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September 30, 2022

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

Re: *PJM Interconnection, L.L.C.*, Docket No. ER22-2984-000
Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff") to revise certain Reliability Pricing Model ("RPM") auction parameters that PJM is required by the Tariff to review every four years through an analysis and stakeholder process. In particular, this filing proposes adjustments to the existing Variable Resource Requirement ("VRR") Curve.[1] As demonstrated in this filing, the probabilistic simulation modeling required by the Tariff for these RPM reviews estimates that the proposed curve will result in continued satisfaction of resource adequacy standards at a lower cost compared to retention of the current VRR Curve.

Consistent with the quadrennial nature of this periodic review and the PJM Tariff, PJM proposes to implement the revised VRR Curve, starting with Base Residual Auction associated with the 2026/2027 Delivery Year. PJM requests that the enclosed revisions become effective on December 1, 2022, which is 62 days after the date of this filing. Such an effective date will provide sufficient notice to Market Participants in advance of all pre-auction deadlines for the Base Residual Auction associated with the 2026/2027 Delivery Year.

I. INTRODUCTION AND SUMMARY

Under the Tariff, PJM and its stakeholders undertake a quadrennial review of the shape of the VRR Curve[2] used to clear the RPM Auctions and key inputs to that curve, i.e., the Cost of New Entry ("CONE")[3] by a representative new power plant and the Net Energy

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[1] All capitalized terms that are not otherwise defined herein have the meaning defined in the Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), or the Reliability Assurance Agreement among Load Serving Entities in the PJM Region.

[2] Tariff, Attachment DD, sections 5.10(a)(i)–(iii).

[3] Tariff, Attachment DD, section 5.10(a)(iv).

and Ancillary Services ("EAS") Revenues[4] that plant would be expected to earn in the PJM markets.

Reflecting the outcome of that Tariff-prescribed process, and after consideration of the independent review by The Brattle Group ("Brattle") and feedback from stakeholders, the PJM Board directed PJM to submit this filing revising the PJM Tariff to:

- update the definition of the Reference Resource to be a combined cycle ("CC") power plant;
- update the estimate of the Gross CONE, based on a detailed comprehensive analysis of the construction, operation, and capital costs of the Reference Resource CC power plant;
- revise the escalation rate used to annually adjust the Gross CONE estimate in the years between quadrennial reviews;
- steepen the downward-sloping VRR Curve by (1) maintaining price cap set at the greater of gross CONE or a multiple of Net Cost of New Entry ("Net CONE"), but increasing the Net CONE multiplier from 1.5 to 1.75, (2) reducing the price at which the second point (i.e., the "kink") in the curve appears based on the lower Net CONE associated with a CC Reference Resource, and the first point on the curve from the PJM Installed Reserve Margin ("IRM") less 1.2% to the PJM Reliability Requirement less 1%, and (3) moving the last point (i.e., the "foot") of the curve substantially to the left, i.e., from the PJM IRM plus 7.8% to the PJM Reliability Requirement plus 4.5%; and
- update the methodology for determining the EAS revenue offset for the Reference Resource from a historical approach to a forward-looking approach the Commission previously found just and reasonable for the PJM Region.

II. TARIFF CHANGES RESULTING FROM THE QUADRENNIAL REVIEW OF THE VRR CURVE AND ITS PARAMETERS

A. Background.

The Tariff requires that for the 2018/2019 Delivery Year and "for every fourth Delivery Year thereafter," PJM "shall perform a review of the shape of the [VRR] Curve . . . . based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis."[5] If, as a result of that review, PJM proposes that the VRR Curve shape be modified, it must present its proposal to PJM Members "on or before May 15, prior to the conduct of the Base Residual Auction [("BRA")] for the first Delivery Year in

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

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

which the new values would be applied."[6] After the PJM Members review any such proposed change, they are required to vote to "(i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31" of that year.[7] The PJM Board then will consider any proposed modification to the VRR Curve shape, and PJM must file any changes to the VRR Curve shape approved by the PJM Board with the Commission by October 1 of that year.[8] The Tariff prescribes the same process, with the same deadlines, for review of, and consideration of possible changes to, the CONE values and the net EAS revenue offset methodology.[9]

This filing represents the product of PJM's fifth periodic review of the VRR Curve and its parameters and inputs.[10] PJM's last quadrennial review updated the VRR Curve and its parameters effective with the 2022/2023 Delivery Year. Given the Tariff-stated quadrennial nature of the review, PJM and its stakeholders reviewed the VRR Curve and its parameters for the 2026/2027 Delivery Year.

For this review, PJM again retained an independent consultant, Brattle, to assist with the quadrennial review, along with a second consulting firm, Sargent & Lundy ("S&L"), to lend their expertise on generation plant cost estimates. Brattle conducted one study entitled the Fifth Review of PJM's Variable Resource Requirement Curve ("2022 VRR Curve Study");[11] Brattle and S&L conducted a second study entitled PJM CONE 2026/2027 Report ("2022 CONE Report");[12] and Brattle and S&L also provided their expertise and experience on an appropriate approach for estimating wholesale EAS revenues for the Reference Resource.[13]

Based on these analyses and recommendations from the independent consultants, PJM is proposing Tariff changes to the VRR Curve shape, the Reference Resource, the CONE values, and the net EAS revenue offset methodology for implementation beginning with the November 2023 BRA associated with the 2026/2027 Delivery Year.[14]

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

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

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

[9] Tariff, Attachment DD, sections 5.10(a)(vi)(C)–(D).

[10] Prior periodic reviews were filed in Docket Nos. ER08-516, ER12-513, ER14-2940, and ER19-105.

[11] *See* Attachment C, Affidavit of Kathleen Spees and Samuel A. Newell ("VRR Curve Aff.") (the 2022 VRR Curve Study is included as Exhibit No. 2 to Attachment C).

[12] *See* Attachment D, Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. ("Brattle/S&L CONE Aff.") (the 2022 CONE Report is included as Exhibit No. 2 to Attachment D).

[13] *See* Attachment E, Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. ("Brattle EAS Aff.").

[14] For a variety of reasons, PJM's normal capacity auction schedule of holding the BRA three years in advance of the Delivery Year have been upset, resulting in condensed auction timelines and holding BRAs closer than three years to the Delivery Year. As a result, while traditionally, the BRA for the 2026/2027

Notably, in this quadrennial review, PJM and its independent consultants actively engaged with stakeholders to solicit feedback before analysis had even begun and continued after Brattle's issuance of the final reports. As a result, Brattle's recommendation for this quadrennial review, and ultimately PJM's adoption of the independent expert's recommendation, was largely informed and shaped by stakeholder feedback.

Relying on the outcome of the independent consultant's reports, PJM proposed its recommendations to the PJM stakeholders at the May 11, 2022 Market Implementation Committee.[15] Thereafter, PJM's recommendations, as well as alternative stakeholder recommendations, were discussed and developed at numerous stakeholder meetings, culminating in a stakeholder vote at both the Markets and Reliability Committee ("MRC") and Members Committee on August 24, 2022. The MRC considered and voted on the PJM staff recommendations and three stakeholder-developed alternatives. Ultimately, PJM's proposal received the most votes in favor among three other alternative packages considered by the PJM stakeholders.[16] On the same day, the Members Committee adopted the MRC voting results.

In accordance with the Tariff, the PJM Board then met on September 1, 2022, to consider the PJM staff recommendations and stakeholder input, and directed PJM to submit the Tariff changes set forth in this filing.

B. VRR Curve Shape.

1. Background and Standards for Review of Capacity Demand Curves.

The VRR Curve is an administratively determined demand curve that is used, in combination with the supply curve formed from capacity supplier Sell Offers, to clear the RPM Auctions. The 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 CONE[17] reflected as $/MW-day (on the price axis) and the target reliability requirement (on the megawatt

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Deliver Year would be held in May 2023, it is currently scheduled to be held in November 2023. *See PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,122, at P 7 n.15 (2022).

[15] Melissa Pilong, *Quadrennial Review of VRR Curve Parameters: PJM Preliminary Recommendations*, PJM Interconnection, L.L.C. (May 11, 2022), https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220511/item-08b---quadrennial-review---pjm-preliminary-recommendations.ashx.

[16] PJM's proposal received a sector-weighted affirmative vote of 2.583 out of 5. Sector-weighted support for the other three proposals ranged from 1.079 to 2.047 out of 5.

[17] Net CONE is calculated by subtracting from CONE (which represents the levelized capital costs and fixed operations and maintenance ("O&M") expenses of a new plant) the net EAS revenues (the net revenues such a plant could be expected to earn in the PJM energy and ancillary services markets). *See* Tariff, Definitions-L-M-N.

quantity axis).[18] Higher prices (above Net CONE) are associated with capacity shortage conditions (generally below the target reliability requirement) and lower prices are associated with excess capacity conditions. The current VRR Curve produces the highest price when capacity is 1.2 percentage points below the approved IRM (or lower). The current effective Tariff sets that price as 1.5 times the Net CONE.[19]

The current VRR Curve is shown in simplified form in Figure 1 below, with price on the vertical axis and quantity on the horizontal axis. The VRR Curve has three linear segments, each extending down and/or to the right from the point where the immediately preceding segment ends. First, the price cap forms a horizontal segment at 1.5 times Net CONE, applying whenever cleared capacity is 1.2% or more below the IRM target.[20] The second line segment slopes down and to the right, ending at the point where price is 0.75 times Net CONE and the cleared quantity of capacity is at IRM plus 1.9%.[21] The third segment slopes down more gradually, ending at the point where price equals zero and the cleared capacity exceeds the IRM by 7.8%.[22]

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[18] Capacity levels are on an "unforced capacity" basis, i.e., discounted for expected forced outages.

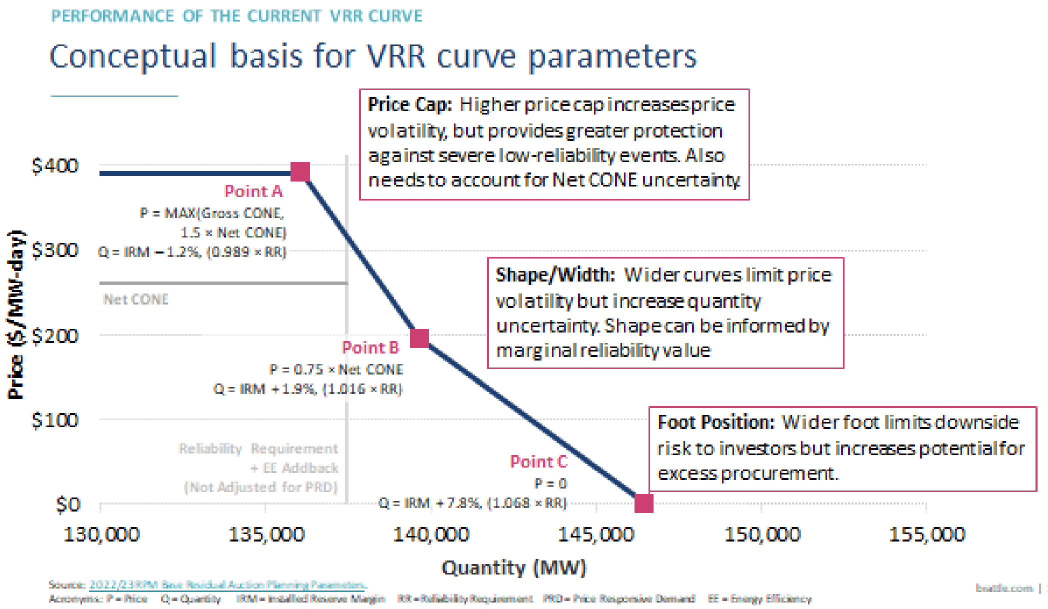
[19] To protect against a collapse in demand when the EAS revenue offset is high or against uncertainty in the Gross CONE value, the cap is set at Gross CONE if Gross CONE is greater than 1.5 times Net CONE. That is, if the EAS revenues are very high and well above gross CONE, the resulting demand curve would be very low and would produce very low capacity revenues. *See ISO New England, Inc.*, 147 FERC ¶ 61,173, at P 24 n.31 (2014). For simplicity of presentation, this contingency is not depicted in the demand curve graphs included in this transmittal. To be clear, however, this fallback reliance on Gross CONE under very high EAS conditions will remain an attribute of the VRR Curve under PJM's proposal in this filing.

[20] *See* Tariff, Attachment DD, section 5.10(a)(i) (see "point (1)" in the provision "For the 2022/2023 Delivery Year and subsequent Delivery Years, . . .").

[21] *See* Tariff, Attachment DD, section 5.10(a)(i) (see "point (2)" in the provision "For the 2022/2023 Delivery Year and subsequent Delivery Years, . . .").

[22] *See* Tariff, Attachment DD, section 5.10(a)(i) (see "point (3)" in the provision "For the 2022/2023 Delivery Year and subsequent Delivery Years, . . .").

