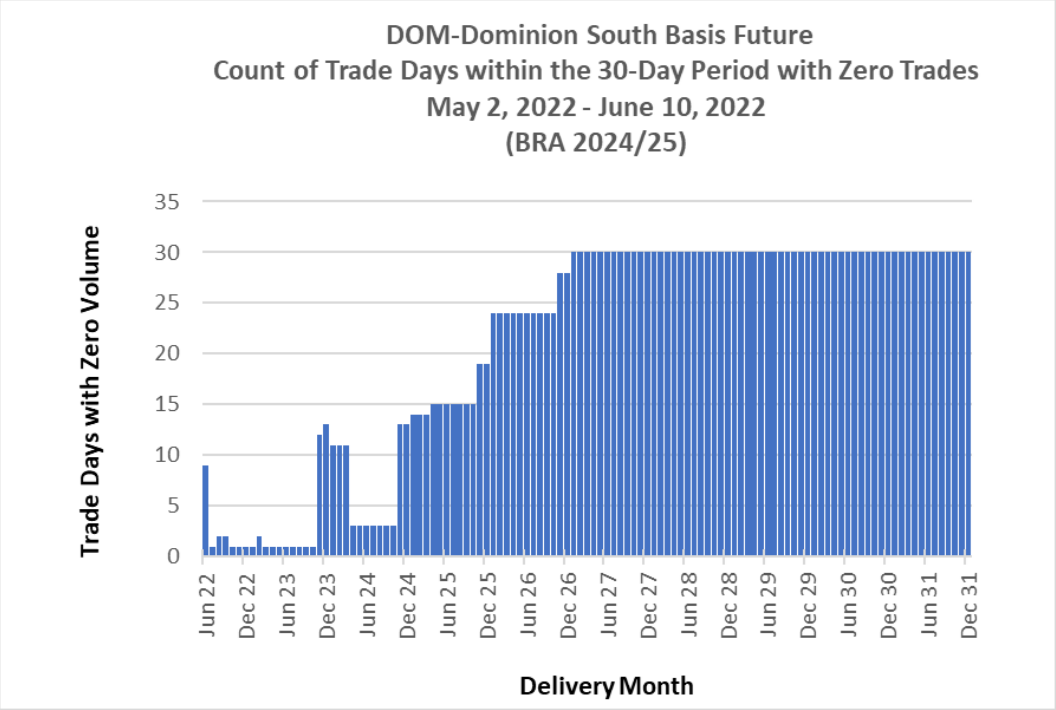
59. A similar pattern, but with daily trades disrupting earlier, occurs for Dominion South, one of the PJM natural gas hubs identified for use in the forward-looking E&AS Offset methodology. Of the PJM natural gas price hubs identified for use in the forward-looking methodology, Dominion South trades the highest volume of basis contracts.

60. Basis reflects the price differential between the delivery hub and Henry Hub, and can be used as a hedge to offset risk of transportation costs to the PJM delivery point. When delivered prices are higher than Henry Hub, the basis is positive. When delivered prices are lower, the basis is negative. Basis trades may be combined with the Henry Hub futures price to obtain a fixed price for delivered natural gas at the PJM delivery point.

61. In the case of Dominion South, there are a number of days in the 30-days of trade data where no trades occur. Generally, monthly contracts are traded on close to a daily basis two years out from the trade dates. After two years, one-third of the 30 prescribed trade dates do not have any traded contracts. After three years from the trade date, half of the trade days in the 30-day trading period that set the price do not have any contracts traded

for that future delivery month. By the fifth year after the E&AS offset trade dates, there are no trades recorded (**Figure 6**).

Figure 6: Dominion South Trade Days in the 30-day Period with No Trades



62. Based on traded volumes, Dominion South may be useful for near-term delivery periods going out one year. However, by three to four years out, representing the delivery period for RPM obligations, there is a clear lack of liquidity in futures trades as measured by daily trading.

III.1.4 Volumes indicate lack of liquidity for PJM energy delivery hubs

63. Electric energy price futures for PJM hubs are even less liquidly traded.

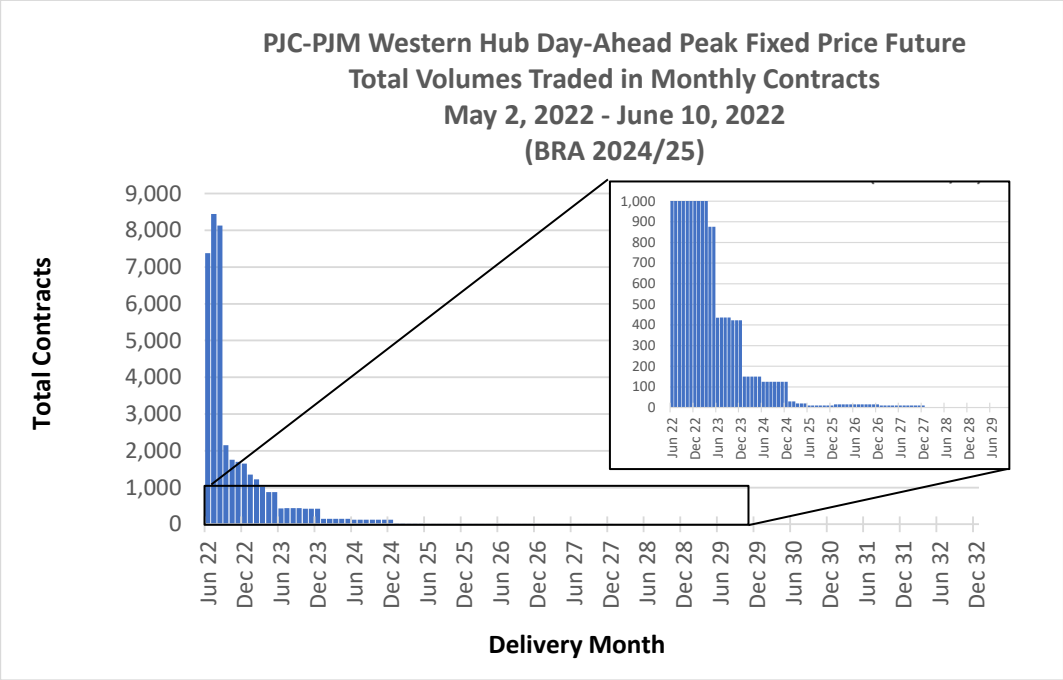
64. The PJM Western Hub Fixed Peak Monthly Futures, the most robust trading point in PJM markets, barely trades past 18 months (**Figure 7**). By the time the RPM delivery period begins three years and a half years later, the number of trades in the trading period used to set the energy price for E&AS would drop to less than two dozen transactions.

65. Given that each of the PJM Western Hub Day-Ahead Peak contracts represents 1 MW, there would be less than 25 MW of trading setting the RPM price – either directly or

through an adjustment for illiquidly-traded hubs -- for up to 145,000 MW of capacity across the entire RTO.[15]

66. In addition, most of those transaction would be either block trades tied to a larger obligation or small offer trades exercised by traders to test the market. They do not represent a robust market or a robust market price.

Figure 7: Volumetric Liquidity of PJM Western Hub Peak Fixed Price Futures



Source: Analysis of ICE data

67. **Figure 8** counts the trade days within the 30-day prescribed period to determine how many of the trade days have zero trades. This provides an indication of whether the volume of trades for a given delivery month are traded on a daily basis or sporadically.

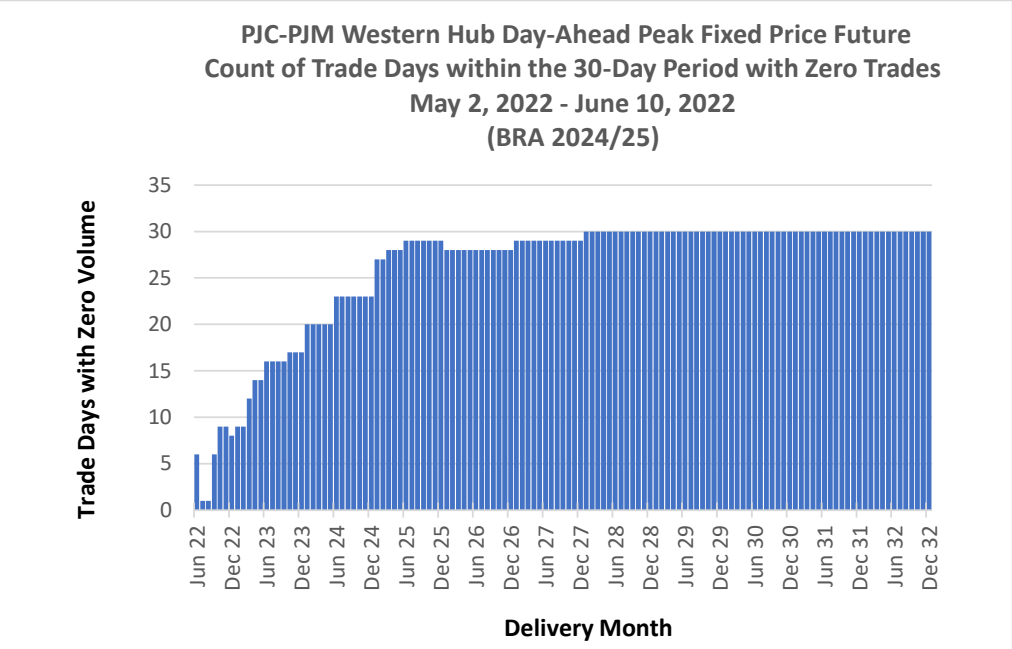
68. By three years out, more than 25 days have zero trading volume. In other words, contracts for a given delivery month are only transacted in less than five of the prescribed 30 trade dates.

69. The PJM filing claims "the PJM Western Hub remains one of the most liquid trading hubs in the nation."[16] Therefore, any conclusions regarding lack of liquidity for the PJM Western

[15] PJM, 2023/24 Base Residual Auction Results, https://sdc.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx
[16] PJM Filing Cover Letter, p. 36.

Hub apply to other PJM hubs. With such a small number of contracts available to set prices more than three years out, and lack of daily trades during the prescribed 30-day period, use of the futures price methodology is a spurious approach to estimating the E&AS Offset.

Figure 8: PJM Western Hub Trade Days in the 30-day Period with No Trades



70. The forward-looking approach proposed by PJM may have been less problematic when PJM first introduced the methodology to the Commission and the Commission approved it as being just and reasonable. Due to various implementation delays in the PJM RPM markets, the temporal distance between the BRA and delivery period tightened to be around two years or less for the 2022/23 through 2024/25 RPM delivery periods.

71. Although this tighter period arguably could have sufficient liquidity to support the use of futures when PJM proposed the forward-looking approach to the Commission, the forward-looking approach fails under the current proposal today when expectations are that the RPM delivery period will be more than three years away from the relevant trade dates.

72. Per PJM, the proposed BRA date for the auction tied to the 2026/27 delivery period is scheduled to occur November 2023.[17] The prescribed futures trade dates to estimate PJM energy prices for dispatch would be in spring 2023. Those trade days are not yet available to test liquidity. However, taking futures pricing data six months in advance, would place the trade data required for the E&AS Offset three to four years earlier than the RPM

[17] PJM, https://insidelines.pjm.com/pjm-compliance-filing-proposes-new-capacity-auction-timelines/

delivery period. Based on current trading conditions, there is not likely to be enough trades to set a robust market price.

73. There simply is not enough liquidity in PJM energy hubs three years out from trading dates to use futures as prescribed in the proposed E&AS Offset methodology.

74. It would be unjust and unreasonable to rely on energy prices based on illiquid futures contracts for 2026/27 and beyond given the three-year delivery lead time.

III.1.5 Settlement prices are based on proprietary algorithms

75. The forward-looking E&AS Offset methodology uses the settlement price for setting the electricity and natural gas prices used in the dispatch model. Settlement prices can be calculated in a number of ways, and generally is set by defined procedures that vary according to the exchange and asset traded.

76. ICE defines its settlement price for its U.S. futures exchanges as follows:

> The term "Settlement Price" shall mean the daily price of a Commodity Contract as determined by the Exchange on any day for the purpose of meeting Margin requirements on such day.[18]

77. The settlement price, therefore, is not an average price of traded contracts. It is not the opening price or the closing price. The settlement price used as the basis for the forward-looking E&AS Offset methodology is simply a price that ICE generates for purposes of margin calls.