Figure 1:
Current PJM VRR Curve



The Commission has repeatedly accepted downward-sloping, administratively determined demand curves for capacity markets, citing the advantages of such curves. For example, when the Commission first approved a VRR Curve for RPM in 2006, it found that a downward-sloping curve was reasonably expected to:

- properly reflect the additional reliability benefits of incremental capacity above the IRM target;[23]
- "reduce capacity price volatility and increase the stability of the capacity revenue stream over time" because "with a sloped demand curve, as capacity supplies vary over time, capacity prices would change gradually;"[24]
- "render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost;"[25] and
- "reduce the incentive for sellers to withhold capacity in order to exercise market power when aggregate supply is near the Installed Reserve

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[23] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006), *order on reh'g*, 119 FERC ¶ 61,318 (2007).

[24] *Id.* at P 75.

[25] *Id.*

> Margin" because "withholding would result in a smaller increase in capacity prices" and thus "would be less profitable."[26]

The Commission has consistently reaffirmed its support for RPM's sloped demand curve, including in its 2014 order on PJM's third periodic VRR Curve review, finding it "appropriate for Annual Resources to face a sloped demand curve and obtain the associated benefits"[27] that the Commission has "seen . . . from the use of a sloped demand curve, such as . . . reduc[ed] price volatility and financing costs."[28]

The Commission has explained that "[t]here may be a number of just and reasonable methods for determining the slope of the demand curve" and "[t]he derivation of the slope of the demand curve is at least in part subjective and cannot be reduced to simple metrics."[29] Demand curve design typically requires a balancing of "multiple considerations" such as "reducing price volatility, susceptibility to the exercise of market power, frequency of low reliability events, and [in addition to satisfying over the long-term a 1 event in 10 years Loss of Load Expectation ("LOLE"),] avoiding falling below a 1-in-5 LOLE in any individual time period."[30]

2. PJM and Its Independent Consultants Followed the Same Approach the Commission Has Endorsed in the Past to Evaluate Possible Changes to the VRR Curve.

For this latest review and update to the VRR Curve, PJM followed the same type of approach that the Commission has previously accepted for PJM, New York Independent System Operator, Inc., and ISO New England Inc. ("ISO-NE"). In their comprehensive independent review, Brattle:

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[26] *Id.* at P 76. *See also Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1240 (D.C. Cir. 2005) (affirming use of sloped demand curve for forward capacity auctions and finding that balancing of short-term costs against long-term benefits is within Commission's discretion); *N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, at P 13 (2003) ("*NYISO*") (agreeing with the New York Independent System Operator, Inc. ("NYISO") that demand curve proposal will "encourage greater investment in generation capacity;" "improve reliability, by reducing the volatility of ICAP revenues;" and "reduce the incentive for suppliers to withhold ICAP capacity from the market.").

[27] *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,052, at P 66 (2014).

[28] *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,052, at P 66; *see also ISO New England*, 147 FERC ¶ 61,173, at P 29 ("We further find that the sloped demand curve represents an important improvement to the FCM, as it will address some of the challenges presented by the use of a vertical demand curve in previous auctions, including, among other things, the Commission's concerns regarding price volatility and the administrative pricing provisions.").

[29] *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 111; *see also NYISO*, 103 FERC ¶ 61,201, at P 17 ("Determining the specific parameters . . . e.g., the slope and position of the Demand Curve . . . requires some measure of judgment, since there has been no experience with this new mechanism.").

[30] *ISO New England*, 147 FERC ¶ 61,173, at P 29.

- identified the objectives to be served by a VRR Curve (e.g., procuring sufficient resources to maintain resource adequacy, limit customer costs, manage price volatility, and mitigate susceptibility to market power) to provide the foundation and metrics for an assessment of alternative curve designs;[31]
- reviewed the existing VRR Curve on a qualitative basis, by carefully considering the components and features of the existing curve and their likely effectiveness in advancing the identified objectives;
- built on the prior market simulation analyses of demand curves by integrating data and experience from PJM's implementation of RPM, including a locational clearing algorithm, supply curves shaped like those seen in the RPM auctions, and plausible variations in supply, demand, and other auction inputs;
- applied a Monte Carlo simulation analysis to quantify the probability that the existing and proposed alternative VRR Curves will satisfy reliability objectives, and to estimate the cost of capacity that would be procured using such curves; and
- evaluated multiple alternative candidate curves.[32]

Brattle's review also took into account "three focus areas identified by PJM's Board and stakeholders:" (1) appropriate procurement levels; (2) uncertainty regarding Net CONE and reference technology; and (3) possible capacity market reforms resulting from PJM's Resource Adequacy Senior Task Force.[33]

In particular, the Brattle's evaluation of procurement levels shaped its review and proposed "candidate curve." Brattle examined and recommended a number of reforms to better procure appropriate levels of capacity. First, Brattle noted a number of changes already have been implemented or are being pursued that would tend to reduce procurement levels, including improving load forecast accuracy[34] and eliminating the 1% rightward shift adopted in 2014.[35] Brattle also identified certain measures that would facilitate procuring an appropriate level of capacity, including:

- change the Reference Resource from a combustion turbine ("CT") to a CC;

[31] 2022 VRR Curve Study at 1.

[32] *See* 2022 VRR Curve Study at 19-35.

[33] *See* 2022 VRR Curve Study at 1-2.

[34] PJM and its stakeholders are working in the Load Analysis Subcommittee to reduce forecast model error.

[35] The 1% rightward shift was eliminated as part of PJM's 2018 periodic review. *See PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029, at PP 27-28 (2019) ("2018 Review Order"), *reh'g denied*, 171 FERC ¶ 61,040 (2020), *aff'd in part*, *Del. Div. of the Pub. Advoc. v. FERC*, 453 U.S. App. D.C. 161, 3 F.4th 461 (2021).

- adopt a forward-looking EAS Offset methodology;
- adjust the VRR Curve shape "to mitigate potential for excess procurement in long capacity conditions (reduce the x-axis quantity at point 'C');" and
- improve capacity measurement and accounting practices for all purposes and seasonal reliability assessments.[36]

As discussed below, PJM proposes to adopt these recommendations, such that the VRR Curve will become steeper and based on the Net CONE of CC Reference Resource using a forward-looking EAS Offset. PJM is also adopting Brattle's recommendation to simplify and improve capacity and reliability accounting by switching to a Unforced Capacity ("UCAP")-based accounting system for determining the VRR Curve shape, such that the VRR Curve points are a function of the PJM Reliability Requirement, which is denominated in UCAP, and not the IRM, which is denominated in installed capacity ("ICAP").

3. Assessment of the Current VRR Curve and Proposed VRR Curve.

The PJM Tariff calls for a review of the VRR Curve shape "based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis."[37] PJM's independent consultants have consistently used market simulation methods to assess the probabilities that various alternative curve designs will meet applicable reliability requirements, including Monte Carlo analysis, as Brattle performed here.

The Monte Carlo method is a probabilistic analysis method "based on simulation by random variables and the construction of statistical estimators for the unknown quantities."[38] As applied to VRR Curve analysis, the "random variables" are inputs like supply, demand, capacity import limits, and administrative Net CONE estimates, and the statistically estimated "unknown quantities" are the probabilistic measurements of reliability and cost outcomes. The Monte Carlo method aids understanding of expected outcomes by running hundreds of simulations, each with its own distinct combination of input variables, and showing how often particular outcomes, e.g., indicators of reliability and costs, arose when viewing those simulations in the aggregate.

[36] 2022 VRR Curve Study at 4 Table 2. Brattle also recommended exploration of switching Energy Efficiency Resources from supply-side to demand-side. PJM and stakeholders are currently exploring a number of other changes to its capacity market design in the Resource Adequacy Senior Task Force.

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

[38] *Monte-Carlo Method*, The European Mathematical Society (June 6, 2020), https://www.encyclopediaofmath.org/index.php/Monte-Carlo_method.

Brattle's simulations assume that the average price across all draws will converge at a market-determined Net CONE.[39] This is consistent with the basic design premise of RPM often recognized by the Commission,[40] that the PJM energy, capacity, and ancillary service markets will provide sufficient revenue to support new entry. In other words, supply offers into the market will reflect the new entry project developer's assessment of net revenues it requires from the capacity market, in light of the cost of its project and the revenues expected from the PJM EAS markets. This assumption also is consistent with long-run equilibrium conditions in a restructured market that relies to a significant degree on merchant investment for resource adequacy.

In this manner, Brattle modeled the current VRR Curve. However, consistent with the desire to address procurement level concerns and to test the performance of the current curve against other curves, Brattle also modelled a number of alternative curves, including a "candidate curve," that "is a steeper kinked curve [i.e., downward-sloping] based on a gas CC reference technology with a reduced foot [i.e., point of intersection with the x-axis] compared to the current VRR Curve."[41] As explained in the following sections, PJM is proposing to adopt Brattle's candidate curve, and for ease of understanding, this letter will generally refer to it as the "Proposed VRR Curve."

4. PJM Is Changing the Reference Resource to a Combined Cycle as the Basis for the CONE Used in the VRR Curve.

The primary building block of the VRR Curve is the Reference Resource. The VRR Curve shape is set at various price and quantity points, where the price component is a function of the (gross or net) CONE of the Reference Resource. As such, it is appropriate to examine first which resource should be the Reference Resource. Here, as recommended by Brattle, PJM proposes to replace the current Tariff requirement that the Reference Resource be a natural gas-fired CT plant with a natural gas-fired CC generating station.

PJM considered many types of resources to become the Reference Resource. As part of its consideration, PJM relied on Brattle's analysis in the 2022 CONE Report, which included a screening analysis of nine different resource technologies applying the following criteria: feasibility to build; economic source of incremental capacity; and accurate estimation of the resource's Net CONE.[42] The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems ("BESS"), hybrid photovoltaic BESS, utility scale solar, onshore wind, energy efficiency and demand

[39] *See* 2022 VRR Curve Study at 42-44.

[40] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 54 (2013), *order on reh'g*, 153 FERC ¶ 61,066 (2015), *remanded sub nom. NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at PP 3, 75, 89, 97 (2011), *aff'd sub nom. N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 (3d Cir. 2014).

[41] 2022 VRR Curve Study at 14.

[42] 2022 CONE Report at 15-16.

response, uprates/conversions, and emerging technologies.[43] Table 1 below shows how each resource type fared.

Table 1: Reference Resource Screening Analysis

Technology	Feasible to Build for DY	Economic Source of Capacity	Accuracy of Net CONE Estimates	Screening Decision
Gas CC	Yes	Yes	High	Consider as leading candidate
Gas CT	Yes	Unclear (few built, higher Net CONE)	High	Consider for further analysis
Battery Storage	Yes	Unclear (not standalone cleared in RPM)	Medium (falling costs; AS-dependence; ELCC stability?)	Consider for further analysis
Hybrid PV-BESS	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Utility-Scale PV	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Wind	Yes	Unclear (is any entering as merchant?)	Low (REC-dependence; low ELCC, stability)	Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR
Energy Efficiency/ DR	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Uprates/ Conversions	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Emerging Technologies	No	None	Low	Eliminate: Infeasible to build

Following application of these criteria, Brattle developed a short list with CC, CT, and BESS as finalists for potential Reference Resources.[44] Ultimately, CCs best met the selection criteria because Brattle found them to be "the most economic" and that they are "being built by developers."[45] In contrast, Brattle found that CTs "continue not to be built,

[43] 2022 CONE Report at 16.

[44] 2022 CONE Report at 18. With respect to those resources that did not make the short list, Brattle concluded that hybrid solar BESS and utility-scale solar resources should be eliminated due to their higher Net CONE uncertainty. Wind was eliminated because its Net CONE was both much higher than other technologies and difficult to assess accurately due to its low effective load carrying capability rating that magnifies cost estimation errors. Energy efficiency, demand response, and uprates/conversions were eliminated because of highly non-uniform costs across measures and site, along with scalability challenges. *See id.* at 17-18.

[45] 2022 CONE Report at 18.

consistent with our estimate that their [regional transmission organization ("RTO")] Net CONE is about 20% higher than the CC."[46] As for BESS, Brattle found that it is unclear whether such would be an economic source of capacity as BESS had the highest Net CONE among all resource candidates.[47] As further discussed below, PJM agreed that adoption of CC as the Reference Resource was prudent for this quadrennial review.