78. Margin calls are not agreed-upon prices between parties, but a means of collecting collateral when a contract is out-of-the money (i.e., the settlement price is below the forward price that will be collected upon delivery).

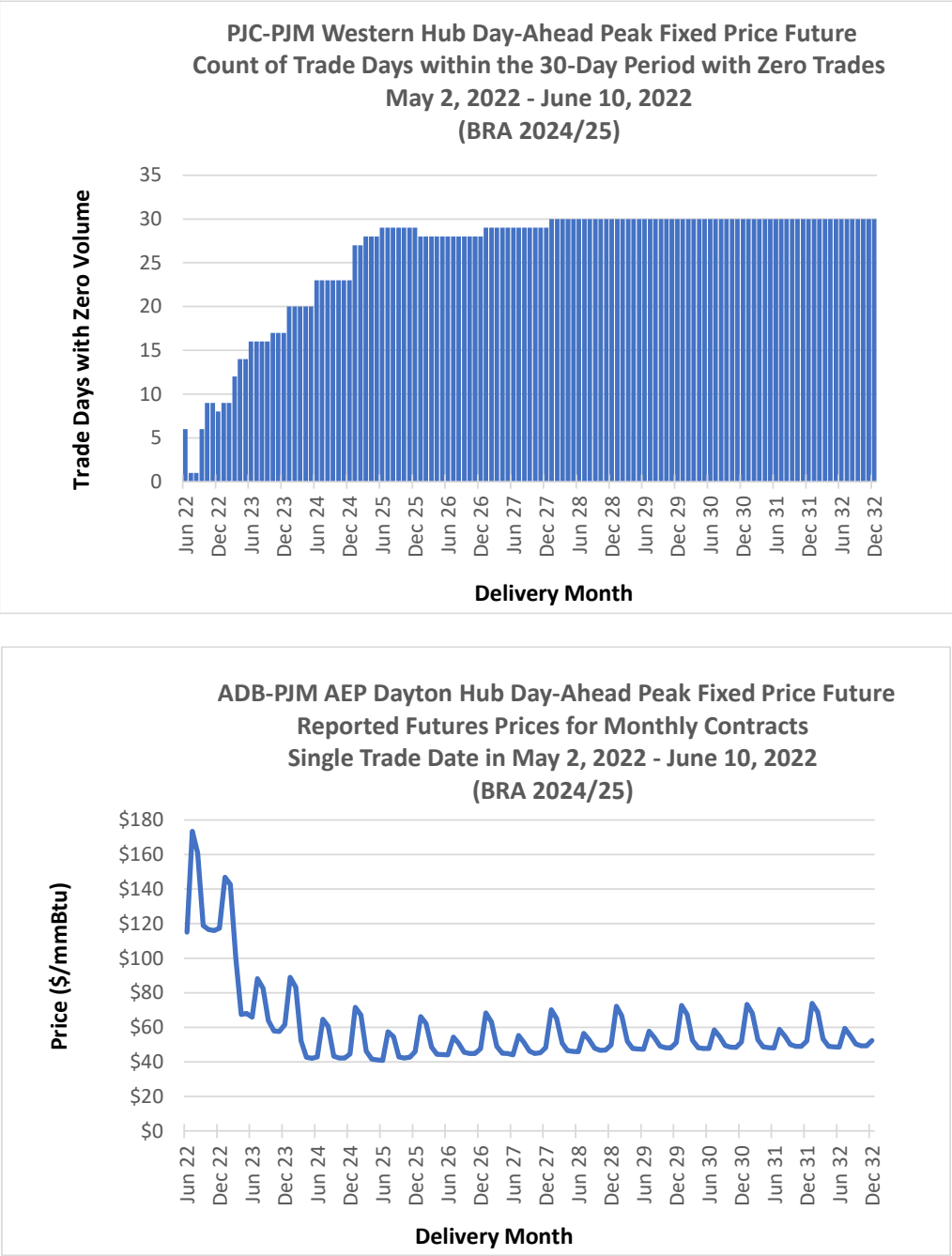
79. Settlement prices are reported daily, even when there are no trades to support the price.

80. Proprietary trade data providers such as Bloomberg and ICE have developed their own algorithms to generate settlement prices. These algorithms project a representation of prices for futures contracts that extend well beyond the liquidly-traded period.

81. **Figure 9** illustrates this point for AEP Dayton, another PJM electric energy delivery hub recommended to be used for calculating the forward-looking E&AS Offset.

[18] ICE, ICE Futures U.S.®, Inc. Definitions, p. 1-15, https://www.ice.com/publicdocs/rulebooks/futures_us/1_Definitions.pdf

Figure 9: Trade Days in the 30-day Period with No Trades versus Reported Settlement Prices



Source: Analysis of ICE data

82. A side-by-side comparison indicates that, despite zero trade volume during the prescribed 30-day trading period in the out-years past 2027, ICE still reports settlement prices for those monthly futures contracts.

83. The pricing chart also represents a single trade day that had no trades for any of the monthly contracts. ICE price data includes settlement prices for monthly contracts with zero trades during the 30-day period regardless of the delivery month.

84. ICE settlement prices for contracts with zero trades do not represent market transactions for that monthly contract on that day. Recognizing that clients use the pricing data in different ways, ICE has developed proprietary algorithms to generate settlement prices generated from proprietary algorithms to complete the price series, even if there are zero trades during that trade day.

85. Both Bloomberg and ICE have algorithms that serve to populate price data extending into futures months where there are no volumes traded. Lack of trading on a given trade day do not necessarily preclude proprietary databases from posting an estimated price for that trade day. In fact, those exchanges post the settlement price specifically for purposes of collecting collateral.

86. Brattle claims that those prices are used by traders with open interest to exchange value and "mark-to-market."[19] This rationale does not make use of futures data during illiquidly-traded periods appropriate for calculating the Net CONE.

87. Mark-to-market accounting is used to post collateral for trades between parties prior to final settlement at the delivery date. That settlement can occur on a daily basis. Algorithmic prices used for mark-to-market accounting are not representative of a price that two parties agree to for purposes of a one-time trade. Instead, they are used as interim tracking of the relative position of each party until actual settlement occurs on the contract settlement day.

88. Given the lack of trades for delivery more than three years into the future, Brattle effectively is arguing that the Commission adopt the ICE algorithm for the settlement price as the basis for estimating the E&AS Offset. Unlike to purported use of settlement prices which are used for mark-to-market and collateral calls adjusted daily, however, the forward-looking E&AS methodology would take a one-time snapshot of those settlement prices and apply them to the entire delivery year three years and beyond into the future. There would be no true-up or "settlement" when settlement prices change. This is why use of settlement prices for illiquid markets such as the PJM hubs and energy delivery points are problematic for use in the RPM.

89. Therefore, the proposed forward-looking approach to estimate E&AS fails the liquidity requirement and is inappropriate for use in developing an E&AS estimate for the proposed RPM delivery periods starting in 2026/27.

90. The charts presented in this section also show that if trade data provided by ICE were to be used three to four years in advance of the delivery period to set the E&AS Offset, those futures prices would be price projections almost solely based on the ICE proprietary algorithm without the benefit of any actual trades on those trade dates.

[19] Brattle EAS Affidavit, ¶ 45.

91. Among the many other problems tied to adopting the ICE algorithm, including lack of transparency and uncertainty, that algorithm is proprietary and could change without notice, thereby impacting Net CONE and RPM market clearing prices.

92. I have no basis for an opinion as to whether the ICE algorithm in and of itself can result in just and reasonable rates for purposes of PJM's RPM markets. The algorithms that generate estimated futures prices are proprietary, highly confidential, and not shared with the public. They also can change without notice.

93. Given the lack of transparency regarding how those prices are calculated, and knowing that they generally will not be based on actual transactions for the BRA delivery period, I do recommend against relying on a proprietary algorithm for setting a PJM market price.

III.1.6 An adjustment for lack of liquidity compounds the problem

94. The forward-looking E&AS Offset proposed by PJM includes flexibility to use trading hubs based on liquidity, and an adjustment in cases where futures price data is not liquidly traded.

95. This proposal does not define what constitutes an "illiquid" market.[20]

96. The adjustment does not provide a solution – it simply adds another algorithmic calculation onto settlement prices that already are estimated using a proprietary algorithm for incorporation into another proprietary algorithm on which the market model depends.

97. The forward-looking E&AS Offset methodology is simply inapplicable to an RPM auction three years in advance of the delivery period.

[20] PJM's filing appears to be advocating for the proposed forward-looking methodology as a means of increasing liquidity in futures markets for energy:

> For example, although the PJM Western Hub remains one of the most liquid trading hubs in the nation, activity at other trading hubs is evolving, and if anything, could be spurred by the implementation in use, over time, of this forward-looking EAS Offset.

Financial markets hedge physical markets. Physical energy markets already exist in PJM and financial markets have developed around them. A desire to have more liquidly-traded energy markets is not a reason to incorporate financial settlement price data for energy markets into a physical capacity market design (PJM Filing Cover Letter, p. 36).

III.2 Input data required for the forward-looking approach is not publicly-available

98. Whereas the current approach to estimating the E&AS Offset relies on historical pricing data that was publicly-available on PJM's website, futures data required to calculate the forward-looking E&AS Offset is proprietary trade data that is not publicly-available.

99. According to 17 CFR 160.3 [Title 17 -- Commodity and Securities Exchanges; Chapter I -- Commodity Futures Trading Commission; Part 160 -- Privacy of Consumer Financial Information], publicly available information means:

> . . . any information that you reasonably believe is lawfully made available to the general public from:
>
> (i) Federal, state or local government records;
> (ii) Widely distributed media; or
> (iii) Disclosures to the general public that are required to be made by federal, state or local law.[21]

100. Brattle uses ICE data available through Bloomberg.

a. Bloomberg is a proprietary financial data source that is a subscription service. Bloomberg compiles publicly-available and others proprietary financial data and makes that available to subscribers on Bloomberg-specific terms. The Bloomberg contract prohibits licensed users from sharing data with other individuals within the firm or third-parties who are not explicitly covered by the license.

b. ICE is a trading platform and provides a centralized market for many of the financial contracts relevant to PJM energy hubs and natural gas delivery points used by PJM generators. ICE also runs a subscription service for its data, but must pre-approve recipients and generally allows only active market participants and traders to receive its pricing data on a real-time basis. Non-subscribers may be able to obtain historical trade data at a price. The data license prohibits licensed users from sharing data with third-parties unless specifically listed in the license.

c. Other proprietary energy databases generally do not carry ICE trading data. Instead, they provide access to public sources such as NYMEX, NASDAQ and CME quotes and other trade data. In 2020, PJM energy hubs traded on these other trading platforms were delisted due to lack of liquidity on those platforms. For now, ICE data would be the only accessible comprehensive source of futures pricing data going forward, and only to the extent there is sufficient liquidity.

[21] Legal Information Institute, https://www.law.cornell.edu/cfr/text/17/160.3

In summary, the futures trading data that underlies the forward-looking E&AS Offset is not publicly-available, requires a purchase of the proprietary data, and such data generally may not be made public or be provided to third parties.

101. ICE does post a limited number of recently traded days on its website, but the data is still proprietary and the user must agree to the following:

> In order to receive the proprietary data from this website, you acknowledge and agree that you shall not disclose, transmit, distribute or disseminate, either directly or indirectly through any third parties, the market data and information contained herein to any person or entity without the express written consent of ICE Data Services. The market data and information contained herein constitutes confidential information and valuable property owned by ICE Data Services, its affiliates, licensors and/or other relevant third parties. Furthermore, you acknowledge that you have read and agree to all terms presented in the following document: ICE Report Center Terms and Conditions.[22]

102. The input data required for the forward-looking approach may be accessible, but it is not publicly-available. Contracted access to the data limits wider distribution. As mentioned above, the settlement price data is generated by proprietary algorithms for which the underlying calculations are confidential.

103. Reliance on proprietary data for the inputs required to calculate E&AS under the forward-looking renders the proposed methodology non-transparent and unable to be replicated.

III.3 The forward-looking approach relies on proprietary software

104. Whereas the historical approach to estimating the E&AS Offset can be calculated using a widely-available spreadsheet or database software, for which the calculations are able to be reviewed and audited, PJM relies on a proprietary market modeling software to perform the forward-looking approach for calculating the E&AS Offset.

105. The PLEXOS license must be purchased, and training is required to understand how to operate the model.

106. PLEXOS is not publicly-available according to the definition in 17 CFR 160.3.

107. The PLEXOS dispatch optimization model includes proprietary algorithms and inputs that are not publicly available and generally are not disclosed in the operator manuals available to subscribers.

[22] ICE, https://www.theice.com/marketdata/reports

108. The use of PLEXOS and its proprietary algorithms to estimate the E&AS Offset makes the proposed forward-looking methodology non-transparent and difficult to confirm.

III.4 PJM does not provide sufficient backup data to replicate the results

109. In support of its proposed Net CONE values and E&AS Offset estimates, PJM provided a simple spreadsheet of the outputs.

110. Based on the litigations and regulatory proceedings in which I have been involved, where market models such as PLEXOS are used, full transparency and replicability requires provision of source data, input data calculations such as a pre-processing spreadsheet, input data and other model triggers/assumptions used in the model runs, raw model results, post-processing spreadsheets, and final results.

111. By providing only a hard-coded spreadsheet of the outputs, PJM fails to meet the standard requirements for full transparency and replicability.

a. Nearly all entries in the spreadsheet provided were hard-coded, preventing a clear understanding of the basis for the values used in PJM's calculations.

b. PJM did not provide proprietary input data pulled from Bloomberg, and provision of such data to undisclosed third parties is restricted under the Bloomberg license.

c. PJM did not provide proprietary input data using ICE futures price data, and provision of such data to undisclosed third parties restricted under the ICE data license.

d. PJM did not provide any algorithms used by ICE or Bloomberg to calculate settlement prices; they most likely do not have access to those proprietary algorithms.

e. PJM did not indicate whether the futures prices from the Bloomberg ICE trade data was based on actual trades or a proprietary algorithm.

f. PJM and Brattle did not provide an analysis of liquidity for the proposed data sources three to four years out from the trade dates, instead relying on an open interest analysis.

g. PJM did not provide access to the proprietary PLEXOS model; the license precludes public access.

h. PJM did not provide the pricing inputs that Brattle ran through the PLEXOS model to calculate the E&AS Offset in support of the proposed approach; provision would likely be a violation of both the Bloomberg and ICE licenses.

i. During the course of litigation and regulatory proceedings, where proprietary data is used, and required to be made available through a discovery process, recipients may be required to sign a non-disclosure agreement in order to receive the proprietary data and model results. As far as I am aware, PJM did not offer this option to interested parties.

As a result, PJM failed to provide adequate information to ensure transparency and to allow others to replicate Brattle's projected E&AS Offset results using the forward-looking methodology.

112. The proprietary nature of the trade data source, proprietary nature of the trade data compilation, algorithms underlying prices for trade dates that are not liquidly-traded, and algorithms embedded in the PLEXOS model most likely precluded PJM from making the data available to third parties.

113. Going forward, it is unclear whether PJM intends to provide the relevant data and procedures tied to its use of Bloomberg, ICE and PLEXOS proprietary data and processes.

114. If the forward-looking E&AS Offset is approved, despite the critical flaws identified above, the obligation to provide transparency in organized markets requires the details underlying the inputs, calculations, assumptions, and outputs of the E&AS Offset to be made available to the public and that such obligations clearly delineated in the tariff.

IV. THE COMBINED CYCLE CREATES PERVERSE RPM PRICE INCENTIVES

115. Choice of an appropriate reference unit technology may vary by region, market conditions and capacity market design. Choosing the appropriate technology, whether a combined cycle or any other technology such as renewables and/or energy storage, is the point of PJM's quadrennial review. As technologies for new entry become more efficient or are impacted by state policies, the designated reference unit may have to change.

116. Adopting the combined cycle as the reference unit in this case, however, is inappropriate and magnifies perverse price incentives for the RPM market. These perverse price impacts are heightened by the increased RPM price volatility that PJM's other proposed changes create.

117. These perverse price incentives, magnified by use of the combined cycle in conjunction with PJM's other changes, also could have an adverse impact on reliability if not corrected or back-stopped by PJM with one-off contracts that can create regulatory and market uncertainty.

118. Given the structure of PJM's VRR Curve, and current energy market volatility, adopting a reference unit that has a significant level of energy revenues in the E&AS Offset creates a capacity market that is built around parameters that have an inverse relationship with short-

term conditions in energy markets. This converts the RPM from a market for capacity procurement through stable price signals to a physical hedge for energy producers.

119. The net result of the switch to a combined cycle, in conjunction with the other proposed changes, is to lower RPM prices when capacity is needed most.

120. PJM's markets continue to be dependent on the price of natural gas. If natural gas prices are high, energy prices tend to be high; if lower, energy prices tend to be lower. The relationship is tied to the heat rate of the marginal gas-fired generating unit that sets the price for energy. The difference between energy price received by a generator for electricity produced and the natural gas price required to produce that electricity is referred to as the spark spread.

121. When energy markets have excess generation capability, average spark spreads tend to be lower and market price volatility declines. Net revenues generated by energy and ancillary services net revenues would be lower due to the tighter margins, sending a signal to exit the market.

122. When energy markets have tight supply conditions, average spark spread tends to be higher and energy market price volatility increases. Net revenues generated by energy and ancillary services would increase due to the higher margins, sending a signal for new entry.

123. The reference unit represents a new entrant that generally would operate more often than a higher heat rate combustion turbine, generating higher energy and ancillary services revenues during tight supply conditions.

124. In energy-only markets, higher energy prices send the price signal to build new capacity. In PJM, which has a separate market for capacity, the price signal for new entry and exit of reliability resources is designed to come from the RPM.

125. Following economic theory, prices should rise to encourage new entry when additional reliability resources are needed and fall to encourage exit when excess capacity is keeping net revenues below the long-run marginal cost of production. The RPM design relies on a defined reference unit to represent the long-run marginal cost of production for purposes of structuring the demand curve that, combined with supply offers obtained through the BRA, set the market clearing price and quantity of reliability resources.

126. RPM is designed to procure capacity in a market separate from the energy market. A combustion turbine consistently has been the reference unit that serves to set the parameters around a long-run marginal cost for capacity required to encourage new entry. Based on the recommendation from Brattle, PJM now proposes to change the reference unit to a combined cycle unit.

IV.1 Using a combined cycle magnifies perverse price incentives

127. A combined cycle reference unit magnifies the potential for perverse price incentives embedded in the VRR Curve and RPM design.

128. The greater level of energy net revenues for a combined cycle means that the E&AS offset plays a much larger role in determining Net CONE. As a result, the relative volatility of Net CONE estimates for the combined cycle is greater than that of the combustion turbine.

129. Under Brattle's analysis of Net CONE, the combustion turbine reference unit was projected to generate energy only 25 percent of the time.[23] The proposed combined cycle reference unit is projected to operate 75 to 85 percent of the time.[24]

130. The problem posed by adopting the combined cycle as the reference unit is the significant amount of energy that the technology is projected to produce through dispatch in short-term energy markets. The much higher capacity factor of a combined cycle generates higher net revenues which increase the E&AS Offset and decreases Net CONE.

131. Moving away from the combustion unit in PJM to a combined cycle that is projected to produce a significant amount of energy and associated net revenues, pollutes the shape of the VRR Curve such that RPM cannot produce a proper directional price signal to encourage new entry or discourage continued operations of excess capacity.

132. The reason that a combined cycle reference unit creates perverse price signals is because of the RPM's reliance on the Net CONE of the reference unit and the role of Net CONE in defining the parameters of the VRR Curve for each BRA.

133. The Net CONE, as calculated in the RPM design process, is inversely related to net revenues from sales into the energy and ancillary services market. The higher the E&AS Offset, the lower Net CONE.

134. A lower Net CONE shifts the "kink" in the demand curve down the same point on the reliability x-axis, making the slope of the supply curve above the inflection point steeper and the slope below the Net CONE flatter (**Figure 10**).

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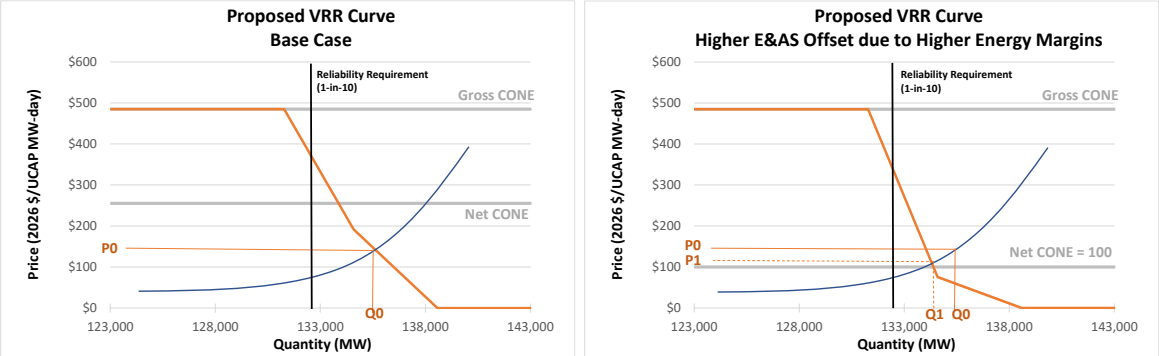
[23] Calculated using the 2022/23 MOPR estimates, Zonal Average Supporting Data, Preliminary Forward-Looking E&AS Revenue Offset (1/13/2021), https://www.pjm.com/markets-and-operations/rpm.aspx (Under the 2022/23 dropdown menu, zip file with the excel file: "Supporting Files for New Forward-Looking Net EAS Offset Methodology".

[24] Ibid., The Brattle estimate for 2026/27 used to calculate capacity factors is provided in the PJM Informational Posting, https://pjm.com/-/media/committees-groups/committees/mic/2022/20220718-special/quad-review_2026-27-projected-eas-dispatch-zonal-average-details.ashx

Figure 10: Illustration of Impact of Higher Spark Spreads on RPM Market Prices

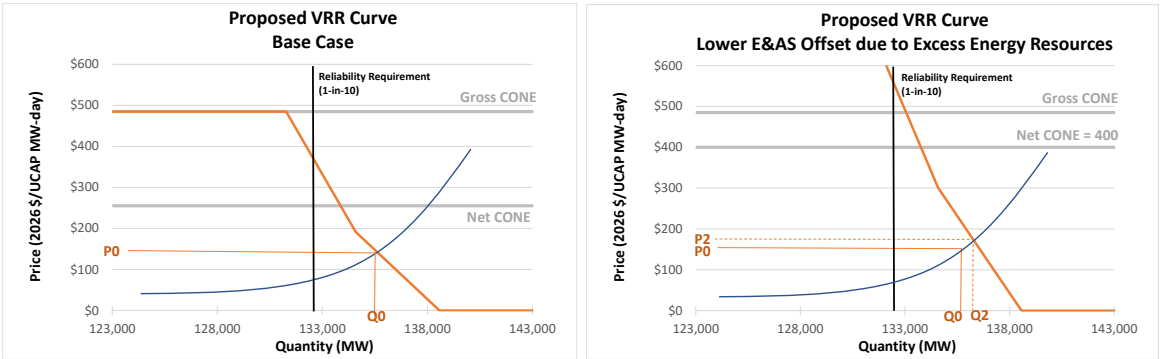


135. When E&AS Offset is higher due to higher energy market margins, the RPM demand curve shifts to the left. Quantity decreases from Q0 to Q1, and prices decrease from P0 to P1.

136. When higher energy market margins indicate tighter capacity conditions, which should send a *higher* price signal to new entrants, the RPM actually generates a *lower* price signal.

137. In contrast, when energy margins tighten (e.g., due to excess capacity supply), the E&AS Offset decreases, Net CONE increases, the VRR Curve shifts to the right, and RPM market clearing prices increase from P0 to P2. The RPM would then procure more capacity, increasing from Q0 to Q2 (**Figure 11**).

Figure 11: Illustration of Impact of a Lower Spark Spreads on RPM Market Prices



138. The Net CONE of a pure capacity unit that earns no E&AS revenues would not change with energy market conditions, and Net CONE only would decrease or increase as the costs of new entry changed due to technological improvements or greater efficiency. The current reference unit, a combustion turbine, generally operates only during a subset of peak hours. In contrast, a combined cycle's higher level of dispatch and greater sensitivity to energy prices magnifies the impact of energy markets on RPM market clearing prices.

139. The perverse price signal is not as problematic under the current Net CONE methodology where: (i) the reference unit is a combustion turbine, (ii) the E&AS Offset is estimated using a more stable three-year average of historical prices and only for on-peak hours, and (iii) the angle of the VRR Curve under the "kink" is more horizontal. All three of those market design components mitigate the price impact of short-term energy markets on the price signal for long-term capacity meant to be procured through the VRR Curve.