In the 2022 CONE Report, Brattle examined several different CC resource configurations.[48] Consistent with Brattle's recommendation, PJM proposes a CC Reference Resource "configured with a double train 1x1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine with evaporative cooling, Selective Catalytic Reduction technology and carbon monoxide catalyst, with firm gas transportation, and a heat rate of 6.604 MMbtu/MWh (with duct-firing) and 6.369 MMbtu/MWh (without duct-firing)."[49] Selection of these characteristics (i.e., a 1x1 configuration (one gas combustion turbine, one steam turbine) and firm gas transportation for fuel supply) reflects a shift in the technical specifications for CC Plants from prior quadrennial reviews.[50] It also reflects a shift in CC plant development within PJM from 2x1 configurations to 1x1.[51]

As a threshold matter, PJM's Tariff is not prescriptive as to how PJM will choose the Reference Resource.[52] While PJM has utilized a CT plant as the Reference Resource since RPM was established in 2006,[53] the proposal to move to a CC plant is consistent with current generation development trends, offers flexibility in operational parameters, and produces Net CONE reflecting the most economic technology. As the Commission has previously recognized, in selecting an appropriate reference technology on which to base an estimate of CONE, it is important to consider whether "(1) the reference technology is able to contribute to resource adequacy; (2) project developers will likely build a resource using the reference technology; and (3) capacity, energy, reserve, and other ancillary market revenues of the reference technology can be estimated accurately."[54] Relying on these considerations, PJM determined that a CC plant with the above-described characteristics as the Reference Resource best supports the broader RPM objective of procuring enough capacity to meet resource adequacy goals.[55]

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[46] 2022 CONE Report at 18.

[47] 2022 CONE Report at 18.

[48] 2022 CONE Report at 22-26.

[49] Proposed Tariff, Definitions R-S (definition of Reference Resource).

[50] *See* 2022 CONE Report at 49-50.

[51] *See id* at 18.

[52] 2018 Review Order, 167 FERC ¶ 61,029, at P 58.

[53] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331.

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

[55] 2022 CONE Report at 18.

PJM's choice is well supported. First, the CC plant is the most economically viable reference technology considered, and produces the lowest estimated Net CONE.[56] By contrast, CT resources have not been recently built in the PJM Region, and their estimated RTO Net CONE is approximately 20% greater than the CC Plant.[57]

Second, project developers are likely to build CC plants according to the specifications provided for the Reference Resource. As noted previously, utilizing a 1x1 double-train single-shaft, air cooled system configuration reflects a shift in CC plant development within PJM. Additionally, double-train 1x1 CCs make up about 42% of capacity for 1x1 CCs that have been built, or are under construction, since 2018.[58] The cooling system is assumed to be a closed-loop circulating water system with a multiple-cell dry air-cooled condenser. Recent trends of CC plants under construction in PJM show a switch to air-cooled condensers, most likely because cooling towers have become more difficult to permit due to greater water consumption.[59]

Third, a CC plant's Net CONE can be estimated more accurately than other resource types. Accurate estimation requires certainty of plant designs and their costs and the ability to estimate EAS offset using market data. It also requires that a standardized resource be scalable and not subject to rapid cost increases as the best sites are exhausted. Finally, accurate estimation requires a high UCAP/ICAP ratio or effective load carrying capability.[60] Among all of the resources analyzed, the CC plant had the highest accuracy of Net CONE estimates.[61]

PJM's selection of the CC plant as the Reference Resource is also consistent with Brattle's recommendation in its 2022 CONE Report to select a CC resource.[62] Utilizing selection criteria consistent with Commission precedent, Brattle concluded that "CCs . . . are the most economic and being built by developers. . . . In addition, CC Net CONE can be estimated relatively accurately."[63] By contrast, Brattle concluded that it is unclear whether CT resources are an economic source of capacity, and such resources have higher forward EAS uncertainty because they are committed and dispatched day-of, rather than forward.[64]

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[56] 2022 CONE Report at 48.

[57] 2022 CONE Report at 18.

[58] 2022 CONE Report at 22.

[59] 2022 CONE Report at 23-24.

[60] 2022 CONE Report at 16.

[61] 2022 CONE Report at 18

[62] 2022 CONE Report at 18.

[63] 2022 CONE Report at 18.

[64] *See* 2022 CONE Report at 18.

Consistent with Brattle's recommendation, PJM proposes that the Reference Resource does not have duel fuel capability and instead ensure access to fuel supply through firm transportation costs. This approach is grounded on the fact that developers have moved away from developing duel fuel capable CCs. In fact, since 2018, only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel source.[65] Additionally, nearly all new gas-fired plants that entered the market since the Base Residual Auction associated with the 2016/2017 Delivery Year have obtained firm transportation service.[66] Based on these trends, it is reasonable to assume that the Reference Resource will also have firm gas transportation.

PJM has been conscious of the impact of switching Reference Resources repeatedly. In its last periodic review, PJM hesitated to switch from a CT to CC as the Reference Resource, as it was not, at that time, comfortable proposing a dramatic change in the RPM auction parameters by updating the Reference Resource.[67] The Commission has "agree[d], that shifting between a combined cycle and combustion turbine unit from year to year could prevent owners of combustion turbines from recovering their costs over time."[68] However, now is the time to make the switch to a CC Reference Resource. The record in this proceeding, including the substantial evidence and trends presented in 2026/2027 CONE Report supports changing to the CC as the Reference Resource. Any future change to the Reference Resource, would likewise be deliberate and based on substantial evidence.

Finally, selection of a CC resource as the Reference Resource is consistent with Commission precedent finding that ISO-NE's CC-based reference technology to be just and reasonable.[69] The Commission concluded that use of a CC unit as the reference technology was appropriate "because it is a technology that appears likely to be developed" and because "ISO-NE can develop cost and revenue estimates for this technology with confidence."[70] As discussed above, PJM's analysis has determined that CC Plants are likely to be developed in the PJM Region and produce the most accurate Net CONE estimates. The Commission should therefore accept PJM's proposal to use the CC Plant as the Reference Resource as just and reasonable.

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[65] 2022 CONE Report at 26.

[66] *Id*.

[67] *See PJM Interconnection, L.L.C.*, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER19-105-000, at 11 & Attachment C (Affidavit of Adam J. Keech) ¶ 7 (Oct. 12, 2018) ("PJM is not comfortable proposing a dramatic change in the RPM auction parameters on an assumption that CT Plants no longer have a significant role to play in the PJM Region.").

[68] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 39 (2009) ("March 2009 RPM Order").

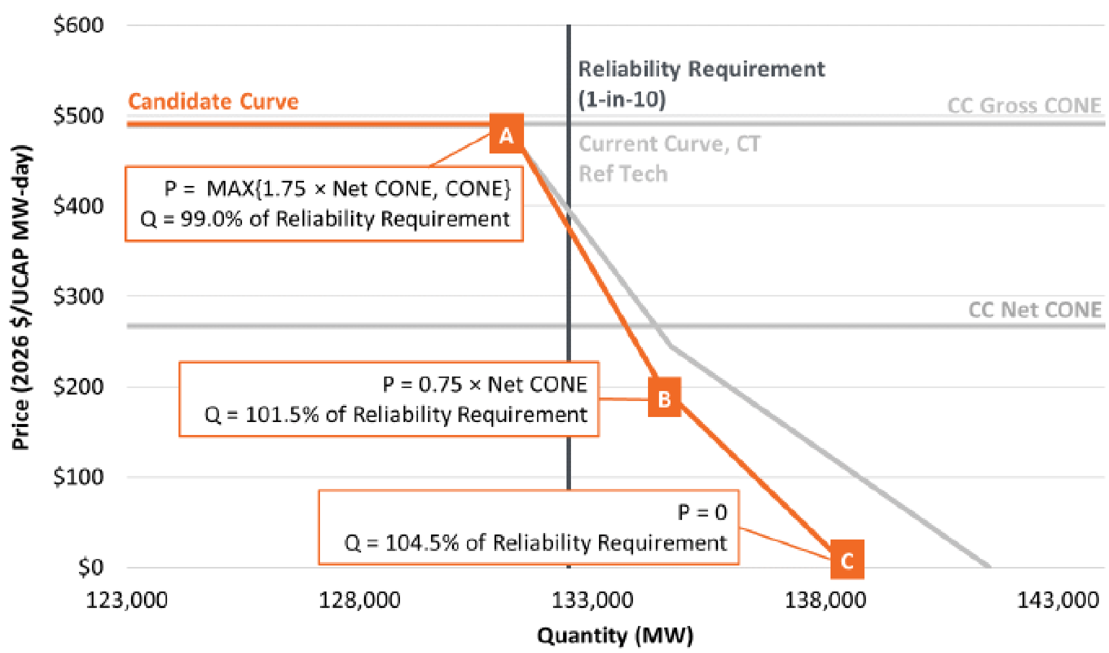
[69] *ISO New England*, 147 FERC ¶ 61,173, at P 32.

[70] *ISO New England*, 147 FERC ¶ 61,173, at P 32.

5. Adjusting the VRR Curve Shape.

Brattle's simulations found that merely changing the Reference Resource to a CC alone, without any other changes to the VRR Curve, would result in a "slightly steeper" curve and thus reduced capacity procurement.[71] However, "since the foot position would still be in the same wide position, changing the reference technology alone would not fully mitigate the potential for over-procurement."[72] Therefore, to address concerns about the level of capacity procurement beyond the Reliability Requirement, PJM is adopting Brattle's recommended "candidate" curve and proposing four changes to the determination of the VRR Curve shape detailed below.[73] Figure 2 shows the current VRR Curve and the Proposed VRR Curve.

Figure 2: Proposed and Current VRR Curves



Brattle arrived at this curve, "through an iterative approach involving input from stakeholders, qualitative analysis, and probabilistic simulations under base case and stress conditions."[74] As discussed below, Brattle evaluated several alternative curve shapes, finding each offered a different balance of trade-offs. Specifically, flatter curves offer

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[71] 2022 VRR Curve Study at 20.

[72] 2022 VRR Curve Study at 20.

[73] *See* 2022 VRR Curve Study at 20 ("[T]o further address the potential for over-procurement, our recommended Candidate Curve has a reduced foot and is a slight departure from the Current Curve, CC Ref Tech.").

[74] VRR Curve Aff. ¶ 6.

improved price stability, but at the cost of greater quantity uncertainty while steeper curves "offer improved certainty in quantity, but at the cost of higher price volatility."[75] Overall, Brattle found the Proposed VRR Curve "offer[s] a substantial improvement over the current curve with respect to the potential for over-procurement, commensurately reducing expected customer costs, while maintaining reliability in excess of the reliability standard and while producing a modest expected increase in price volatility."[76]

It is important to keep in mind that none of the individual changes to PJM's Proposed VRR Curve should be viewed in isolation. Rather, the changes work together to establish a VRR Curve that ensures continued reliability, while addressing procurement level concerns and maintaining a reasonable cost to load. In short, PJM's Proposed VRR Curve is just and reasonable, as explained below and demonstrated by Brattle's simulations and studies.

a. PJM proposes to update VRR Curve Shape formula to use the UCAP-denominated Reliability Requirement.

The first change is not directly related to the shape, but to the metric used to determine the shape. Currently, the VRR Curve is determined based on the Reliability Requirement, which is denominated as Unforced Capacity, or UCAP. However, the points on the VRR Curve are derived by multiplying the Reliability Requirement by a ratio that is determined using the IRM, which is denominated in installed capacity, or ICAP. To simplify and provide stability, PJM is proposing to set percentages that are applied directly against the Reliability Requirement rather than against the IRM in setting the ratio. This change simplifies the determination of the VRR Curve by "remov[ing] the need for a unit conversion that is embedded within the formulas of the current VRR Curve."[77] In other words, the revised formula for each x-axis point of the VRR Curve more concisely defines the Reliability Requirement percentage as a direct percentage as opposed to a formula, based on IRM, that yields the same Reliability Requirement percentage. Replacing the IRM-based formula with the Reliability Requirement is reasonable, as both metrics represent the "target level of reserves required" to meet reliability standards, but are expressed in different capacity values.[78]

b. While retaining the "price cap" formulation of the greater of gross CONE and a multiple of Net CONE, PJM proposes to increase the Net CONE multiplier.

Currently, the first leg of the VRR Curve starts on the y-axis at the point equal to the greater of gross CONE or 1.5 times Net CONE and extends horizontally to the point

[75] VRR Curve Aff. ¶ 16.

[76] VRR Curve Aff. ¶ 22.

[77] VRR Curve Aff. ¶ 18.