140. By relying on the combustion turbine as the capacity unit, which operates much less often in energy markets, the majority of VRR Curve adjustments occur due to changes in capital costs due to changing efficiencies and capital costs of production, consistent with a long-run marginal cost of production.

141. Changing to a combined cycle introduces a greater influence of energy markets into the RPM, magnifying the E&AS Offset issues by generating a perverse price signal and creating a counter-intuitive set of incentives when energy markets are signaling a need for new capacity.

142. The next subsection describes how changes to the combined cycle also increases volatility around the perverse price signal, further challenging the role of the RPM. **Section V** describes how the steeper VRR Curve serves to increase the magnitude of the perverse price signal even further and **Section VI** addresses the increased impact of price volatility through the forward-looking E&AS Offset proposal.

IV.2 Adopting a combined cycle increases volatility in Net CONE estimates

143. Given the perverse price signals that incorporation of energy market spark spreads into the RPM creates, it is better to mitigate the movement around estimated Net CONE so as to create a more stable VRR Curve and mitigate the impact of the wrong price signal.

144. The analyses described in this affidavit consistently show that the combustion turbine, with and without the current RPM rules regarding the E&AS Offset, generate a more stable set of Net CONE estimates regardless of the underlying market conditions.

145. In effect, a combined cycle reference unit will increase volatility in the Net CONE, VRR Curve, and RPM prices. This serves to magnify the perverse RPM market price incentives described above.

146. Brattle estimates of Net CONE for a combustion turbine and combined cycle for the 2022/23 MOPR and 2026/27 Brattle Estimate indicate that the Net CONE of a combustion turbine is less volatile.

147. **Figure 12** illustrates a statistical analysis of Brattles estimates for 21 different PJM zones using the proposed forward-looking EAS estimate. Correcting the table to calculate Net CONE as the Gross CONE less E&AS Offset, and calculating the mean and standard deviation for each zone, shows that the Net CONE for a combined cycle tends to be more

volatile on an absolute and relative basis compared to the combustion turbine, whether based on the 2022/23 MOPR or Brattle Estimate.[25]

Figure 12: Net CONE Statistics by Technology and BRA Based on Brattle Estimates

	CC 2022/23 MOPR	CC 2026/27 Brattle Estimate	CT 2022/23 BRA	CT 2026/27 Brattle Estimate
	Net CONE	Net CONE	Net CONE	Net CONE
All Zones				
Count	**21**	**21**	**21**	**21**
Average	**$ 112**	**$ 274**	**$ 237**	**$ 325**
Standard Deviation	**$ 44**	**$ 51**	**$ 25**	**$ 34**
Coefficient of Variation	**0.39**	**0.19**	**0.10**	**0.11**
Cone Area 1 - EMAAC				
Count	6	6	6	6
Average	$ 159	$ 329	$ 259	$ 341
Standard Deviation	$ 18	$ 25	$ 12	$ 15
Coefficient of Variation	0.11	0.08	0.05	0.05
Cone Area 2 - SWMAAC				
Count	2	2	2	2
Average	$ 123	$ 257	$ 243	$ 319
Standard Deviation	$ 45	$ 42	$ 24	$ 33
Coefficient of Variation	0.36	0.17	0.10	0.10
Cone Area 3 - RTO				
Count	10	10	10	10
Average	$ 88	$ 252	$ 228	$ 324
Standard Deviation	$ 27	$ 35	$ 14	$ 28
Coefficient of Variation	0.30	0.14	0.06	0.09
Cone Area 4 - MAAC				
Count	3	3	3	3
Average	$ 90	$ 250	$ 218	$ 299
Standard Deviation	$ 64	$ 77	$ 45	$ 72
Coefficient of Variation	0.71	0.31	0.21	0.24

148. The stability that combustion turbines provide to the RPM Net CONE calculation, and therefore the RPM price, can be seen in three ways:

a. **The CT is more stable across quadrennial review assumptions:** The first four rows indicate the cross-sectional variability across 21 different PJM zones.

i. For the combined cycle, the average Net CONE is $112 / MW-day in the 2022-23 MOPR analysis versus $274 / MW-day in the 2026/27 Brattle Estimate, a swing of $262 / MW-day.

ii. In contrast, the combustion turbine estimate increases from $237 / MW-day to $325 / MW-day, a swing of $188.

iii. The coefficient of variation does not change by much for the combustion turbine, indicating relatively consistent variability. This shows the

[25] Brattle CONE Affidavit, Tables 20, 28, pages 55, 68. Note that the last column has a calculational error and has been corrected for purposes of this analysis by simply subtracting the E&AS Offset from the Gross CONE.

stability of the Net CONE across quadrennial review assumption changes.

b. **The combustion turbine is more stable across PJM zones:** Although market conditions vary across all of the PJM zones, the combustion turbine has less volatility as measured by the standard deviation and coefficient of variation compared to the combined cycle per the 2026/27 Brattle Estimate.

c. **The combustion turbine consistently has less volatility within each zone:** The statistics for cross-sectional analyses within each zone indicates that the combustion turbine consistently has a lower volatility and coefficient of variation.

According to the cross-sectional analysis, a combustion turbine has a tighter range for potential Net CONE, on average, when compared to the combined cycle, providing greater consistency across the PJM regions.

IV.3 A combined cycle is inconsistent with the goals of RPM markets

149. Unlike energy markets where volatility creates greater optionality, RPM markets benefit from stability. RPM markets procure capacity from reliability resources, and are meant to compensate for the capital costs required to provide that capacity. Using a combustion turbine as the reference unit is consistent with these goals.

150. Once built, capacity has little optionality – it is either available or unavailable. Mothballing a generator to preserve the option for future use can be an expensive undertaking, but effectively takes the generator out of commission so that it is not available to provide capacity as needed.

151. Adding volatility from energy markets into capacity markets creates perverse incentives for new investment that is looking for a stable price signal.

152. PJM's proposal to move to a combined cycle reference unit from a combustion turbine therefore creates two perverse incentives:

a. Market clearing price levels will be lower when capacity is needed most (and higher when capacity should exit); and

b. Volatility around RPM market prices from year-to-year is higher with a combined cycle, decreasing stability for new entrants that do not depend on energy markets for most of their revenues, challenging access to capital financing at a low cost.

Both of these perverse market incentives can challenge PJM's procurement of reliability resources when they are needed most.

V. PJM'S PROPOSED VRR CURVE COMPOUNDS RPM PRICE VOLATILITY

153. On top of this increased volatility and uncertainty, PJM is proposing a number of other changes to the VRR Curve based on Brattle's recommendations:

a. Increase the upper bound of the VRR Curve to the higher of Gross CONE or 1.75 times the Net CONE (versus the prior 1.5 assumption).

b. Change the x-axis location of the end point for the maximum price from 98.9%[26] to 99% times the reliability requirement.

c. Decrease the x-axis location of the "kink" in the VRR Curve from 101.6%[27] to 101.5% times the reliability requirement.

d. Decrease the maximum amount of reliability procured from 106.8%[28] to 104.5% times the reliability requirement.

154. Every single one of these changes steepen the VRR Curve and increases price volatility, tightening the administrative amount of reliability that can be procured at the expense of stability. The net result of these other VRR changes is a steeper demand curve, as illustrated by Figure 2 in the PJM filing letter.[29]

155. This steeper demand curve, increases the sensitivity of RPM prices to a change in Net CONE estimates, effectively magnifying the impact of Net CONE uncertainty and volatility onto RPM prices.

156. Given all of the other changes happening in the PJM market tied to energy price volatility and the transition to renewable resources that are not always available on demand, the decision to add yet even more volatility and uncertainty into the market would seem imprudent.

[26] This equals the Installed Reserve Margin ("IRM") less 1.2%
[27] This equals the IRM + 1.9%.
[28] This equals the IRM + 7.8%.
[29] PJM Filing Cover Letter, p. 15.

VI. USING THE FORWARD-LOOKING APPROACH FOR A COMBINED CYCLE INCREASES PERVERSE INCENTIVES, VOLATILITY AND UNCERTAINTY

157. PJM proposes to adopt a forward-looking E&AS Offset which, when combined with the proposed combined cycle reference unit, increases reliance on the forward-looking E&AS Offset to calculate Net CONE, magnifying the perverse market incentives.

158. Given that the forward-looking E&AS Offset is calculated using outputs from a set of proprietary algorithms, use of the combine cycle increases uncertainty compared to what the combustion turbine would generate using the forward-looking E&AS methodology.

VI.1 The IMM's presentation illustrates the implications of PJM's proposal

159. During the Fifth Quadrennial Review the IMM participated with its own estimates of Net CONE under alternative technological specifications and using historical versus the forward-looking E&AS Offset methodologies.

160. This analysis is included here to provide context for the results of my independent analysis presented in the next section, as well as to provide an insight into the calculations that have been performed by both the IMM and Brattle as part of the discussions leading up to the recommendations.

161. **Figure 13** provides a screenshot of a summary analysis presented by the IMM as part of the quadrennial review in March 2022 that compares IMM estimates to Brattle's calculations of Net CONE for a combustion turbine versus combined cycle under both the historical and forward-looking E&AS Offset methodologies.

    a. The first two tables are for a combustion turbine, the current reference unit.

    b. The second set of two tables have estimates for the 1 on 1 combined cycle being proposed as the new reference unit.

    c. The third set of the last two tables are a 2 on 1 combined cycle unit configuration that was reviewed, but rejected, as an appropriate reference unit technology.

162. These summary tables show four key findings:

    a. **Estimation Uncertainty:** The IMM's estimates differ from Brattle's, indicating uncertainty surrounding Net CONE estimates.

    b. **Impact of reference unit on Net CONE:** The proposed combined cycle reference unit significantly reduces Net CONE compared to a combustion turbine.

c. **Impact of the Forward-looking E&AS Offset:** The Forward-looking E&AS Offset significantly reduces Net CONE across all technology specifications.

d. **Volatility is higher for the Combined Cycle:** The range of Net CONE estimates is significantly higher for the combined cycle than for the combustion turbine across nearly all scenarios and regions, illustrating the greater volatility associated with moving to a combined cycle reference unit.

Figure 13: IMM Presentation of Net CONE Estimates[30]

CT Revenue Requirements Comparison: Historic and Forward EAS

CT Revenue Requirement ($/MW-Day)	IMM				Brattle			
PJM LDA	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
Gross CONE (IMM incl. major maintenance)	$369.56	$384.82	$378.68	$350.32	$287.67	$293.15	$289.32	$286.85
IMM EAS Historical (no major maintenance)	$53.34	$90.20	$113.72	$120.71	$53.34	$90.20	$113.72	$120.71
Net CONE	$316.22	$294.62	$264.96	$229.61	$234.33	$202.95	$175.60	$166.14

CT Revenue Requirement ($/MW-Day)	IMM				Brattle			
PJM LDA	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
Gross CONE (IMM incl. major maintenance)	$369.56	$384.82	$378.68	$350.32	$287.67	$293.15	$289.32	$286.85
IMM EAS Projected (no major maintenance)	$85.26	$153.85	$217.22	$233.45	$85.26	$153.85	$217.22	$233.45
Net CONE	$284.29	$230.97	$161.46	$116.87	$202.41	$139.30	$72.10	$53.40

CC Revenue Requirements Comparison: Historic and Forward EAS

CC Revenue Requirement ($/MW-Day)	IMM - 1 on 1 CC ACC				Brattle - 1 on 1 CC ACC			
PJM LDA	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
Gross CONE (IMM incl. major maintenance)	$498.42	$462.47	$461.14	$450.32	$418.26	$444.13	$399.80	$407.75
IMM EAS Historical (no major maintenance)	$116.47	$210.05	$226.67	$229.38	$116.47	$210.05	$226.67	$229.38
Net CONE	$381.95	$252.42	$234.47	$220.94	$301.79	$234.08	$173.13	$178.37

CC Revenue Requirement ($/MW-Day)	IMM - 1 on 1 CC ACC				Brattle - 1 on 1 CC ACC			
PJM LDA	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
Gross CONE (IMM incl. major maintenance)	$498.42	$462.47	$461.14	$450.32	$418.26	$444.13	$399.80	$407.75
IMM EAS Projected (no major maintenance)	$187.56	$310.89	$391.44	$395.46	$187.56	$310.89	$391.44	$395.46
Net CONE	$310.85	$151.58	$69.71	$54.87	$230.70	$133.24	$8.36	$12.29

CC Revenue Requirement ($/MW-Day)	IMM - 2 on 1 CC ACC				Brattle - 1 on 1 CC ACC			
PJM LDA	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
Gross CONE (IMM incl. major maintenance)	$377.74	$354.52	$352.07	$344.44	$418.26	$444.13	$399.80	$407.75
IMM EAS Historical (no major maintenance)	$116.47	$210.05	$226.67	$229.38	$116.47	$210.05	$226.67	$229.38
Net CONE	$261.27	$144.47	$125.40	$115.06	$301.79	$234.08	$173.13	$178.37

CC Revenue Requirement ($/MW-Day)	IMM - 2 on 1 CC ACC				Brattle - 1 on 1 CC ACC			
PJM LDA	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
Gross CONE (IMM incl. major maintenance)	$377.74	$354.52	$352.07	$344.44	$418.26	$444.13	$399.80	$407.75
IMM EAS Projected (no major maintenance)	$187.56	$310.89	$391.44	$395.46	$187.56	$310.89	$391.44	$395.46
Net CONE	$190.18	$43.63	($39.37)	($51.02)	$230.70	$133.24	$8.36	$12.29

Forward prices as of January 3, 2022

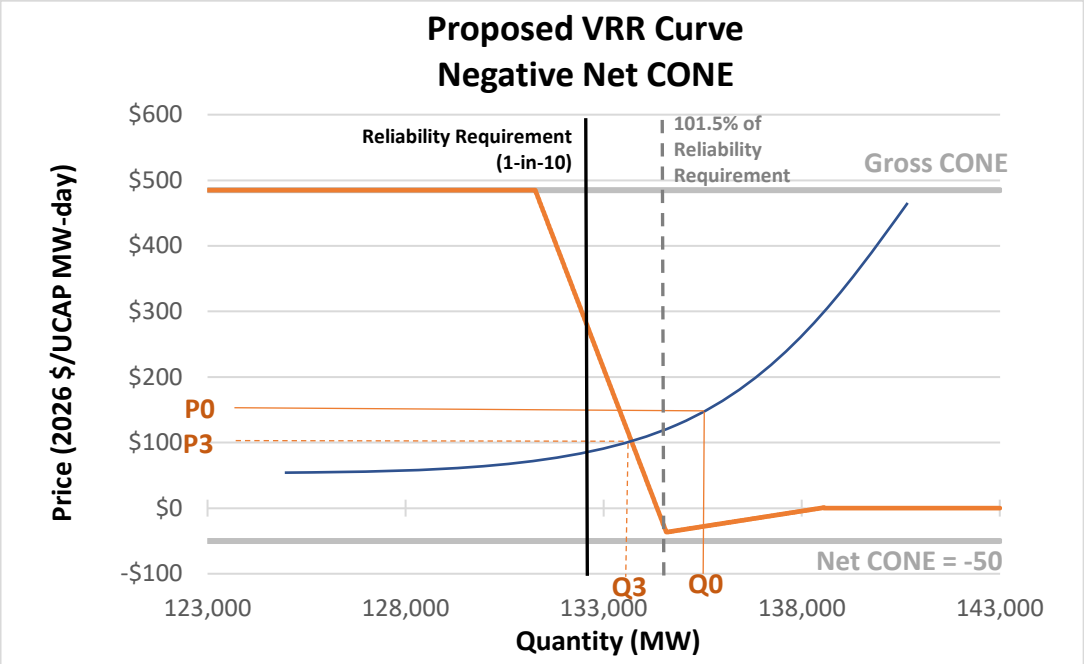
 www.monitoringanalytics.com 15 Monitoring Analytics

[30] Monitoring Analytics, IMM Proposals and Results, 2022 Quadrennial Review, March 25, 2022, pp. 14, 15, https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220325-special/item-4a---imm-cone-proposals-and-results.ashx An earlier version posted February 11, 2022 also includes negative prices and can be found here:

163. It is important to note that in the IMM's calculations, neither the historical E&AS Offset applied to a combined cycle or either the historical or forward-looking approach applied to a combustion turbine generated negative Net CONE results.[31] Although the 2 on 1 Combined Cycle is not the proposed reference unit, it illustrates the potential for negative Net CONE under the forward-looking E&AS Offset.

164. With a negative Net CONE, the VRR Curve would place the "kink" below the x-axis and generate a steeper, single sloped VRR Curve (**Figure 14**).

Figure 14: Illustration of the Impact of Negative Net CONE on the VRR Curve



165. Given the perverse pricing incentives magnified by a combined cycle, even in an extreme situation where high spark spreads represent shortages in energy markets, the shifting VRR Curve still would call for less capacity and lower RPM prices Given the placement of the "kink" below zero, the slope of the VRR Curve would cross the x-axis between 99% and 101.5% of the reliability requirement. Therefore, when capacity is needed most, the proposed RPM market would procure less than 101.5% of the RPM.

166. The IMM's estimates should be a warning that there are scenarios with a combined cycle where volatility in short-term energy markets cause the forward-looking E&AS Offset to

20220211-item-02-monitoring-analytics-micquadrennial-review-cone-ct-cc-study.ashx (pjm.com)

[31] Monitoring Analytics, IMM Proposals and Results, 2022 Quadrennial Review, March 25, 2022, p. 14.

be greater than gross CONE, thereby potentially resulting in a rate construct that assumes a negative Net CONE and a reduction in reliability resources that can be procured.

167. Furthermore, the IMM calculations indicate how much more volatile Net CONE estimates will be from year to year as energy market supply and demand conditions change using a combined cycle as a reference unit versus a combustion turbine.

168. The IMM's calculations indicate how significantly the change to a combined cycle reference unit instead of a combustion turbine will impact Net CONE. Although this arguably supports going to the combined cycle as the more economic technological solution, the volatility of Net CONE values for a combined cycle renders that conclusion suspect.

169. The higher volatility of the Net CONE for a combined cycle means that it can be higher or lower than a combustion turbine, depending on conditions in energy markets. Therefore, the lower Net CONE estimate under current conditions may simply reflect spark spread volatility.

170. The fact that the IMM could obtain negative Net CONE values using a combined cycle as the reference unit and E&AS offset estimated using futures prices illustrates extreme variability surrounding use of futures data – variability generated by both uncertainty in how to produce the E&AS Offset to match PJM's calculations and volatility tied to using futures prices. My indicative analysis, described in the next section, shows the same possibility using historical conditions.

VI.2 A backcast of the proposed changes illustrates increased price volatility

171. In order to illustrate the uncertainty and volatility associated with a combined cycle reference unit versus a combustion turbine, I performed my own estimates of net energy revenues and Net CONE using a historical look-back of what Brattle's gross CONE estimates and proposed E&AS Offset methodology would have generated for historical BRAs.

a. Instead of using PLEXOS, a proprietary model, I created a spreadsheet dispatch model that could run alternative price inputs for different PJM zones, with a representation of the historical methodology and the forward-looking E&AS Offset as proposed by PJM.

b. The analysis relies on a historical series of financial futures data procured for a limited number of monthly trade dates directly from ICE to perform the calculation for the historical BRAs.

c. Despite the lack of transparency, I used futures settlement price data to mimic PJM's proposal, and therefore rely on the ICE algorithms.

d. Only a subset of hubs that Brattle identified as being "liquid" using the metric of open interest were used; no adjustment was made for lack of liquidity.

e. Trading periods 180 days prior to the historical BRAs were used for delivery months consistent with the actual BRA delivery periods (versus 3 to 4 years out), taking advantage of near-term liquidity and illustrating what would have happened if the forward-looking E&AS Offset methodology was in place for each of those auctions.

f. Ancillary services were ignored for purposes of this analysis to isolate the impact of changing the energy methodology on Net CONE.[32]

g. Brattle's Gross CONE estimates were adopted for each zone. The Gross CONE and operational assumptions from 2026/27 were reduced by an inflation factor based on Brattle's 2.2% assumed inflation rate to bring it back to the BRA delivery period in the backcast.

172. **Figure 15** illustrates the results of the backcast associated with changing to the proposed combined cycle and the forward-looking E&AS Offset methodology for the past five BRAs for three representative zones.

173. This table provides many values that provide three main conclusions and important questions that neither Brattle nor PJM have addressed:

a. **The Forward-looking E&AS Offset significantly reduces Net CONE:** In all cases for the combined cycle and most cases for the combustion turbine, moving to the forward-looking E&AS Offset methodology significantly reduces Net CONE, with the change for the combined cycle being significantly higher than what the move to a forward E&AS Offset would have been for the existing reference unit.

Question: If rates are just and reasonable with the current E&AS methodology, what has changed to warrant such a significant reduction in the Net CONE and associated RPM prices other than moving to a combined cycle?

b. **A combined cycle reference unit significantly reduces Net CONE**: In nearly all cases moving from the combustion turbine to a combined cycle as the reference unit significantly reduces Net CONE, especially in the forward-looking methodology. This is consistent with the IMM's results displayed in **Figure 13** on page 37. Under historical prices, however, the combined cycle is not always the economic unit.

[32] In PJM's estimate for the 2026/27 delivery period, net revenues for ancillary services estimated for a combined cycle fell to less than 1 percent of the E&AS Offset, primarily due to Brattle's recommendation to drop the regulation revenues in the E&AS Offset.

Brattle claims that it proposes moving to a forward-looking E&AS Offset given the recommendation to adopt a combined cycle. However, historical prices do not support a claim that a combined cycle is always the more economic unit.

Question: If rates were just and reasonable with the combustion turbine, what has changed to warrant such a significant reduction in the Net CONE and associated RPM prices?

c. **Volatility in Net CONE is higher for the combined cycle:** Volatility as measured by the standard deviation and coefficient of variation (ratio of standard deviation to mean) is much higher for the combined cycle for each zone over the five BRAs than for the combustion turbine which offers a more stable Net CONE.

Question: If the goal of the RPM is to send a stable price signal, how does the change to a combined cycle using a forward-looking E&AS Offset achieve that goal?

Figure 15: Estimated Net CONE under the Current OATT versus PJM's Proposal[33]

COMBINED CYCLE	APS ZONE		COMED ZONE		DAYTON ZONE	
	HISTORICAL	FORWARD	HISTORICAL	FORWARD	HISTORICAL	FORWARD
BRA Auction	Net CONE	Net CONE	Net CONE	Net CONE	Net CONE	Net CONE
2024/25	$ 336.60	$ (85.29)	$ 399.89	$ 293.03	$ 371.75	$ 135.46
2023/24	$ 332.58	$ 50.69	$ 395.22	$ 259.00	$ 368.30	$ 168.53
2022/23	$ 322.06	$ 220.02	$ 388.44	$ 361.39	$ 358.24	$ 307.98
2021/22	$ 208.93	$ 214.13	$ 343.39	$ 310.19	$ 324.51	$ 285.69
2020/21	$ 123.95	$ 182.62	$ 316.24	$ 311.44	$ 294.88	$ 282.12
Average	**$ 264.82**	**$ 116.43**	**$ 368.64**	**$ 307.01**	**$ 343.54**	**$ 235.95**
Standard Deviation	**$ 94.85**	**$ 131.98**	**$ 36.94**	**$ 37.04**	**$ 32.99**	**$ 78.16**
Coefficient of Variation	**0.36**	**1.13**	**0.10**	**0.12**	**0.10**	**0.33**

COMBUSTION TURBINE	APS ZONE		COMED ZONE		DAYTON ZONE	
	HISTORICAL	FORWARD	HISTORICAL	FORWARD	HISTORICAL	FORWARD
BRA Auction	Net CONE	Net CONE	Net CONE	Net CONE	Net CONE	Net CONE
2024/25	$ 359.97	$ 117.22	$ 392.52	$ 336.24	$ 379.34	$ 266.07
2023/24	$ 354.64	$ 213.48	$ 385.68	$ 340.62	$ 373.59	$ 294.40
2022/23	$ 339.68	$ 319.70	$ 378.62	$ 374.23	$ 361.63	$ 358.41
2021/22	$ 239.76	$ 306.41	$ 357.82	$ 353.95	$ 349.50	$ 344.21
2020/21	$ 169.64	$ 271.82	$ 330.44	$ 335.67	$ 320.23	$ 323.95
Average	**$ 292.74**	**$ 245.72**	**$ 369.01**	**$ 348.14**	**$ 356.86**	**$ 317.41**
Standard Deviation	**$ 84.43**	**$ 82.75**	**$ 25.18**	**$ 16.34**	**$ 23.47**	**$ 37.44**
Coefficient of Variation	**0.29**	**0.34**	**0.07**	**0.05**	**0.07**	**0.12**

[33] APS Zone assumes PJM West and the Dominion South natural gas hub;
COMED Zone assumes PJM's Northern Illinois hub and the Chicago natural gas hub; and
DAYTON Zone assumes PJM's AEP-Dayton hub and the MichCon natural gas hub.