[78] *PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., 28 (Sept. 21, 2022), https://www.pjm.com/-/media/documents/manuals/m18.ashx.

where the amount of capacity cleared would equal IRM minus 1% (which generally equates to 99% of the Reliability Requirement).[79] This is illustrated as "Point A" in Figure 2 above. This price cap is the maximum price the market is willing to pay for capacity. The end point of this leg is set at IRM minus 1%, which "represents the [capacity procurement] threshold below which PJM would consider corrective actions to ensure sufficient system capacity."[80]

As recommended by Brattle, PJM proposes to modify the formula for determining this price cap to the greater of gross CONE or 1.75 times Net CONE (noting that gross CONE may still set the price cap if it is greater than the multiple of Net CONE). The need to increase the Net CONE multiplier for setting the price cap from 1.5 times Net CONE to 1.75 times Net CONE arises from the higher uncertainty in the Net CONE estimate and rapid turnover in the capacity fleet caused by environmental policies, technological changes, and the retirement of aging plants.[81] Additional factors contributing to these Net CONE uncertainties include large uncertainties in expected gas market prices (and consequently, in electricity prices and EAS offsets); ongoing uncertainties and instabilities in commodity markets, labor markets, supply chains, and financial across many sectors which have introduced challenges in estimating an accurate CONE estimate;[82] along with the effects of state and federal policies on the design of the Reference Resource and fleet turnover, including indirect effects on the EAS offset.[83]

More specifically, as Brattle explains "[w]orld natural gas shortages caused by Russia's invasion in February 2022 are elevating and destabilizing gas and power prices more than any time since 2008."[84] For example, PJM's forward-looking estimate of EAS offsets for a CC resource has increased just over the course of this study (i.e., from July 2021 through April 2022) by $84/MW-day (UCAP), which "reduces Net CONE by about 24%."[85] In the VRR Curve Affidavit, Brattle states that "[i]f such shifts occurred again between the time when PJM sets auction parameters and the auction, the administrative value of Net CONE could differ sharply from capacity suppliers' expectations at the time

[79] *See* Tariff, Attachment DD, section 5.10(a)(i) ("For the 2022/2023 Delivery Year and subsequent Delivery Years, . . . For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 1.2%) divided by (100% plus IRM%)]").

[80] 2022 VRR Curve Study at 22. If PJM procures less than IRM minus 1% for three years in a row, a Reliability Backstop Auction would be triggered. Tariff, Attachment DD, section 16.3(a)(i).

[81] *See* VRR Curve Aff. ¶ 19.

[82] *See* VRR Curve Aff. ¶ 12.

[83] VRR Curve Aff. ¶ 19.

[84] *See* VRR Curve Aff. ¶ 11.

[85] VRR Curve Aff. ¶ 11.

of the auction."[86] Further, market conditions could change between the relevant RPM Auction and the Delivery Year, and the prospect of such changes may be difficult for PJM to estimate. Thus, PJM risks under-estimating Net CONE, and setting the cap at a higher multiple of Net CONE mitigates the risk of under-procuring.

As noted by Brattle, CONE itself is also particularly volatile currently due to supply chain shortages and associated inflation that is higher and more volatile than any time in the past 40 years.[87] In fact, the consumer price index forecast for 2026 has increased by about 20% since Brattle began its VRR Curve review study in July 2021 and continues to change rapidly. With that and related changes in the cost of capital, Brattle's estimate of CONE increased by 8% just since Brattle's report was completed in April, 2022, which increases Net CONE by roughly twice that percentage.[88]

Meanwhile, the pace of the industry's transition to clean energy is much greater than in any prior quadrennial review, with many effects on Net CONE and its uncertainty—primarily the long-term, which affects investors' current choice of technology and their views of the long-term net energy and capacity revenues they will earn, and thus how much capacity revenue they would need in year one in order to be willing to enter the market (i.e., the "economic life" and levelization approach).[89] In particular, policies in several states propose or mandate the sharp reduction or eventual elimination of fossil generation (i.e., New Jersey and Illinois). Other states are less oriented toward clean energy mandates, but they too are affected by the rapid cost declines (until recently) of wind, solar, and storage, and federal policies supporting them. For example, the recent Inflation Reduction Act[90] provides up to 50% tax credits for standalone storage and extended and expanded tax credits for solar and wind. Brattle found that "[w]ith all of these changes, the composition of the fleet and market/regulatory conditions in 10-20 years will be very different from today."[91] The value of existing resources, including current entrants, will be highly impacted in ways that are difficult to predict accurately.

Based on the foregoing, it has become much more difficult to accurately estimate a Reference Resource's long-term revenue projections that are essential for developing a reservation price for entry (i.e., "Net CONE"). Therefore, it is prudent to guard against these uncertainties. Consequently, PJM is adopting Brattle's recommendation to increase the price cap to 1.75 times Net CONE, which will "provide greater protection against low-reliability outcomes in years under different market conditions where energy and ancillary services offsets decrease and the 1.75 × Net CONE cap is binding."[92] This protection

[86] VRR Curve Aff. ¶ 11.

[87] VRR Curve Aff. ¶ 12.

[88] VRR Curve Aff. ¶ 12.

[89] VRR Curve Aff. ¶ 13.

[90] *See* Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818.

[91] VRR Curve Aff. ¶ 13.

[92] VRR Curve Aff. ¶ 24.

against low reliability events most relevant if the administrative Net CONE parameter is under-estimated relative to the true Net CONE faced by developers.

As can be seen in Figure 2 above, practically speaking this does not change the price cap much from the current VRR Curve to the Proposed VRR Curve. Under current estimations of gross and Net CONE for the CC Reference Resource, if the multiplier were maintained at 1.5 times Net CONE, the price cap would remain largely the same, as gross CONE would set the value. Stated another way, the increase in the Net CONE multiplier for setting the price cap is unlikely to materially affect the VRR Curve given that gross CONE exceeds both 1.5x and 1.75x Net CONE under Brattle's estimates.[93] Nonetheless, Brattle concluded that the higher multiplier "may provide some incremental protection against the possibility of too-low pricing during short supply conditions."[94]

In addition, changing the Net CONE multiplier has a smaller effect when the Reference Resource is a CC because the greater EAS revenues associated with a CC than a CT mean that Net CONE is a lower percentage of gross CONE. Thus, the relationship between gross CONE and 1.75 times Net CONE for a CC Reference Resource is similar to the relationship between gross CONE and 1.5 Net CONE for the CT Reference Resource.

Further, one of the overriding considerations in this periodic review is to address procurement level concerns, both variability and quantity. Increasing the multiplier could help fulfill this objective, as "a higher price cap allows for a steeper curve"[95] and a steeper curve reduces variability in capacity procurement levels, especially when Net CONE is estimated with error.[96] Consider the following example from the 2022 VRR Curve Study. If the Net CONE used to shape the VRR Curve (i.e., "administrative Net CONE") was understated, and the actual ("true") Net CONE facing developers was 1.4 times administrative Net CONE, there would be an "insufficient small 'buffer' of only 0.1 × Net CONE between the price cap and the long-run average price needed to attract entry," and "[t]he only way to produce average prices near the long-run cost of supply would be to clear at the price cap (*i.e.*, in shortfall) approximately half of the time."[97] However, such an outcome would be unsustainable, as it would often necessitate administrative intervention, whether through Reliability Backstop Auctions or other means.

To further provide analytical evidence in support of raising the price cap, Brattle also performed Monte Carlo simulations of the Proposed VRR Curve with the price cap at (1) gross CONE, (2) Net CONE times 1.75, and (3) Net CONE times 1.5, and with sensitivities assuming the true Net CONE facing the developers is the CC Reference

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[93] VRR Curve Aff. ¶ 23.

[94] 2022 VRR Curve Study at 16.

[95] 2022 VRR Curve Study at 23.

[96] 2022 VRR Curve Study at 16.

[97] 2022 VRR Curve Study at 16 n.19.

Resource's Net CONE, that value +/- 40%, and the Net CONE of the CT resource evaluated in the 2022 CONE Report. The results are shown in Table 2 below, and in the VRR Curve Affidavit.

Table 2: Performance of the Proposed VRR Curve (Price cap at either 1 × CONE or 1.75 × Net CONE) compared to an Alternative Curve (Price cap at 1.5 × Net CONE)

	Price			Reliability					Cost
	Average ($/MW-d)	Standard Deviation ($/MW-d)	Frequency at Cap (%)	Average LOLE (events/yr,	Average Excess (Deficit) (MW)	Average Excess (Deficit) (IRM + X %)	Frequency Below Target (%)	Frequency Below IRM - 1% (%)	Average Procurement Cost ($ mln/yr)
Proposed Curve, Cap at 1 × Gross CONE									
True Net CONE = 0.6 × CC	$160	$57	0.0%	0.043	2861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 × CC	$374	$94	21.2%	0.128	(393)	(0.3%)	50.0%	24.8%	$18,092
Proposed Curve, Cap at 1.75 × Net CONE									
True Net CONE = 0.6 × CC	$160	$57	0.0%	0.043	2851	2.5%	0.0%	0.0%	$7,938
True Net CONE = CC	**$267**	**$81**	**3.3%**	**0.076**	**1137**	**1.0%**	**13.6%**	**3.9%**	**$13,092**
True Net CONE = CT	$326	$88	11.6%	0.103	224	0.2%	36.3%	12.4%	$15,863
True Net CONE = 1.4 × CC	$374	$85	27.0%	0.141	(677)	(0.5%)	57.2%	30.4%	$18,045
Alternative Curve, Cap at 1.5 × Net CONE									
True Net CONE = 0.6 × CC	$160	$56	0.0%	0.044	2812	2.4%	0.0%	0.0%	$7,935
True Net CONE = CC	**$267**	**$69**	**7.2%**	**0.087**	**753**	**0.7%**	**24.0%**	**7.9%**	**$13,041**
True Net CONE = CT	$326	$67	26.9%	0.139	(604)	(0.5%)	55.3%	29.0%	$15,741
True Net CONE = 1.4 × CC	$374	$46	59.0%	0.251	(2498)	(2.1%)	85.3%	61.3%	$17,761

Notes: All quantities in 2026$/UCAP MW-day. Parameters: Gross CONE = $491, Net CONE = $267, 1.5 × Net CONE = $401, 1.75 × Net CONE = $467. The formulas for points A, B, and C on the proposed and alternative curves are identical, except for the price at Point A.

The price cap has no impact on average or equilibrium price outcomes, with the average clearing price being $267/MW-Day—the same under all three price caps when true Net CONE equals the value Brattle estimated for the CC Reference Resource. Though there are differences in average procurement quantity and average excess, the impact on average procurement cost is small (0.4% higher costs under a 1.75× Net CONE cap compared to a 1.5× cap). However, setting the price cap at 1.5 times Net CONE appears to have a significant impact on how often the market would clear insufficient amounts of capacity to maintain reliability (i.e., at the price cap). This is true both when Net CONE is accurately estimated and when it is estimated with error. When accurately estimated, the 1.5 × Net CONE cap nearly doubles the frequency of clearing under the target reserve margin (24.0% vs 13.6%) and the frequency of clearing below IRM – 1% (7.9% vs 3.9%).

When Net CONE is estimated with error, the reliability implications can be even more substantial. Specifically, in a sensitivity scenario in which the true Net CONE (consistent with a gas CT plant) is higher than administrative Net CONE, the proposed VRR Curve with cap at 1.75 × Net CONE will produce reliability at approximately 0.103 LOLE, or very near PJM's 1-in-10 reliability standard. Under the same scenario, an alternative curve with a lower price cap at 1.5 × Net CONE would produce poorer reliability at approximately 0.139 LOLE (1-in-7.2).[98] In a scenario with a larger under-estimate of Net CONE (true Net CONE 40% higher than administrative Net CONE), the higher price cap offers greater reliability protections. The proposed curve with a cap at 1.75 × Net CONE maintains reliability at 0.141 LOLE (1-in-7.2) while the lower cap at 1.5 × Net CONE would produce severely degraded reliability at 0.251 LOLE (1-in-4).[99]

Thus, if administrative Net Cone is underestimated, the PJM Region would just barely meet the 1-in-10 LOLE target under the Proposed VRR Curve (i.e., greater of gross CONE or 1.75 times Net CONE), but clearly fail to meet the 1-in-10 LOLE target with a price cap set at 1.5 times Net CONE, and the frequency of being in a capacity shortage (i.e., at the price cap) skyrockets. Thus, Brattle concluded that "[m]aintaining a high contingent price cap protects against low reliability events by ensuring that prices can become high enough to attract sufficient supplier interest to develop needed capacity supplies and produce prices at the true Net CONE on average, even if administrative Net CONE is underestimated."[100]

In short, the 1.75 Net CONE multiplier acts as protection against Net CONE uncertainties. Such protection is important given the "substantial uncertainties in Net CONE under current and anticipated market conditions."[101] The 2022 CONE Report explains that "[m]ost of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery."[102] While, the change in the Net CONE multiplier used in setting the price cap "is not likely to affect the VRR Curve performance under expected market conditions,"[103] in the event Net CONE is underestimated, it "will substantially improve reliability under a potential scenario where Net CONE is under-estimated and the Net-CONE-based cap is binding."[104]

c. While PJM does not propose a substantive change to the "kink" point in the curve, the change to a CC Reference Resource would tend to lower the point.

The second leg of the curve extends downward from Point A to a point, labeled in Figure 2 as "Point B," at which the amount of capacity cleared would equal IRM plus 1.9%

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[98] VRR Curve Aff. ¶ 24.

[99] *Id.*

[100] VRR Curve Aff. ¶ 27. *See also* 2022 VRR Curve Study at 24 ("[H]igher price cap is also more robust to Net CONE estimation uncertainty whereas a lower price cap is more susceptible, which could cause reliability concerns if the market clears too far below the Reliability Requirement.").

[101] VRR Curve Aff. ¶ 27.

[102] 2022 CONE Report at 57.

[103] VRR Curve Aff. ¶ 28.

[104] VRR Curve Aff. ¶ 28.

at a price equal to 75% of Net CONE.[105] PJM generally does not propose to change this basic formula for determining this point, except to redefine the amount of capacity procured from IRM plus 1.9% to 101.5% of the Reliability Requirement. Changing to the Reliability Requirement is estimated to shift Point B to the left by approximately 0.1% of the Reliability Requirement.[106] Figure 2 above shows Point B as lower on the Proposed VRR Curve than the current VRR Curve, and that is due to the change to a CC Reference Resource and the lower associated Net CONE than would be for a CT Reference Resource. Note too that by keeping the price cap and Point A the same, but decreasing the price applicable for Point B, the resulting curve is steeper.

d. PJM proposes to shift the foot of the curve substantially to the left to address procurement concerns.

From Point B, the third leg of the curve extends, convexly relative to the second leg, to the x-axis, i.e., the "foot" of the curve. Currently, the foot is set at the point where the amount of capacity that would clear equals IRM plus 7.8%.[107] Consistent with Brattle's recommendation, PJM proposes to set the foot at 104.5% of the Reliability Requirement. Brattle determined that this is an approximately 2.2% of the Reliability Requirement leftward shift.[108] Figure 2 illustrates this significant leftward shift of the foot.

This shift will help prevent costly impacts of overestimations of Net CONE, which would result in more reliability than expected. Shifting the foot to the left further steepens the curve, and meaningfully reduces the amount of capacity that would be procured along this leg of the curve, i.e., at prices less 0.75 times Net CONE. This also reduces the impact of potential overestimation of Net CONE. Further Brattle recommends the proposed foot, and resulting steeper curve, "based on several observations:"

- under recent market conditions, the RPM has experienced a sustained long-market condition and a large turnover of the resource mix;
- prices even in the "foot" region of the prior VRR curves have been high enough to retain existing supply and attract new supply;
- under these market conditions a relatively steep demand curve can more effectively "right-size" capacity procurements without introducing large problems with price volatility; and

[105] *See* Tariff, Attachment DD, section 5.10(a)(i) ("For the 2022/2023 Delivery Year and subsequent Delivery Years, . . . For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1.9%) divided by (100% plus IRM%)])").

[106] VRR Curve Aff. ¶ 19.

[107] *See* Tariff, Attachment DD, section 5.10(a)(i) ("For the 2022/2023 Delivery Year and subsequent Delivery Years, . . . For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 7.8%) divided by (100% plus IRM%)]").

[108] VRR Curve Aff. ¶ 19.

- a flatter curve is more susceptible to exacerbating current surpluses.[109]

Brattle's "simulation results confirm[ed] these same observations."[110]

e. PJM's Proposed VRR Curve is just and reasonable.

Taken together the foregoing changes to the VRR Curve shape would yield a VRR Curve that is expected to reduce the quantity of capacity that clears each auction (while supplies remain long), which would tend to lower average procurement costs to load. Brattle "examine[d] the likely performance of the Candidate Curve compared to the Current Curve, and other alternative VRR Curves," by "conduct[ing] a probabilistic simulation analysis of potential market outcomes under long-run equilibrium conditions."[111] Table 3 provides the results of Brattle's simulations for both the current VRR Curve and the Proposed VRR Curve (listed in the table as Brattle's "candidate" curve).

Table 3:
Performance of the Current vs. Proposed VRR Curve Under Base Scenario (Accurate Net CONE) and Uncertainty Scenarios (Net CONE Over- or Under-Estimate)

	Price			Reliability					Cost
	Average ($/MW-d)	Standard Deviation ($/MW-d)	Frequency at Cap (%)	Average LOLE (events/yr)	Average Excess (Deficit) (MW)	Average Excess (Deficit) (IRM + X %)	Frequency Below Target (%)	Frequency Below IRM - 1% (%)	Average Procurement Cost ($ mln/yr)
Current Curve									
True Net CONE = 0.6 × CC	$160	$52	0.0%	0.026	4548	4.0%	0.0%	0.0%	$8,029
True Net CONE = CC	**$267**	**$74**	**1.5%**	**0.059**	**2026**	**1.8%**	**7.5%**	**2.0%**	**$13,169**
True Net CONE = CT	$326	$86	7.8%	0.085	922	0.8%	23.2%	9.0%	$15,941
True Net CONE = 1.4 × CC	$374	$87	17.9%	0.117	(25)	0.0%	43.2%	20.0%	$18,133
Proposed Curve									
True Net CONE = 0.6 × CC	$160	$57	0.0%	0.043	2861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 × CC	$374	$94	21.2%	0.128	(393)	(0.3%)	50.0%	24.8%	$18,092

Table 3 shows that Brattle's simulations found the current VRR Curve achieves the reliability goals for which it was designed, with an average LOLE of 0.059, which equates to a loss of load event of about 1-in-17, significantly greater reliability than the target 0.1 LOLE of 1-in-10 years. The Proposed VRR Curve, i.e., the "candidate" curve, also

[109] 2022 VRR Curve Study at 16.

[110] 2022 VRR Curve Study at 16.

[111] 2022 VRR Curve Study at 17.

achieves the reliability goals with an average LOLE of 0.073, which equates to a loss of load event of about 1-in-14, is also greater than the target 0.1 LOLE of 1-in-10 years. Brattle explains that lower reliability of the Proposed VRR Curve is due to "reduce[d] procurement volumes"[112] relative to the current VRR Curve. Indeed, Brattle found that under "the Current Curve, CT would over-procure by a greater volume and with a slightly greater frequency than the Candidate Curve."[113]

Also, the amount of capacity procured under the current VRR Curve varied more greatly than that would be procured under the Proposed VRR Curve, which is logical given that the Proposed VRR Curve is steeper. Further, Brattle's simulations showed that the proposed curve "reduces expected procurement beyond the Reliability Requirement by 805 UCAP MW on average compared to the Current Curve, CT under . . . base assumptions."[114] That average reduction in procurement is a feature of the Proposed VRR Curve. By steepening the curve between Point B and Point C, "the proposed VRR Curve will reduce the capacity market's susceptibility to over-procurement, particularly in long market conditions."[115]

In contrast, the clearing price varied more greatly under the Proposed VRR Curve than under the current VRR Curve, which again is a function of the Proposed VRR Curve's steeper slope. However, Brattle's simulations showed that "increase in price volatility for the [Proposed VRR] Curve is modest, on the order of $11/UCAP MW-day."[116]

Regardless of the increased price volatility, Brattle's simulations indicate that the Proposed VRR Curve should, on average, yield lower overall cost to load. That is, as shown in Table 3, the total annual customer costs were slightly higher for the current VRR Curve at $13.169 billion per year than for the Proposed VRR Curve at $13.104 billion per year.

The tradeoff of price volatility and procurement quantity volatility is central to choosing the Proposed VRR Curve. An objective in this review is to ensure that the curve achieves "appropriate levels of procurement."[117] Brattle's simulations demonstrate that the VRR Curve can be adjusted to do this "by adopting a lower and more accurate estimate of Net CONE and adjusting the shape of the curve to limit the potential for over-procurement in capacity long conditions."[118]

[112] 2022 VRR Curve Study at 17.

[113] 2022 VRR Curve Study at 18.

[114] 2022 VRR Curve Study at 18.

[115] VRR Curve Aff. ¶ 20.

[116] 2022 VRR Curve Study at 18.

[117] 2022 VRR Curve Study at 3.

[118] 2022 VRR Curve Study at 3.

In addition to evaluating the current and Proposed VRR Curves, Brattle evaluated the current curve, but based on a CC Reference Resource,[119] and "based on parameters that were 'tuned' to achieve a 1-in-10 LOLE on average."[120] Brattle "assess[ed] that the potential for over-procurement under long-capacity conditions can be reduced by reducing the quantity point at point 'C' [i.e., the foot] in the demand curve without materially sacrificing overall VRR Curve performance."[121] Brattle found the Proposed VRR Curve to be "approximately in the middle of the range of tested curves in terms of key performance trade-offs, specifically, the clearing price volatility and expected excess procurement."[122]

Finally, Brattle's evaluation of the current CT-based VRR Curve and the CC-based Proposed VRR Curve also shows the significant reductions in costs that will be borne by load by both the shift to a CC Reference Resource and steepening the curve. As shown in the Table 3 above, analysis shows that the average procurement cost under the current curve with a CT Reference Resource would be $15,951,000 per year compared to the proposed curve with a CC Reference Resource at $13,104,000 per year (a nearly 18% reduction in cost). The cost savings can be primarily attributed to adopting the CC as the Reference Resource, given its much lower Net CONE relative to a CT resource.[123]

Ultimately, "both curves produce price and quantity outcomes that are generally 'workable', and without substantial concerns," but the Proposed VRR Curve "offer[s] improved performance compared to the Current Curve given that it reduces total procurement levels and associated costs, while still exceeding the 1-in-10 standard and offering otherwise similar performance."[124]

6. Implementing Tariff Changes.

To reflect the proposed VRR Curve in the Tariff, PJM is revising Tariff, Attachment DD, section 5.10(a)(i) to state the revised price and quantity parameters that describe each of the three line segments that will comprise the VRR Curve used in RPM Auctions, beginning with the 2026/2027 Delivery Year.[125]

PJM also proposes to revise the definition of Reference Resource to reflect the use of a CC resource as shown in blackline below:

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[119] *See* 2022 VRR Curve Study at 20-21, Figure 7 & Table 5.

[120] 2022 VRR Curve Study at 22.

[121] 2022 VRR Curve Study at 10.

[122] 2022 VRR Curve Study at 18.

[123] *See* Brattle/S&L CONE Aff.

[124] 2022 VRR Curve Study at 18.

[125] PJM maintains the VRR Curves described in the current Tariff for earlier Delivery Years, inasmuch as PJM will still conduct auctions for some of those years.

> For Delivery Years up to and including the 2025/2026 Delivery Year, "Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh. For the 2026/2027 Delivery Year and subsequent Delivery Years, "Reference Resource" shall mean a combined cycle generating station, configured with a double train 1x1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine with evaporative cooling, Selective Catalytic Reduction technology and carbon monoxide catalyst, with firm gas transportation, and a heat rate of 6.604 MMbtu/MWh (with duct firing) and 6.369 MMbtu/MWh (without duct firing).[126]

This definition codifies the characteristics of the CC Reference Resource discussed above beginning with the RPM Auctions associated with the 2026/2027 Delivery Year. It is necessary to retain the existing definition of a CT Reference Resource to ensure that there is no confusion as to what the Reference Resource is for RPM Auctions prior to the 2026/2027 Delivery Year.

C. Updates to the Gross Cost of New Entry Values.

1. Background.

The CONE is an estimate of the total project capital cost and annual fixed operations and maintenance ("O&M") expenses of a new generating plant of a type likely to provide incremental capacity to the PJM Region in the forward Delivery Year addressed by the RPM auctions. The Tariff currently defines that representative new entry plant, or "Reference Resource," as a CT power plant.[127]

From 2006 when RPM was first adopted until the present, CONE values in the Tariff have consistently been based on detailed, "bottom-up" estimates of the components of a representative new entry project.[128] Thus, capital costs include, for example, the turbine power package and other major materials, land, station equipment, buildings, necessary gas pipeline and electric transmission infrastructure, emissions control equipment, permitting costs, and any contingency. The ongoing fixed O&M expenses include, for example, labor, outside contractor costs for operations or maintenance, property taxes, insurance, overheads, and regulatory expenses. The CONE in each case was developed using a financial model that includes estimates of the likely debt cost,

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[126] Proposed Tariff, Definitions R-S (definition of Reference Resource).

[127] Tariff, Definitions-R-S (definition of Reference Resource).

[128] *See, e.g.*, March 2009 RPM Order, 126 FERC ¶ 61,275, at P 36 ("PJM provided a detailed engineering study to support the CONE values contained in [its original] filing [and] [t]hat study also shows that the CONE values [ultimately proposed by PJM] are just and reasonable").

required internal rate of return, income taxes, and the project's economic life. Each CONE estimate in the prior reviews has been provided by independent expert consultants with relevant expertise.