174. The forward-looking methodology illustrates the significant impact that volatile energy futures can play in Net CONE. For the APS Zone, the forward-looking E&AS Offset for a combined cycle would have produced a negative Net CONE for the 2024/25 BRA auction. This illustrates the impact that short-term energy market supply and demand conditions will play in determining the parameters of the VRR Curve for long-term capacity decisions.

175. This impact is not limited to current conditions, however. Going back in time to examine how dispatch using futures prices compares to dispatch using historical prices indicates that using futures prices tend to result in a higher E&AS Offset. The futures approach also results in greater year-to-year variation in the E&AS Offset compared to using historical prices. Volatility is compounded by the proposed use of a combined cycle versus the existing combustion turbine reference unit.

176. Under the forward E&AS Offset approach, estimates for a combined cycle Net CONE are more volatile than estimates for a combustion turbine Net CONE.

177. This estimate of the results that would be obtained using alternative methodologies indicates that PJM's proposed approach compounds volatility in the Net CONE estimate by changing multiple factors that impact the final estimates of Net CONE.

a. **Reference Unit:** Changing the reference unit from a combustion turbine to a combined cycle increases Net CONE estimation volatility.

b. **Forward-looking E&AS Offset:** Adopting the proposed forward-looking approach introduces greater volatility by using futures data for a limited number of trading days to project prices during the delivery period.

c. **Dispatch Model:** Adopting an optimized dispatch model approach introduces greater uncertainty and volatility due to changing market conditions and the dynamic relationship between natural gas and electricity prices.

178. The change to a dispatch model exposes the proposed E&AS Offset methodology to short-term changes in market conditions. Whereas the current methodology fixes dispatch to reflect a notional peaker plant and three years of average prices, PJM's proposed approach allows for dispatch across all hours based on the assumed heat rate of the reference unit and market conditions embedded in the assumed electricity and natural gas price relationship for 30 trading days during which very few trades occurred.

179. The smoothing function of the historical approach that the Commission found to be just and reasonable for estimating long-term market conditions no longer exists in the forward-looking E&AS Offset methodology, resulting in price swings that can be two to three times greater than what would occur with a combustion turbine.

180. By proposing all three changes at once, PJM is introducing a significant amount of volatility and uncertainty into the Net CONE estimates used to set the parameters for RPM.

VII. PJM'S PROPOSED CHANGES ARE ANTITHETICAL TO THE UNDERLYING PURPOSE OF THE RPM

181. As stated by PJM, the objective of RPM is to procure reliability by incentivizing long-term capital investment:

a. PJM's website currently states: "PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future."[34]

b. PJM refers to capacity as "Power for the future" and states, "By matching power supply with future demand, PJM's capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies."[35]

c. In a 2011 presentation on RPM, PJM states that the original intent for RPM is to add "stability and a locational nature to the pricing signal [that] provides forward investment signals."[36]

182. PJM's proposed changes to the Net CONE calculation and VRR Curve parameters, however, is not consistent with this longer-term outlook or set of capital investment objectives.

183. PJM's proposal represents a significant collection of changes, all of which increase price volatility in a market that is meant to procure long-term capital investment that requires regulatory stability.

184. PJM's proposed approach to apply a forward-looking E&AS Offset to a combined cycle reference unit introduces uncertainty into the VRR Curve as a result of reliance on proprietary databases and algorithms. The illiquid and short-term nature of the forward-looking E&AS Offset inputs also introduces significant energy market price volatility into the calculation of Net CONE.

185. Changing to a combined cycle magnifies the impact of short-term energy market changes. A combined cycle generates substantially more energy than a combustion turbine, making the Net CONE of a combined cycle much more sensitive to changes in market prices. PJM's proposal to switch to a combined cycle magnifies the volatility associated with the forward-looking E&AS Offset that responds to short-term energy market conditions and relies on illiquidly-traded hubs and proprietary algorithms.

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[34] PJM, https://pjm.com/markets-and-operations/rpm.aspx
[35] PJM, Capacity Market (RPM), https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets
[36] PJM, Reliability Pricing Model (RPM), Interconnection Training Program Module EM7, Winter 2011, p. 3.

186. By steepening the VRR Curve, PJM attempts to control the amount that can be procured to a narrowed band around the administratively-set reliability requirement. This comes at the expense of increased volatility in RPM prices which are now more dependent on short-term energy market conditions through the proposed changes.

187. As a result of PJM's proposed changes, the shape of the VRR Curve can change dramatically from one year to the next based on short-term energy market conditions.

188. Instead of serving as a stable price signal to encourage long-term investment in reliability, PJM now proposes to procure a long-term investment by relying on parameters inversely correlated with short-term energy price movements. This creates perverse pricing incentives for both entry and exit.

189. There is no financial contract that would allow generators to hedge against this increased RPM price volatility. There are no futures markets or capacity pricing products to mitigate the risk of year-over-year RPM price changes. Under the proposed changes, the RPM becomes a market with unstable, volatile, and speculative prices that cannot be hedged without physical energy production. In effect, PJM proposes to turn RPM into an energy market hedge that benefits those units that produce energy and penalizes pure capacity units that do not.

190. This systemic and asymmetrical hedging effectively favors energy-producing generators over pure reliability units, effectively pre-choosing the winners of the RPM markets on the margin. The proposed PJM changes effectively disincentivize pure capacity units from being built, increasing the cost of capacity and challenging reliability.

191. There is a reason why PJM maintained a combustion turbine as the reference unit for so long, along with other VRR Curve design features that mitigated the impact of energy price volatility on RPM market prices.

192. In effect, by introducing short-term energy price conditions into the VRR Curve parameters, and magnifying the volatility with a proposed change to the combined cycle reference unit, PJM is fouling the purpose and incentives of the RPM.

VIII. CONCLUSION

193. PJM proposes multiple changes to the RPM market that individually and combined lead to:

a. Increased uncertainty and lack of transparency surrounding RPM parameters tied to use of proprietary data sources, algorithmic futures prices, and a proprietary model for dispatch.

b. Perverse market incentives that sends a higher price signal during periods of excess capacity and a lower price signal when additional capacity is needed.

c. Increased RPM price volatility that magnifies those perverse market incentives.

d. A violation of the objectives underlying the RPM market construct to provide stable incentives to procure long-term capacity.

194. This concludes my affidavit.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER22-2984-000**

AFFIDAVIT OF TANYA L. BODELL
ON BEHALF OF THE PJM POWER PROVIDERS GROUP

I, Tanya L. Bodell, being duly sworn, depose and state that she is the Tanya L. Bodell referred to in the document titled "Affidavit of Tanya L. Bodell on Behalf of PJM Power Providers Group," that the document was prepared by her or under her direction, that she has read such testimony and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of her knowledge, information and belief in this proceeding.

Tanya L Bodell

Tanya L. Bodell

SUBSCRIBED AND SWORN to
Before me this 21 day of October 2022

Notary Public
My commission expires: 11-09-2023

Rachel Swanson

RACHEL SWANSON
Notary Public
Commonwealth of Massachusetts
My Commission Expires
November 9, 2023

Norfolk County Massachusetts

EXHIBIT-1

Tanya Bodell
Partner

StoneTurn Group LLC

Tanya Bodell, Partner, leads StoneTurn's energy offerings in business advisory services, regulatory support and expert testimony in large-stakes litigation, levering more than 25 years of experience in energy matters.

Tanya provides business advisory and expert support to clients in the energy industry, advising on business strategy, asset valuations, mergers/acquisitions, market rules, regulatory outreach and market assessments. She also provides expert testimony in insolvency, regulatory and litigation cases pertaining to the energy industry, including cost-benefit valuations and damages claimed for breach of contract, fraudulent misrepresentation, market manipulation and liability.

For the past decade, Tanya has been a regular columnist for Pennwell Publications *Electric Light & Power* magazine and wrote a regular column for two years for Wiley Publications *Natural Gas & Electricity*. Through her columns, she offers regular insights on business issues facing the energy industry.

SELECT PROFESSIONAL EXPERIENCE

ADVISORY SERVICES

Tanya interacts directly with executives, corporate boards, investors and senior management of energy companies, adding value through business strategy, market assessments, transaction support, valuations, and regulatory policy. Selected services and assignments cover all facets of the power sector, including renewables and energy storage, as well as aspects of the natural gas, liquified natural gas, coal, and oil sectors.

Business Strategy

For a number of domestic energy technology start-ups and established energy companies, Tanya develops strategy for expansion into new businesses, technologies and market segments, including advice on the regulatory structures, government support and entry strategies for investments in commercial transmission, energy storage solutions and renewable resources. Her advisory services on new entry strategy and commercialization, includes market assessments, target identification, strategic partners, mergers/acquisitions, and timing/type of potential exits under alternative commercialization strategies. Specific technologies for which Tanya has provided strategic advice include:

- **Renewable Generation:** For international companies focused on wind and solar technologies, Tanya has assisted with education, entry strategy, regional assessments, and identification of merger/acquisition targets to facilitate entry into U.S. markets.

- **Energy Storage:** For a number of energy storage technology start-ups, Tanya has served as an advisor, assisting with market valuations, cost-benefit analyses, target markets and entry strategy. The energy storage technologies that she has advised include long-duration thermal storage, battery energy storage systems, hydroelectric pumped storage, waste-to-energy systems, and hydrogen.

- **Transmission and Smart Grid Technology:** For transmission technology companies, independent transmission developers, and transmission enablers, she has identified potential investment opportunities, pathways to commercialization, and new entrant opportunities.

- **Microgrids:** For a number of municipalities, Tanya has worked with technology providers and the utilities to develop potential microgrids to improve reliability and resiliency.

- **Hydrogen:** Tanya has served as an advisor for a new hydrogen fuel producer, assisting them with understanding U.S. power sector and natural gas markets to develop an informed commercialization strategy. Her role includes tracking hydrogen hub funding and stakeholders along with facilitating introductions and meetings with other potential partnerships.

Business Valuation and Acquisition Strategy

Tanya provides independent asset valuations and acquisition strategy for investors in the energy industries.

- She serves as an independent expert to estimate the appropriate cost of capital for assets under dispute as part of regulatory, litigation and valuation projects.

- For energy storage companies, advises on market entry strategy, market benefits including price and carbon emissions reductions, portfolio of value propositions, and potential value of proposed projects.

- For developers and asset owners of generation and transmission projects, performs benefits study of the plant's impact on environmental emissions and energy prices in the region.

- Acts as an independent appraiser for valuation, transaction support, and disputes, including appraisals of traditional power generation assets, cogeneration facilities, natural gas assets, and renewable power portfolios.

- For new entrants and emerging players, values enterprises, power assets, power purchase agreements, tolling arrangements, and trade books.

- Provides utilities and independent power producers with due diligence and advice relating to power purchase agreements, contract renegotiations, merchant plant investment opportunities and valuation of non-utility generation assets.

Renewable Resources

Tanya's work for renewables includes advice to developers and expert testimony on benefits and costs of new renewable projects, as well as renewable portfolio assessments.

- Assesses value of wind farms and renewable generation assets as merchant and contracted facilities, and incorporates the impact of such assets into market dynamics.

- Possesses deep understanding of environmental attribute markets and regulations, including production tax credit, investment tax credit, net metering credits, RPS requirements. design and implementation of generation information system tracking systems and markets for renewable energy credits.

- Served as key litigation strategist for a client defending against a nearly $1 billion damages claim related to alleged breach of wind turbine supply agreements. Responsible for managing the entire project, including two testifying experts, overseeing research on markets turbine and nacelle prices, availability, market conditions, discovery and damages.

- Advised the Ontario Ministry of Science and Technology on policy to promote green power and renewable resource development.

- For a commercial company located in Massachusetts, Tanya analyzed the costs, benefits and risks of pursuing installation of solar energy arrays under the state and federal regulatory regime, assisting the

owner with soliciting potential developers.