The Tariff contains separate CONE estimates for each of four "CONE Areas" that are defined in terms of the transmission owner zones they encompass, as follows:

- CONE Area 1: Eastern MAAC (PS, JCP&L, AE, PECO, DPL, RECO);
- CONE Area 2: Southwestern MAAC (PEPCo, BG&E);
- CONE Area 3: Rest-of-RTO (AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC); and
- CONE Area 4: Western MAAC (PPL, MetEd, Penelec).[129]

The Tariff also includes a mechanism for automatic updates to the CONE values based on changes in the Applicable United States BLS Composite Index, a utility construction cost index.[130] This mechanism is intended to keep the CONE values up to date with the latest trends in electric plant construction costs in the years between PJM's quadrennial reviews.[131]

For this quadrennial review, PJM followed the same "bottom-up" approach that yielded CONE values previously accepted by the Commission as just and reasonable.[132] In addition to the 2022 VRR Curve Report, Brattle prepared a detailed estimate of the CONE for use in the VRR Curve. The results of Brattle's review and analysis are set forth in its 2022 CONE Report. A copy of that report is attached to the Brattle/S&L CONE Affidavit. As explained in their affidavit, Dr. Newell led the Brattle review of the CONE parameters together with Mr. Gang and his team at S&L. PJM also attaches the affidavit of Brattle's Mr. Pfeifenberger and Dr. Zhou, who describe and support the after-tax weighted average cost of capital ("ATWACC") that is used in the determination of Gross CONE.[133]

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[129] Proposed Tariff, Attachment DD, section 5.10(a)(iv)(B).

[130] Tariff, Attachment DD, section 5.10(a)(iv)(B) ("[T]he CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ('BLS') Composite Index").

[131] *See PJM Interconnection, L.L.C.*, 129 FERC¶ 61,090, at P 38 (2009).

[132] *See* March 2009 RPM Order, 126 FERC ¶ 61,275, at P 36; *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,079, at P 70 (2013) (accepting settlement of CONE values that were supported by PJM's initial detailed CONE estimates and certain cost adjustments from the "detailed alternative estimates" provided by other parties in the case); *ISO New England*, 147 FERC ¶ 61,173, at PP 17, 29-35 (accepting stated CONE values for the ISO-NE forward capacity auction based on detailed "bottom up" CONE Report conducted by Brattle and S&L).

[133] Attachment F, Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C. ("ATWACC Aff.").

2. Proposed Gross CONE Values.

As a result of the detailed, bottom-up analysis conducted in this quadrennial review,[134] PJM proposes the following values for the Gross CONE in the four CONE areas:

CONE Area 1: $198,200/MW-year
CONE Area 2: $193,100/MW-year
CONE Area 3: $197,800/MW-year
CONE Area 4: $199,700/MW-year[135]

PJM is incorporating these proposed values, which are fully supported in the 2022 CONE Report and the affidavits accompanying this transmittal, in Tariff, Attachment DD, section 5.10(a)(iv)(C). These values reflect a 20-year economic life, an assumption that PJM has utilized since the inception of RPM, and that Brattle recommended.[136]

3. After-Tax Weighted Average Cost of Capital.

The ATWACC is used as a discount rate to annualize new entry investment costs. It is a necessary component of Gross CONE, and helps set the Gross CONE level, but it does not set, prescribe, limit, or define the investment return that any seller in PJM's capacity market will earn. Brattle conducted a detailed financial review and analysis to help PJM set the level of ATWACC and its components.[137] In that respect, Brattle followed essentially the same approach used for the last CONE review, which the Commission found to be just and reasonable.[138]

As Mr. Pfeifenberger and Dr. Zhou explain in their affidavit, consistent with their analyses in previous PJM CONE reports, Brattle examined (1) a sample of U.S. independent power producers; and (2) ATWACC-based discount rates used by financial analysts in evaluating recent merchant generation merger and acquisition transactions.[139] In the 2022 CONE Report, Brattle estimated the ATWACC for the new entry plant would be 8.0%.[140] In August 2022, Brattle increased its ATWACC estimate due to the effects of short term interest rate increases by the Federal Reserve between March 31 and August 31,

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[134] The values shown here exceed those presented in the 2022 CONE Study by about 8.2% because of two updates that were necessary given recent changes in economic conditions: first, the estimated ATWACC has increased from 8% the time of the 2022 CONE Study to 8.85% today. Second, inflation has increased beyond that assumed in the 2022 CONE Study. Brattle/S&L CONE Aff. ¶ 19.

[135] Tariff, Attachment DD, section 5.10(a)(iv)(B).

[136] *See* 2022 CONE Report at 47.

[137] ATWACC Aff. ¶ 6.

[138] 2018 Review Order, 167 FERC ¶ 61,029, at P 101.

[139] ATWACC Aff. ¶ 7.

[140] ATWACC Aff. ¶ 6.

2022.[141] As shown by Mr. Pfeifenberger and Dr. Zhou, Brattle's August 2022 ATWACC estimate was 8.85%, including debt and equity ratios of 55% and 45%, respectively, a cost of BB-rated debt of 4.7%, and a cost of equity of 13.6%.[142]

The Gross CONE values set forth in the revised Tariff reflect this estimated ATWACC of 8.85%.

4. Subsequent Year Changes to Gross CONE.

PJM uses a composite index of generation plant capital costs to adjust the Gross CONE values each year between quadrennial reviews. The composite, as prescribed by the current Tariff, weighs cost indices published by the U. S. Department of Commerce's BLS for labor (20%), turbines (25%), and materials (55%).[143] The Commission accepted annual adjustments in the 2018 Review Order as "well supported and reasonable."[144]

PJM proposes to continue to rely on these same three cost indices, but to change their weightings to better accord with the new Gross CONE estimate of CC plant capital costs. As shown in the Brattle 2022 CONE Report, the estimated capital costs for the CC plant entering service in 2026 break down as approximately 40% labor, 15% turbines, and 45% materials.[145] Accordingly, to escalate that plant cost estimate for the subsequent three years, PJM proposes to weight the indices as 40% labor, 15% turbines, and 45% materials. This change is shown as a revision to the weighting values stated in Tariff, Attachment DD, section 5.10(a)(iv)(B)(4).

5. The 20-Year Amortization Period Remains Appropriate.

To determine the Net CONE for a CONE Area, PJM amortizes the cost of building the Reference Resource over a 20-year period. PJM has utilized this approach since the inception of RPM, and no state policy currently mandates the retirement of generation within that economic horizon.

PJM is cognizant that, recently, the Illinois state legislature passed the Climate and Equitable Jobs Act ("CEJA"),[146] which would require resources to adopt an emission-free technology by 2045.[147] Although a 20-year asset life beginning in 2026 would end in 2046, PJM's 20-year asset life amortization period remains appropriate for all CONE Areas.

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[141] *Id.*

[142] *Id.*

[143] Tariff, Attachment DD, section 5.10(a)(iv)(B)(1).

[144] 2018 Review Order, 167 FERC ¶ 61,029, at P 75.

[145] 2022 CONE Report at 61.

[146] 2021 Ill. Laws 662.

[147] 415 Ill. Comp. Stat. 5/9.15(k) (2022).

While the provisions of CEJA may impact the natural gas fleet in Illinois, it would not be appropriate to, at this time, make any "one-off" adjustment isolated to this particular law. For one, the Commonwealth Edison Company ("ComEd") transmission zone in Illinois is but one portion of CONE Area 3. In fact, CONE Area 3 includes nine other transmission zones, and includes all or parts of Ohio, Illinois, Indiana, Kentucky, Virginia, North Carolina, Pennsylvania, and Michigan.[148] Given that gas-fired resources within the ComEd transmission zone in the state of Illinois make up a fraction of the expected overall generation fleet, modifying the 20-year asset amortization period for CONE Area 3 to account for so small an impacted group of generators would constitute an excessive overcorrection. Further, requiring PJM to modify the amortization period for only CONE Area 3 would affect the calculation of Net CONE across all CONE Areas and could result in discriminatory outcomes.

Were PJM to now isolate the ComEd Zone from CONE Area 3 based on CEJA, PJM would logically then need to examine and interpret the policies in each and every state, and establish CONE levels for each state or even localities to the extent those state policies could affect the economic life of units in that area. While such a hyper-local approach may be appropriate in a single-state capacity market, in a multi-state region such as PJM, customers in adjoining states would face the prospect of one state's policies unduly affecting other states and causing them to bear the costs of other states' choices as a result. In the alternative, the CONE analysis and RPM would essentially become "de-constructed" into separate areas based on state and local policies. In short, there would be no limiting principle that would effectively cabin this inquiry if PJM were to undertake a special adjustment for the CEJA law in this proceeding.

That is not to say that a broader inquiry as to the impact of specific state laws affecting the economic lives of units should not be considered. However, such an inquiry would be much larger than simply examining the impact of Illinois' CEJA. As a result, this issue, which was only raised by stakeholders after the completion of the Brattle analysis and at the very end of the stakeholder process, is best addressed generically by PJM outside of the quadrennial review rather than as a "one-off" adjustment at this time.

Finally, specific to CEJA, it should be noted that the law does not itself require the retirement of resources. Rather, CEJA is focused on emissions reduction and abatement of carbon emissions and other co-pollutants. As a result, with its focus on emission limits, CEJA is not sufficiently different from any other state or federal pollution controls imposed on generating resources. In any event, CEJA is currently subject to a preliminary injunction that enjoins the Illinois Environmental Protection Agency "from applying its rules and interpretation of CEJA" to at least one gas-fired resource in Illinois.[149]

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[148] Specifically, CONE Area 3 includes the following transmission zones: AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, and OVEC.

[149] *Elwood Energy LLC v. Ill. EPA*, No. 2022-CH-50 (Cir. Ct. for the 7th Jud. Cir., Sept. 12, 2022) (also finding Illinois "EPA's attempted rule and interpretation of CEJA is invalid and not enforceable.").

For all of these reasons, the Commission should avoid a "one-off" approach to this issue given the multi-state nature of the RTO and the fact that RPM is focused on the costs of a hypothetical reference resource to be built in a very large area rather than a focus on any specific existing unit or set of units in a particular state or locality. As a result, the 20-year asset life amortization period across all CONE Areas therefore remains appropriate to calculate Net CONE based on this record.

D. Energy and Ancillary Services Methodology.

1. Background.

The current-effective Tariff directs PJM to estimate the energy revenues that the Reference Resource would have received based on actual Locational Marginal Pricing ("LMP") and fuel prices for the most recent three calendar years, the heat rate of the Reference Resource, and an assumption that the Resource would be dispatched for both the Day-ahead and Real-time Energy Markets on a "Peak Hour Dispatch" basis.[150] The Tariff directs PJM to then add ancillary service revenues of $2,199 per MW-year.[151]

PJM carefully considered a number of changes to this EAS Offset methodology during the Tariff-prescribed analysis and stakeholder process. PJM and its experts evaluated the existing backward-looking approach for estimating energy market revenues and the omission of revenues for providing market-based ancillary services (i.e., Synchronized Reserve, Non-synchronized Reserve, and Secondary Reserve).

Based on the information, analysis, and stakeholder input gathered in the quadrennial review process, the PJM Board chose to reinstate the forward-looking methodology for determining the EAS Offset that the Commission found just and reasonable in Docket No. EL19-58.[152] As approved there, and re-proposed here, PJM's forward-looking methodology has three main components:

- Using publicly available energy and fuel price data from liquid forward markets for the same timeframe as the Delivery Year at issue, applying locational adjustments and hourly (for energy) and daily (for fuel) price shaping using commercially reasonable and customary methods;
- Running a resource revenue model, known as the Projected EAS Dispatch Model, with the forward-based energy, ancillary services, and fuel prices and key resource characteristics and parameters as inputs and with the

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[150] Tariff, Attachment DD, section 5.10(a)(v)(A).

[151] Tariff, Attachment DD, section 5.10(a)(v)(A).

[152] *See PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,134, at P 247 (2020) ("EL19-58 Forward EAS Compliance Order"), *reh'g denied*, 174 FERC ¶ 61,180 (2021).

objective of committing and dispatching a resource for the purpose of maximizing its net revenues; and

- Adding cost-based reactive service revenues.

The resulting simulated generation pattern and the corresponding revenues net of operating costs for each day of the Delivery Year, followed by a settlement calculation and addition of cost-based reactive service revenues, yield the projected EAS Offset for the CC Reference Resource. PJM will perform this simulation with energy, ancillary services, and fuel prices shaped by historical data from each of the three full preceding calendar years, and then take the average of the revenues yielded by the three simulations as the EAS Offset value for the CC Reference Resource on which Net CONE in the VRR Curve is based.

2. Overview of Proposed Forward-Looking EAS Offset Approach.

As noted, the Commission has already found PJM's forward-looking EAS Offset approach, and its inputs, to be just and reasonable in Docket No. EL19-58-003.[153] As discussed below, the Commission made specific findings as to a number of PJM's specific inputs,[154] modelling assumptions,[155] transparency and level of detail,[156] and the determination of the "RTO" Net CONE used to determine the RTO VRR Curve.[157]

PJM is proposing the same EAS Offset methodology the Commission found just and reasonable, with only a few exceptions. One, PJM is proposing to determine estimated future Synchronized Reserve and Non-Synchronized Reserve revenues by scaling historical reserve prices using forward energy prices.[158] Two, PJM is not proposing to include revenues from providing Regulation service, because, as Brattle explains, "the market is too small at only 500-800 MW," and it is likely that "new entrants could not earn major revenues from the small market."[159]

Basing the VRR Curve shape on a forward-looking Net CONE results in price signals from the capacity markets that are consistent with investor decisions of expected market conditions.[160] Further, the Commission has held that "[a] forward-looking E&AS Offset is the best expectation of energy and ancillary services revenues in the given delivery

[153] *See* EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 247.

[154] *See* EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at PP 92-150.

[155] *See* EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at PP 160-71.

[156] *See* EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at PP 156-59.

[157] *See* EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at PP 151-54.

[158] PJM is not including the 10% cost adder that had been previously included for CT resources only.

[159] 2022 CONE Report at 52.

[160] *See PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, at P 320 (2020) ("[A] forward-looking methodology is consistent with project valuation methods used by market participants.").

year and should therefore include the effects of any large market changes that are expected to be in place in the given delivery year."[161]

While the Commission later reversed its acceptance of reserve market changes underpinning the requirement for a forward-looking EAS Offset and directed PJM to reinstate its historical EAS Offset approach, the Commission expressed that it is "not determining that a forward-looking E&AS Offset is unjust and unreasonable."[162] Indeed, the Commission did not repudiate any of its prior findings regarding the elements of PJM's approach, and accordingly, the Commission's prior findings continue to apply.

3. PJM's Proposed Forward-Looking EAS Offset Approach Is Just and Reasonable and Is Almost Identical to the Approach the Commission Found Just and Reasonable in Docket No. EL19-58.

PJM is proposing a forward-looking approach to determine the net revenues that a resource can reasonably be expected to earn in PJM by providing EAS. To that end, PJM proposes to sunset the existing tariff provisions used currently calculate EAS revenues based on a historical rolling average, and update the previously accepted tariff provisions, used only for capacity auctions for the 2022/2023 Delivery Year, setting forth a forward-looking EAS Offset methodology.[163]

A forward-looking approach necessarily relies on forward-looking data, and PJM's approach is grounded in forward energy and fuel prices at liquid trading points for the subject Delivery Year. PJM's proposed approach forecasts EAS revenues using a Projected EAS Dispatch Model, as explained in detail below, to strengthen the connection between liquid forward market prices and expected resource revenues. This dispatch model is more consistent with commercial expectations of the revenue a resource can reasonably expect to earn in PJM's EAS markets. Indeed, similar to PJM's Day-ahead and Real-time EAS markets, which employ a co-optimization algorithm to achieve the least-cost solution for simultaneously meeting energy demand and reserve requirements, PJM's proposed Projected EAS Dispatch model employs a similar approach for determining EAS

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[161] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, at P 324.

[162] *PJM Interconnection, L.L.C.*, 177 FERC ¶ 61,209, at P 25 (2021); *see also id.* at P 46 ("To be clear, we are not finding that a forward-looking E&AS offset is unjust and unreasonable or that PJM cannot propose a forward-looking E&AS offset. Instead, we find only that the Commission lacks a basis to impose such an offset under section 206 on the present record.").

[163] The scope of this quadrennial review is limited to the updated calculation of Net CONE for the Reference Resource. Accordingly, in this filing, PJM is not proposing to apply a forward-looking EAS Offset for market mitigation purposes (i.e., Market Seller Offer Cap and Minimum Offer Floor Price). PJM and its stakeholders are in the process of separately considering the application of forward-looking EAS Offsets for such purposes and will address any potential changes in a separate filing. As such, the Tariff language proposed in this filing makes clear that the historical EAS Offset is retained for market mitigation purposes. *See* proposed Tariff, Attachment DD, section 5.10(a)(v).

revenues for the Reference Resource.[164] In addition, the Reference Resource will continue to be credited with revenues for providing reactive service.

As a result, under PJM's proposed approach, the Net CONE used to determine the VRR Curve will better reflect the estimated costs that a new Reference Resource would need to recover through the capacity market.

4. PJM's Proposed Approach Bases EAS Offset Estimates for a Delivery Year on the Energy and Fuel Prices in Liquid Futures Markets for the Time Frame of that Delivery Year.

The Commission has found that "[a] forward-looking [EAS] Offset is the best expectation of energy and ancillary services revenues in the given delivery year and should therefore include the effects of any large market changes that are expected to be in place in the given delivery year."[165] The Commission has also endorsed the view that a forward-looking EAS Offset "would 'provide a better representation of a developers' expectations for net energy revenues,'"[166] finding that a forward methodology "is consistent with project valuation methods used by market participants."[167]

PJM's proposal is grounded in these findings, and proceeds from this guidance. Echoing the Commission's views, the Brattle experts "recommend that PJM adopt the principles and methods that are consistent with commercial practices, as we would use when supporting a client in an investment or contract decision for a similar timeframe," including "rely[ing] on market prices to the extent they are observable."[168] The Brattle experts accordingly "recommend using forward prices for delivery of electric energy and natural gas to PJM market participants" which "reflect expectations of market conditions at contract delivery dates and locations, and thus should incorporate assessments of the many factors that will determine prices at delivery, including such factors as fuel supply and demand, additions and retirements of generation and transmission capacity, and changes to market design."[169]

Several important design parameters flow from these principles, and shaped PJM's approach. First, the forward prices used in the EAS revenue estimates are best taken from liquid futures markets. When markets are liquid (i.e., there are substantial numbers of both buyers and sellers), settlement prices will better reflect Market Participants' expectations

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[164] As discussed below, because there are no observable forward ancillary services markets, PJM will use market or cost-based prices for ancillary services, as appropriate.

[165] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, at P 324.

[166] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, at P 321 n.696 (quoting 2018 Review Order, 167 FERC ¶ 61,029, at P 114).

[167] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, at P 320.

[168] Brattle EAS Aff. ¶ 15.

[169] Brattle EAS Aff. ¶ 15.

about future conditions. Such markets also post their settlement prices publicly, and mark to market daily, allowing current and prospective Market Participants to see the market's current collective judgment on expected future conditions and to react to those prices based on their own expectations of future conditions, and their knowledge of their own plans, transactions, and operations. Consistent with this important condition, the Brattle experts carefully assess market liquidity, and propose reliance on particular market hubs and products that trade with sufficient liquidity.

Second, futures market products, locations, and time periods do not automatically supply every assumption needed for every EAS Offset estimate required by the Tariff. Other forward markets can help fill some of those gaps, such as PJM's long-term Financial Transmission Rights ("FTR") auctions, which usefully reveal market expectations about future locational (congestion-based) price differences. For other aspects of the analysis, patterns established in historic data are reasonably used to adapt the output of futures markets to meet the need for particular inputs to the EAS Offset estimate.

Third, because "[t]he price of natural gas . . . is one of the principal drivers of electric energy prices," and "forward electricity prices on any given date will reflect forward natural gas prices on that same date," the forward EAS estimating methodology should be "sensitive to the alignment of forward price observation dates and forward contract delivery dates for power, natural gas, and other relevant fuel commodities," and thereby "avoid systematic errors in forecasts of EAS margins."[170]

As explained in the following subsections, PJM's proposed use of energy and fuel prices in the EAS Offset estimating methodology takes account of these principles.

a. Forward electric energy prices.

PJM's forward EAS Offset methodology relies on futures markets prices. As explained by the Brattle experts, the established futures markets are well-suited to this purpose because:

- they are "marked to market and resettled on a daily basis;"
- they "determine a settlement price for each contract on each business day;" and
- "the sponsoring exchange makes its futures settlement prices public."[171]

The futures markets also trade multiple electric energy and natural gas products for delivery at multiple times and multiple locations in the PJM Region, and thus provide abundant, current, public data on forward prices needed for a forward EAS estimate.

[170] Brattle EAS Aff. ¶ 47.

[171] Brattle EAS Aff. ¶ 44.

However, not all of those products, locations, and delivery periods exhibit the liquidity desired for a reliable forward EAS estimate. The Brattle experts therefore assessed liquidity for multiple alternatives, and identified those with sufficient liquidity to use as a source of forward prices. Liquidity, which is essentially trading interest, can and will change over time. 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 and use, over time, of this forward-looking EAS Offset. Therefore, rather than locking in a fixed set of trading hubs or requiring the Commission to adjudicate in future proceedings the liquidity of individual trading hubs on a hub by hub basis, PJM is not proposing to embed in the Tariff, at least at this time, the specific products and hubs that the consultants identified in this summer's analysis. Rather, PJM proposes to reflect in the Tariff that the particular hubs used for the EAS Offset will be specified in the PJM Manuals.[172] The Commission has agreed with this approach, finding "[b]ecause details such as the liquidity of electricity hubs may change over time, it is reasonable for PJM to specify such details in PJM Manuals."[173]

The Brattle experts use "open interest" as a gauge of futures market liquidity. Open interest in a futures market trading contract (i.e., a particular product for delivery at a particular place and time) "reflects the cumulative number of contracts that have been opened but not yet closed out or offset."[174] The Brattle experts explain that "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."[175] Moreover, "greater open interest and contract trade volumes reduce the chances that market prices can be manipulated successfully."[176] The Commission, too, has recognized that "[p]rices from liquid futures markets (i.e., those with many buyers and sellers, as determined by open interest) produce forward prices that reflect expectations about future conditions."[177]

For their liquidity analysis, the Brattle experts considered the open interest "at each of the trading hubs and transmission zones in PJM for which [Intercontinental Exchange,

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[172] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(1). Under the Commission's "rule of reason," only matters that significantly affect rates, terms, and conditions of service, or that are reasonably susceptible to specification, must be included in the Tariff. *See City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985). Accordingly, for this reason, it is well understood that "study assumptions and parameters are likely to change over time as planners gain experience in implementing the new planning procedures. Thus, rigid specifications or formulas set out in the Tariff would likely lead to less reliable assessments due to the inability of planners to adapt to changing circumstances." *Sw. Power Pool, Inc.*, 136 FERC ¶ 61,050, at P 37 (2011). Likewise, here PJM is including in the Tariff the formula and process for identifying the relevant hubs, but is not "hardwiring" the specific hubs into the Tariff.

[173] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 159.

[174] Brattle EAS Aff. ¶ 45. To be clear, there is a futures contract with a buyer and seller; the interest is "open" only because it has not yet gone to delivery or been liquidated.

[175] Brattle EAS Aff. ¶ 46.

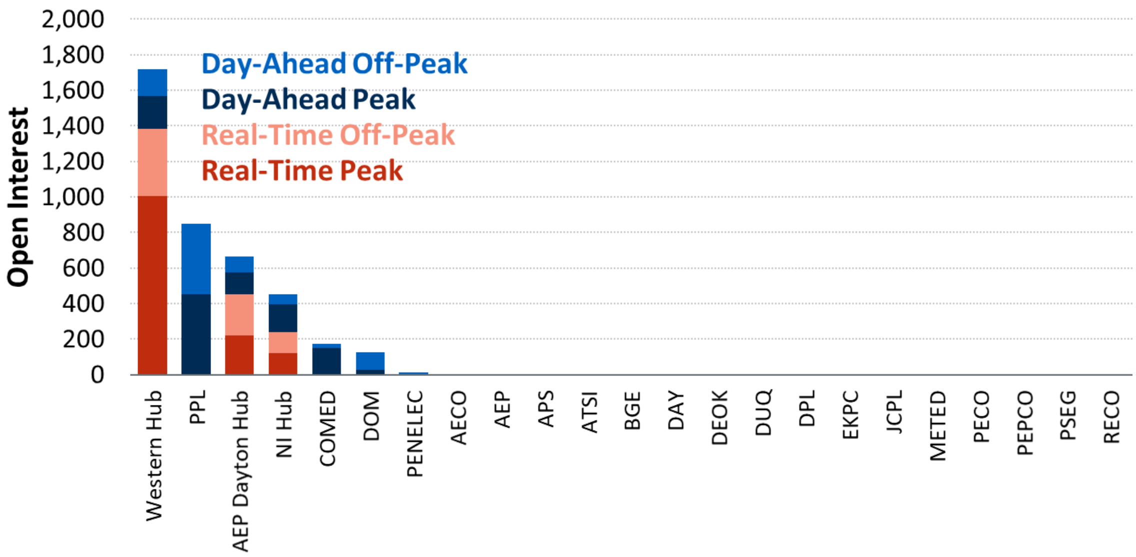
[176] Brattle EAS Aff. ¶ 46.

[177] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 102.