Energy Storage

Tanya has developed strategic plans, originated business opportunities, and assessed the value of microgrids and energy storage opportunities.

- Performs market valuation of energy storage assets using market prices under different volatility assumptions and using production cost model projections, including short-term and long-duration storage technologies.
- Projects project benefits to that broader system, including reduction in electricity prices, carbon emissions and recapture of overgeneration.
- Provides updates on regulatory rules relating to energy storage facilities.
- Applies deep understanding of alternative energy storage technologies, including pumped storage, long-duration storage, batteries, flywheels and hydrogen-based storage technologies and their role in electricity markets.
- Designs high-level strategic framework and cost-effective microgrid design for municipality looking to improve its reliability and resiliency which achieving its carbon emission reduction goals.
- Assesses the potential benefits of contracted energy storage to system prices, carbon emissions and winter resiliency.

Transmission

Tanya has been involved extensively in long-distance transmission lines and independent transmission businesses, providing new entrant strategy and transaction support for investments in US commercial transmission, advising transmission developers on potential markets, customer acquisition, regulatory strategy and financing options.

- For a generation association, analyzed the sources and uses of a proposed high voltage direct current transmission line into New York City, including the potential impacts on power flows.
- For a consortium of generators, analyzed the costs and benefits associated with building a new high voltage direct current transmission line from Canada into the Northeast.

Tanya Bodell — Partner

- For a multi-billion dollar international transmission company, provided strategic advice on market structure, regulatory organization and strategy, investment opportunities, and asset acquisition opportunities.

- For a large rail company, advised on potential use of existing rights of way for development of transmission lines, including advice on specific transmission opportunities, identification of strategic regions and potential partners.

- For a multi-billion utility, advised on their commercial transmission strategy and development opportunities.

- For a multi-billion dollar oil and gas pipeline company interested in expanding their energy transportation portfolio into electric transmission, provided new entry strategy and successfully presented to the Board, launching the firm's initiative to develop a commercial transmission business in North America.

- For a large utility interested in pursuing a commercial transmission business, provided strategic advice on regions, strategic partners and target projects, including bidding strategy on acquisition of an operational transmission line.

- For the triennial rate review of a transmission upgrade in California, submitted expert testimony on the benefits of the transmission upgrade.

- For a transmission line under development in the southwest, assessed the size and potential markets for transmission service.

- For large utilities interested in developing a commercial transmission business, advised on entry strategy, potential acquisitions, and performed due diligence on specific acquisition targets.

- On behalf of an independent transmission company, assessed transmission asset acquisitions valued at over a billion dollars.

- Advised generation owner on regulatory strategy to create independent transmission company for purposes of developing high voltage interconnection (1,000 MW of capacity).

Competitive Procurement

Tanya has helped billion-dollar companies to design and implement competitive procurement processes for energy and energy assets.

- Designs and manages competitive procurement processes, including review of power procurement agreement, credit requirements, request for proposal process, and auction.

- Designs and manages transmission open season and bilateral negotiations for transmission capacity.

- Assesses long-term and short-term gas contracts in the context of hedging plays against other energy contracts, including tolling agreements and long-term power purchase agreements.

Corporate Restructuring

Tanya advises all aspects of the capital structure on valuation of power generation and delivery assets and securitization options in high-profile restructurings in the electricity industry.

- For the Oversight Committee of Puerto Rico, assessed the date of insolvency for the Puerto Rico electric utility (PREPA), the Commonwealth and a number of other government entities.

- For the ad hoc equity committee of a large renewable developer, provided valuation insight into the remaining assets and advice on potential strategies to pursue to obtain standing as an official equity committee.

- For investors in a large Texas utility with a significant competitive generation portfolio, provided pre-bankruptcy filing advice regarding generation asset valuation and impacts of proposed market changes pertaining to Interim Solution B+.

- For the unsecured creditors committee of a bankrupt portfolio of coal plants located in New York, provided industry expertise, valuation, market assessments, and settlement advice.

- For the unsecured creditors committee of a bankrupt coal plant located in New England, provided industry expertise, valuation, power contract assessment, damages calculations, market assessments, and settlement advice.

- For the bondholders of a waste coal facility undergoing restructuring in Pennsylvania, provided project valuation, assessed project cash flows and debt capacity, interfaced with the company's financial advisor, and advised on changing market conditions.

- For the Enron estate, analyzed insolvency analyses under the three legal tests: balance sheet, cash flow and capital adequacy. Analyses included assessing the tradebook for purposes of identifying debt-like transactions and performing cash flow projections of debt repayment and capital requirements. Analyzed tradebook entries, energy contracts, and hundreds of legal documents to rebook more than $3.5 billion of off-balance sheet transactions for purposes of understanding when the company was insolvent. Settlement with various parties totaled more than $6 billion.

- For a bankrupt tradebook, developed summary synopses on mark-to-market accounting and the marketable value of trade books and examines trader activities for market manipulation and non-compliance with regulatory requirements. Tanya also has analyzed tradebook entries, energy contracts, and hundreds of legal documents to rebook off-balance sheet transactions into the financial statements of a bankrupt energy market's estate.

- For a large, publicly-traded energy marketer, Tanya reviewed tradebook for wash trades and market manipulation, revalued tradebook and assessed controls on trading operations before and after conveyance.

Market Assessments and Electricity Market Design

- Tanya understands the economic underpinnings of competition, economic incentives and market rules for both competitive wholesale and retail markets. Tanya regularly performs market assessments of wholesale energy and capacity markets for market participants, including assessment of the impact of alternative market rules and regulations and strategic advice for regulatory positioning.

- Develops and directs analyses of market conditions using locational marginal pricing market models, zonal prices and industry data.

- Advises on policy recommendations concerning market design and implementation, and authors white papers and expert testimony regarding research and findings.

- Economic expert to market participant trade associations across multiple northeast electricity markets on market rule changes submitted to FERC, including for ISO-NE and PJM.

- Served as a key advisor to the Singapore Public Utilities Board (subsequently Energy Markets Authority) on developing a competitive wholesale and retail electricity market, including market rules, licenses and codes (2000-2004) and primary advisor and project manager to the Ontario Market Design Committee, Ontario Energy Board, Ministry of Energy, Science and Technology and market participants on competitive market design, regulatory structure, environmental policy and risk management (1998 - 2001).

LITIGATION/REGULATION

Tanya has significant experience in high-stakes litigation in which hundreds of millions of dollars are at risk. She has played a key role in cases arbitrated, mediated, litigated, and heard before regulatory agencies, providing litigation support including assessment of business damages and lost profits, market context, expert testimony, economic arguments in legal filings, and settlements. From 2008 to 2011, she served a three-year term as Vice Chair of Standing Committee for the International Centre for Expertise at the International Chamber of Commerce. Below are selected examples of cases in which she has provided expert support.

Contract Dispute

- Tanya served as the testifying expert on industry context pertaining to firm and non-firm electricity products in a dispute between two large hydroelectric power producers.

- Served as the expert witness on industry context in a contract interpretation case between an electric cooperative and municipal electric company who jointly held rights to the output of a large coal generation plant worth hundreds of millions of dollars.

- For various industry clients, reviewed more than three dozen power purchase agreements to advise on contract renegotiations, merchant plant investment opportunities and valuation of non-utility generation acquisitions.

- For a waste coal facility in Pennsylvania, served as the independent appraiser of the facility to assess the fair market sales value under the remainder of the power purchase agreement and as a merchant plant.

- For a coal plant in Connecticut undergoing contractual restructuring, assessed the value of the facility under the existing power purchase agreement, a proposed tolling agreement, and as a merchant facility.

- For the counterparty to a long-term power purchase agreement with the California Department of Water and Power, reviewed publicly-available contracts and settlements to advise on potential contract restructuring positions.

- For a potential purchaser of a cogeneration project in Oklahoma, performed a market study to assess the regulatory regime and other aspects of the market that could affect the value of the investment, including future gas and electricity price projections.

- For an owner of a cogeneration project in Michigan, analyzed a proposed back-to-back transaction involving the power purchaser and a third party to determine whether the proposed agreement posed additional risks for the project. The analysis included review of the purchaser's stranded cost calculations and regulatory filings, as well as a detailed assessment of the two contracts and associated project documents.

- For a Maryland utility, calculated stranded costs associated with its power purchase agreement and determined potential settlement negotiation positions and strategies that the utility could take with respect to buying down the contract.

- For a Texas cooperative in a power purchase agreement with a cogeneration project, analyzed potential renegotiation positions, including the potential for a buy-out and buy-down of power prices.

- In a dispute over interpretation of the terms of a cogeneration contract in Florida, supported expert testimony on the application of the Public Utility Regulatory Policy Act (PURPA) to the contract. The analysis included a survey of all publicly available non-utility generation project contracts.

Tanya Bodell — Partner

Damages

- For a transmission owner being sued for failure to operate in accordance with standard utility practice, critiqued the plaintiff's expert analysis and performed a damages calculation of the opportunity cost of lost sales associated with the transmission line outage under prices that would have occurred if the plant had been operating.

- In a lawsuit between an electric utility and a cooperative that served multiple load serving entities, assessed the value of the excess energy the utility supplied to the load serving entities due to their breach of the supply contract.

- In a dispute between a large hydroelectric power producer and natural gas independent power producer in the Pacific Northwest over damages exceeding $1 billion, reproduced the independent power project's pro-forma and calculated lost profits to the project under various scenarios including alternative electricity and gas prices and water conditions. Developed the analysis of the required return on equity for highly leveraged non-utility generation projects, including the equity, debt, and financial Betas.

- In a dispute over interpretation of the terms of a power purchase agreement in New Jersey, calculated lost profits under alternative interpretations.

- In a contractual dispute between a U.S. electric utility and qualifying facility in Pennsylvania, analyzed the financial viability of the cogeneration project for a temporary restraining order proceeding, supported the expert testimony of the damages expert and assisted counsel for deposition and cross-examination questions.

- For an electric utility suing contractor for over $55 million over failure to install a fire protection, calculated impact on business due to replacement power costs incurred while the coal plant was down, a key aspect of the damages claim. Coordinated with other experts on related matters including project schedule and appraisal.

- For multiple litigations concerning Westinghouse nuclear steam generator product liability cases in which damages claims exceeded $500 million per case, developed damages approach and calculated alternative damages tied to liability case. Repeated and adjusted analytical approach for four of the

ten lawsuits brought against Westinghouse by electric utilities, drafted expert reports, provided document review and deposition questions to counsel, and advised on strengths and weaknesses of case using ex-ante and ex-post approaches.

Tax Litigation

- In a claim concerning proper tax treatment of a contingent debt instrument, defended client against IRS investigation. Analyzed contingent debt instruments in the context of a 20-year, multi-billion dollar coal purchase agreement, drafted expert reports, and advised counsel on depositions.

- In an IRS claim concerning excessive retention of earnings by a privately-held marine transportation business, analyzed working capital and investment cash needs to show that the retained earnings were required to meet legitimate business purposes.

EXPERT TESTIMONY

Tanya has testified on a number of matters in the energy industry, focusing on economic analyses, cost-benefit analyses, and estimations of damages.

- On behalf of Kern Oil, prepared an economic report to evaluate claims made by Environmental Protection Agency in its December 7, 2021 Proposed Denial of Petitions for Small Refinery Exemptions related to the implications of Renewable Fuel Standard ("RFS") compliance requirements on a small refinery operating in central California titled, "Financial and Market Assessment of Renewable Fuel Standard Requirements on Kern Oil & Refining Company (EPA ID #5038)," 7 February 2022.

- On behalf of Morongo Transmission LLC, submitted expert testimony to FERC regarding the differential risks of their share of a transmission project over existing rights of way in Southern California compared to the risk of the partnering utility in support of transmission return on equity adders, Federal Energy Regulatory Commission, Docket No. ER21-669-000, "Prepared Direct Testimony of Tanya L. Bodell," December 15, 2020.

- On behalf of NRG Power Marketing, LLC, submitted expert testimony to FERC regarding the ISO-NE proposal to provide interim compensation for generation resources with inventoried fuel, Federal

Energy Regulatory Commission, Docket No. ER19-1428-000, "Prepared Direct Testimony of Tanya L. Bodell," April 15, 2019.

- Prepared in Support of Comments filed on the Draft Environmental Impact Statement for the Coastal Plain Oil and Gas Leasing Program, 83 Fed. Reg. 67337 (Dec. 28, 2018) by the Attorneys General of States of Washington, Delaware, Oregon, Maine, Maryland, Michigan, Minnesota, New Jersey, New York, North Carolina, Rhode Island, Vermont, the Commonwealths of Massachusetts, Pennsylvania, and Virginia, and the District of Columbia, "Economic Assessment of Proposed Oil and Gas Lease Sales In the Arctic National Wildlife Refuge Coastal Plain," March 2019.

- On behalf of Calpine Corporation Vista Energy Corporation and Bucksport Generation, LLC (the Generator Intervenors) before the Maine Public Utility Commission, Docket No. 2017-00232.

  "Prepared Direct Testimony of Tanya L. Bodell," submitted April 30. 2018.

  "Prepared Surrebuttal Testimony of Tanya L. Bodell," submitted August 17, 2018.

  "Prepared Corrected Supplemental Testimony of William S. Fowler and Tanya L. Bodell," Submitted December 24, 2018.

- Prepared Remarks of Tanya L. Bodell regarding Proposed Support for New Jersey Nuclear Plants before the New Jersey Senate Environment and Energy and the Assembly Telecommunications and Utilities Committee, State House Annex, December 20, 2017.

- On behalf of the P3 Group, Before the Federal Regulatory Committee, PJM Quadrennial Review, "Affidavit of Tanya L. Bodell," Docket No. ER19-105-000.

- American Arbitration Association, Dominion Nuclear Connecticut, Inc. vs. The Connecticut Light and Power Company, Case No. 01-16-0000-6412, "Prepared Direct Testimony of Tanya Bodell on Behalf of the Connecticut Light and Power Company," August 17, 2017.

- On behalf of the New England Power Generators Association, Exhibit NPG-4, Before the Federal Energy Regulatory Committee, Docket No. ER17-795-000.

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- Massachusetts Electric Company and Nantucket Electric Company each D/B/A National Grid, Docket No. 1605.

  "Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," June 20, 2016.

  "Surrebuttal Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," July 18, 2016.

- NSTAR Electric Company and Western Massachusetts Electric Company D/B/A Eversource Energy, Docket No. 15-181

  "Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," June 13, 2016.

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- In the Matter of Hydro-Québec v. Churchill Falls (Labrador) Corporation Limited, Province of Québec, District of Montréal, Superior Court, N: 500-17-078217-133.

  "Continuous Energy: An Overview of Contemporaneous Industry Context," July 10, 2015.

  "Interruptible Power: An Overview of Industry Context and CF(L)Co's Ability to Sell," July 3, 2015.

- Benefits analysis of the Towantic Energy Center, Testimony before the Connecticut Siting Council, Docket No. 192: An Application by Towantic Energy, LLC For a Certificate of Environmental Compatibility and Public Need for the Construction, Maintenance and Operation of a Proposed Electric Generating Facility Located North of the Prokop Road and Towantic Hill Road Intersection in the Town of Oxford, Connecticut Petition of CPV Towantic, LCC (f.k.a. Towantic Energy, LLC) to Reopen and Modify the Decision in Docket No. 192 Due to Changed Conditions. Report submitted October 2014 in conjunction with Concentric Energy Advisors, Inc.

- "Analysis and Cost Comparison of Renewable Power in California," Testimony before the Little Hoover Commission, Sacramento, CA, February 28, 2012.

- "Expert Report of Tanya L. Bodell," In the Matter of Arbitration Between Big Rivers Electric and City of Henderson Utility Commission d/b/a Henderson Municipal Power and Light, Defendants, American Arbitration Association Re: 52-198-00173-10, August 24, 2011.

- "Prepared Direct Testimony of Tanya L. Bodell on Behalf of Atlantic Path 15, LLC," Before the Federal Energy Regulatory Commission, Atlantic Path 15, LLC, Docket No. ER11-2909-000, submitted February 18, 2011.

PUBLICATIONS

Column in Pennwell Publications

- "Driving towards net zero: How the Inflation Reduction Act can move your organization ahead," Power Grid International, September 2022.
- "The Almighty Load: How Electricity is Finding a New Religion," November/December 2019
- "Beware the Green Badge of Courage," September/October 2019
- "The Role of Retail in Renewables" July/August 2019
- "The Story on Storage: Is it Truly Charging Ahead?" May/June 2019
- "Hey Google! How Much does my Energy Cost?" March/April 2019
- "Realizing Carbon Reduction Goals: Assessing the Merits of Carbon Tax," January/February 2019
- "The Evolution of Resiliency: Will the Frog Turn into a Prince?" November/December 2018
- "Imagine a Market that . . ." September/October 2018
- "Is the Great Experiment of Wholesale Electricity Competition Ending?" May/June 2018
- "Leveling the Playing Field for Storage: Can Markets Figure It Out?" March/April 2018
- "Big Data, Bit Coin and Blockchain: How will Energy Cash In?" January/February 2018
- "Resistance to Resilience: ISO/RTO Response to DOE's NOPR," November/December 2017
- "Is your SCADA System Safe?" September/October 2017
- "So What's in Your Grid Modernization Plan?" July/August 2017
- "Nuclear Friction: Challenging the Economic Rationale of State Support," May/June 2017

- "Valuing Lost Load: How the Economics have Changed," March/April 2017
- "Digitizing Electrons: How are You Incorporating the Digital Economy into Utility Operations?" January/February 2017
- "What You Can Do to Decrease Operational Risk Part II: Securing your Supply Chain," November/December 2016
- "How Operational Risk is Increasing and What you Can Do About It: Part I," September/October 2016
- "Living on the Edge: Seeing Things in a Different Way to Transform the Grid," July/August 2016
- "Listening to the Supremes: Impacts of Judicial Decisions on Power Markets," May/June 2016
- "When will Oil Prices Recover? Three Economic Theories Provide Different Answers," January/February 2016
- "The Internet of Things: Where the Power Sector Connects," November/December 2015
- "A Synopsis of Changes in the Finalized Clean Power Plan," September/October 2015
- "Priming the Power Sector: Will Performance Pay?" July/August 2015
- "Pay Attention to the Man behind the Meter," March/April 2015
- "2015 in Preview: Harbingers Ring in the New Year," January/February 2015
- "What do Lower Oil Prices Mean for the Power Sector?" November/December 2014
- "For Sail: Mega Merger Tactics in the Electricity Industry," September/October 2014
- "Who's on First? Ongoing Challenges to FERC's Jurisdiction," July/August 2014
- "How Big Data is Becoming a Bigger Deal for the Power Sector," May/June 2014
- "Transformative Technologies to Watch During the Next 2 Years," March/April 2014
- "Why Google Bought Nest for $2.3 Billion," January/February 2014

Column in Wiley Periodicals, Inc., a Wiley Publication

- "Shale's Big Impact on US Manufacturing: Boom or Bust?" November 2014
- "Why Virtual Pipelines Transporting CNG are becoming a Reality," August 2014
- "Parallel Play: Coordinating Natural Gas and Electricity Markets," May 2014
- "Understanding the Recent Volley in Natural Gas Prices," March 2014
- "Outlook – Spark Spreads, Dark Spreads, and Bed Spreads Showing Cutthroat Competition," January 2014
- "NGLs versus LNG: The Fight of the Century," November 2013
- "Natural Gas Could Bring Overseas Jobs Back to the United States," October 2013
- "Pop Go Gas Prices: Has the Market Recovered?" July 2013

- "Waste Makes Haste: Low-Cost Power Plants Scramble to Keep Pace," May 2013
- "Price Impacts of Regulating the Worldwide Fracking Frenzy," March 2013
- "Natural Gas Challenges King Coal: Check or Checkmate?" January 2013
- "A Midsummer Night's Dream: Why Natural Gas Prices Still Sleep," November 2012
- "The Yin and Yang of Natural Gas Prices and Renewable Resources," September 2012
- "Electricity and Natural Gas Dance: It Takes More than Two to Contango," May 2012

Speaking and Presentations

Tanya is an established speaker and moderator at industry conferences, offering market insights and identification of strategic opportunities for attendees, a selection of which is below:

- "Energy Outlook," MFG2021+MT Forecast Conference, November 4, 2021
- "The Increasingly Uncooperative Oil Industry," MT Forecast Conference, October 27, 2020
- "Projecting the Pace of a Renewable Resource Revolution," MT Forecast Conference in pre-recorded session, October 27, 2020
- "Tapping into the Power of Offshore Wind," Presentation to the Connecticut Power and Energy Society and New England Women in Energy and Environment, September 11, 2019
- "The Ever-Tightening Convergence of Power, Oil, and Gas," MT Forecast Conference, October 11, 2018
- "Ever-Expanding Opportunities in Alternative Energy," MT Forecast Conference, October 11, 2018
- "Evolving New England Energy Markets and what it Means for Consumers," New England Consumer Liaison Group, March 3, 2018
- "Natural Gas Storage in New England and the Impact of LNG on Winter Prices," New England Association of Energy Engineers, January 5, 2016
- "New England Pipeline and Transmission Infrastructure: Recent Studies," New England Electricity Restructuring Roundtable, November 20, 2015
- "Two Perspectives on the Clean Power Plan: New England vs. Texas," Infocast 2nd EPA Clean Power Plan Implementation Summit Multi-State Perspectives, Plans and Implications of 111(d), October 20, 2015
- "Future of Energy Development: Energy Trends and Opportunities," Global Forecasting and Marketing Conference, Association for Manufacturing Technology, October 14, 2015
- "Energy Trends and Opportunities," United States Cutting Tool Institute, Spring Meeting, May 3, 2015

- "Status of Proposed Rules," EPA Clean Power Plan Implementation: Multi-state Perspectives, Plans and Implications of 111(d), April 1, 2015
- "Energy Trends and Opportunities for the Heat Exchange Industry," Heat Exchange Institute, March 22, 2015
- "Economic Impacts of Environmental Regulations on ERCOT: Bringing it down to dollars and sense," Infocast EPA Clean Power Plan Implementation (Conference Chair and Speaker), February 25, 2015
- "Capital Expenditures in the Energy Industry," American Manufacturing Technologies Global Marketing and Forecasting Conference, October 15, 2014
- "The Future of Energy in New England," Northeast Energy Commerce Association Annual, May 14, 2014
- "Impacts on Texas Plant Valuations and Potential M&A," Infocast ERCOT Market Summit (moderator) and Pre-Summit Forum (chair and speaker), February 25, 2014
- "Energy Trends: Why Jobs, Capital Investment and Trade are Heating Up," Association for Manufacturing Technology 2013 Global Forecasting and Marketing Conference, October 16, 2013
- "Energy Trends: Pricing Trends in the Midwest," Infocast Black Gold Conference, September 20, 2013
- "Energy Markets: Pricing Trends in the Midwest," Infocast Reshoring Summit: Brining Manufacturing back to the U.S., March 12-13, 2013
- "The New Dynamics of Integrated Energy Markets," with Jamie Heller and Alan Herbst, Infocast Webinar, November 15, 2012
- "Gas-fired Power Generation as a Driver for New Demand and Pipelines," Marcellus and Utica Infrastructure Summit, Infocast Conference, Pittsburgh, PA, July 12-13, 2012
- "Competitors or Collaborators? Exploring the Interplay between Renewable Energy & Other Fuel Sources," Wall Street Renewable Energy Finance Forum, New York, June 19-20, 2012
- "Executive Briefing: Power Market Trends Impacting the Value of Power Assets," Executive Session Moderator, Power Generation Asset Financing Summit, New York, May 19-21, 2012
- "Trends Shaping the Future," Projects & Money, New Orleans, LA, January 18, 2012
- "A Brief Review of New Institutions and Structures in the Electricity Industry," Presented to the GEMI Power Conference, Houston, Texas, June 29, 2006

PROFESSIONAL AFFILIATIONS / OTHER

- Northeast Energy Commerce Association, President Emeritus

- New England Women in Energy and the Environment
- International Chamber of Commerce, Vice Chair, Center for Expertise
- Energy Bar Association, Non-legal Member
- Town of Cohasset
  Alternative Energy Committee, Chair (2010 – 2013; 2019 – present)
  Advisory Committee (2013 - 2019)

PREVIOUS EXPERIENCE

- Energyzt, Executive Director
- FTI Consulting, Managing Director
- Charles River Associates, Inc. (CRA International), Vice President/Principal
- Putnam, Hayes & Bartlett, Principal/Senior Associate/Associate

EDUCATION

- MBA, Sloan Fellow, Massachusetts Institute of Technology
- MPP, Harris School of Public Policy, University of Chicago
- B.A., Mathematical Economics, Pomona College