Inc. ("ICE")] lists futures contracts."[178] To measure open interest, they considered all products in the same product family (i.e., day-ahead peak, day-ahead off peak, real-time peak, and real-time off peak) because "settlement prices for long-dated day-ahead and real-time futures contracts. . . are nearly identical," and "the aggregate level of activity [for the related products reasonably] inform[s] the level of liquidity."[179] For both the forward price and liquidity analyses, Brattle reviewed prices for 2024, reflecting that PJM typically will undertake its pre-auction EAS revenue estimating analyses roughly four years before the relevant Delivery Year.[180]

The results of their liquidity analysis are shown in Figure 3 below, which is taken from the Brattle EAS Affidavit.

Figure 3: Monthly Average Open Interest for PJM Futures Products at Trading Hubs and Zones for Delivery Year 2026/27



As can be seen, open interest for these PJM energy products in the 2026/2027 Delivery Year is substantial for the three traded PJM Region hubs, but minimal to non-existent for the 20 traded PJM Region zones. Looking beyond 2026/2027 to additional years, the Brattle experts also note that open interest at the PJM Zones is "inconsistent from year to year."[181] Based on these facts, in their affidavit, they recommend electric energy

[178] Brattle EAS Aff. ¶ 48. They also checked open interest on electricity contracts traded on New York Mercantile Exchange platforms, but found it was more limited than open interest on the ICE. *See id.*

[179] Brattle EAS Aff. ¶ 48.

[180] *See* Brattle EAS Aff. ¶ 49.

[181] Brattle EAS Aff. ¶ 49.

futures settlement prices at PJM Western Hub, AEP-Dayton Hub, and Northern Illinois Hub for the forward EAS estimates.[182]

PJM's approach, per the Brattle experts' recommendation,[183] averages the settlement prices reported for the 30 most recent trading days.[184] This approach "balances the benefit of the most recent market information with potential vulnerability to market manipulation from indexing to a single day."[185] To implement the recommended 30-day averaging, PJM plans to retrieve, 180 days before the start of each Base Residual Auction, forward pricing data for each month of the future Delivery Year, and will use the daily settlement data from the 30 trading days prior to that date. This will provide PJM with time to calculate the EAS Offsets for the Reference Resources prior to having to post the preliminary default MOPR Floor Offer Prices at 150 days prior to the auction. The Commission found PJM's use of "forward prices averaged over the 30-day period that ends 180 days before the BRA to be just and reasonable,"[186] because "[a]veraging futures prices over 30 days provides a larger sample size of futures prices that is likely both to be influenced less by any short-term price volatility and to make the futures price average less susceptible to manipulation."[187]

PJM also proposes to use the day-ahead product's future prices. As the Brattle experts explain, the day-ahead and real-time futures prices "are nearly the same, so choosing to rely on one versus the other will have little to no impact on the estimated EAS net revenues."[188] The Commission has agreed with this conclusion and accordingly found the "use [of] day-ahead prices instead of real-time prices is just and reasonable."[189] Moreover, the monthly prices from the day-ahead futures can be used to develop both hourly day-ahead prices and hourly real-time prices, relying on the distinct patterns of day-ahead and real-time hourly price shapes in the recent historic record, as discussed below. Thus, PJM proposes to continue the use of day-ahead product prices.

In sum, the end result of this step of the analysis is forward day-ahead energy prices for each of the three PJM hubs, and for each month, on-peak period, and off-peak period in the Delivery Year.

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[182] *See* Brattle EAS Aff. ¶ 49.

[183] *See* Brattle EAS Aff. ¶ 24. Note that the daily interval here refers to settlement price updating. The underlying product is monthly (e.g., delivering energy at the specified location every day for the month of July 2024).

[184] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(2).

[185] Brattle EAS Aff. ¶ 24.

[186] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 114.

[187] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 115.

[188] Brattle EAS Aff. ¶ 24; *see* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(2).

[189] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 104.

b. Determination of zonal prices.

i. Mapping from liquid hubs to transmission zones

As noted above, there is little trading of day-ahead or real-time energy futures for delivery to individual PJM Zones in the 2026/2027 Delivery Year, and the little trading observed is inconsistent from year-to-year. The Brattle experts correctly observe that "[t]he limited liquidity of zonal futures makes them more vulnerable to manipulation."[190] While the zonal futures prices themselves should therefore be avoided in the analysis, fairly high correlations in historic prices between each hub and specific Zones enable ready mapping of Zones to hubs.

Specifically, the Brattle experts "analyzed the correlation of historical prices between the three electricity hubs and the 20 PJM zones, using monthly average peak and off-peak data for DY 19/20–DY 21/22," and found that "for each zone, the hub with highest price correlation is that which is geographically closest," and this correlation persisted for both peak and off peak prices.[191] The resulting hub-to-zone mapping is shown in the Brattle Affidavit.[192] The Commission agreed, finding "map[ping] the liquid trading hubs to specific PJM Zones to be just and reasonable due to the high correlations in historic prices between each hub and specific PJM Zones."[193]

However, this mapping does not mean that PJM proposes simply to adopt for each Zone the price in the hub to which it is mapped. Rather, this mapping defines the appropriate sources and sinks for determining locational basis differentials between each Zone and its mapped hub. Adding these differentials to the mapped hub price determines the corresponding Zone price.[194]

ii. Long-term FTR auction results used to calculate forward monthly peak and off-peak prices for each Zone

PJM proposes to maintain the use of forward market information (i.e., long-term FTR auction results), along with historic data on marginal losses, to calculate forward monthly peak and off-peak prices for each Zone.[195] This is not a novel approach. As the Brattle experts explain, their "standard practice" for estimating future congestion differentials a few years out "is to use differences in congestion prices between each zone

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[190] Brattle EAS Aff. ¶ 49.

[191] Brattle EAS Aff. ¶ 51.

[192] Brattle EAS Aff. ¶ 51 & Table 5.

[193] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 102.

[194] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(3).

[195] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(3).

and the hub, from the latest long-term [FTR] auction."[196] The Commission also found this approach of "us[ing] long-term FTR prices to estimate part of the locational differences to apply to the forward prices at the futures trading hubs [to be] just and reasonable."[197]

The longest-term FTRs traded in PJM's auctions are three years forward.[198] Even allowing for the fact that the latest long-term FTR auction results available at the time of PJM's EAS Offset calculations will be for the Delivery Year prior to that for which the Base Residual Auction is being run, "[t]he long-term FTRs are a reasonable indicator of the market's expectations of congestion in the [D]elivery [Y]ear and will reflect shifting congestion patterns much more quickly than, for example, relying on historical congestion differentials from four to six years before the [D]elivery [Y]ear."[199]

As the Brattle experts explain, PJM's "long-term FTR auctions are centralized, multilateral, and locational-based markets, producing nodal clearing prices . . . . determined by bids from many market participants for source-sink pairs across the PJM system;" and have been found competitive, with ownership unconcentrated.[200] The consultants also "analyzed how well historical long-term FTR prices align with realized congestion in the day-ahead market between the trading hubs and zones during the same delivery years for 2011/12 to 2021/22."[201] Although "[l]ong-term FTRs may not correctly predict realized congestion in the delivery year because there is substantial uncertainty about the market conditions . . . FTR prices do incorporate predictable changes . . . [and therefore] [u]sing FTR prices to forecast basis differentials can incorporate such changes sooner than trailing historical prices."[202]

The Commission recognized that "the purpose of using FTR data is to capture congestion trends, not to calculate accurate estimates of congestion,"[203] and found PJM's "methodology to use congestion expectations from FTR data is a just and reasonable approach for constructing zonal price forecasts."[204]

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[196] Brattle EAS Aff. ¶ 25.

[197] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 133.

[198] *See* Tariff, Attachment K – Appendix, section 7.1A.1; Operating Agreement, Schedule 1, section 7.1A.1.

[199] Brattle EAS Aff. ¶ 25.

[200] Brattle EAS Aff. ¶ 52.

[201] Brattle EAS Aff. ¶ 53.

[202] Brattle EAS Aff. ¶ 53.

[203] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 136.

[204] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 134.

iii. Shaping annual prices by month using congestion

Because PJM's long-term FTR product is annual, the auction prices need to be adjusted to obtain monthly values for the EAS Offset estimates.[205] For this purpose, "[i]t is reasonable to shape these annual prices by month using the congestion component of monthly average day-ahead price differentials between the zone and relevant hub from the past three years."[206]

To do this, PJM proposes to add "for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub."[207]

In addition to the congestion differences, Zonal prices also need to incorporate the marginal losses expected between the hub and its mapped Zones. This adjustment is reasonably performed using historical zonal day-ahead loss prices (scaled by the relationship between the forward price at the hub and the historic day-ahead LMP for the hub.[208] Such use of historic loss data "[is] sufficient because losses tend to be relatively small and more stable than energy prices, and there is no forward-looking, market-based source for directly estimating future losses."[209]

Specifically, PJM proposes to calculate the added loss differential "as the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period."[210]

The end result of these steps of the analysis is forward day-ahead energy prices for each of the 20 PJM Zones, and for each month, on-peak period, and off-peak period in the Delivery Year.

c. Forward natural gas prices.

Fuel costs are a critical input to the EAS revenue estimates as they are the principal cost incurred by most resources to obtain energy revenues. For the forward EAS Offset methodology, PJM proposes to maintain using fuel futures market prices in a manner

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[205] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(3).

[206] Brattle EAS Aff. ¶ 25.

[207] Tariff, Attachment DD, section 5.10(a)(v-1)(C)(3).

[208] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(4).

[209] Brattle EAS Aff. ¶ 26.

[210] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(4).

similar to the proposed methodology's use of electric energy futures market prices. Because the Reference Resource assumed for setting the VRR Curve is natural gas-fired, PJM and its consultants evaluated natural gas prices.

As with energy futures prices, there are multiple futures markets for natural gas deliveries to PJM Region locations, but the liquidity of those markets varies over the 3.5-to-4.5 year forward time period used to match the energy futures prices. As with electric energy futures, open interest is also reported for these natural gas futures trading hubs, which enables a reasonable assessment of liquidity. As explained in their affidavit, the Brattle experts found six gas hubs with sufficient liquidity (i.e., Chicago, Transco Zone 6 (non-NY), Dominion South, Michcon, TETCO M3, and Columbia-Appalachia TCO),[211] based on the open interest results summarized in their Figure 4.[212]

The PJM Region is also served by three other natural gas hubs, (i.e., Transco Zone 6 (NY), Tennessee 500L, Transco Zone 5 Delivered) but their 2029 futures markets are not sufficiently liquid to rely on their settlement prices. However, based on historical price correlations, each of these hubs can be mapped to one of the six hubs that is sufficiently liquid in the examined futures market.[213] Once mapped, forward prices for these less-liquid hubs can be derived "by scaling the forward price of the mapped hub by the average ratio of monthly prices at the illiquid hub and the mapped [liquid] hub over the most recent three years."[214] This reliance on historic data is reasonable. The three hubs are only illiquid *in the futures market*; the locations were actively traded in the historic period, permitting reasonable assessment of the relationship between prices at these hubs and prices at the hub to which they are mapped.

In accepting this approach previously, the Commission found "PJM's proposal regarding the selection of natural gas pricing hubs [] just and reasonable."[215] Specifically, the Commission rejected claims that PJM did not sufficiently use correct criteria for hub selection, finding that "PJM reasonably relies on the analysis of Brattle and S&L, including on the consultants' explanation of their methodology included in their report, to identify six natural gas hubs with sufficient liquidity."[216] The Commission similarly found "that PJM reasonably relies on the consultants' methodology for mapping three illiquid gas pricing hubs to one of the six liquid hubs based on historical price correlations."[217] Here, PJM and its consultants provide generally the same detail, explanation, and justification for natural gas price hub selection and mapping to each transmission zone.

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[211] Brattle EAS Aff. ¶ 61.

[212] Brattle EAS Aff. ¶ 61 & Figure 4.

[213] *See* Brattle EAS Aff. ¶ 62.

[214] Brattle EAS Aff. ¶ 35.

[215] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 145.

[216] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 145.

[217] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 145.

PJM proposes to use a simple average of natural gas settlement prices for the most recent 30 trading days, for the same reasons noted above for the forward energy prices.[218] Specifically, PJM will retrieve the forward gas price data 180 days before the relevant Base Residual Auction, and use data from the 30 preceding trading days at that time.[219]

Finally, PJM will assign prices from the nine natural gas futures trading hubs to the 20 PJM Zones using the hub-to-zone mapping previously developed and recorded in PJM Manual 18. PJM has memorialized the prior version of this mapping in Manual 18, section 3.3.2.[220] For the reasons presented by Brattle, PJM plans to update Manual 18 to map the EKPC Zone to MichCon natural gas pricing hub.[221]

d. Shaping futures market monthly prices to the hourly and daily prices needed to make resource revenue estimates.

The steps above produce monthly forward prices for electric energy and natural gas. Estimating resource revenues, however, requires prices on a shorter timescale, to capture the changing operating and economic conditions that drive resource dispatch, output, and revenues. Energy prices by hour, and natural gas prices by day, provide reasonable granularity for purposes of the estimate given this matches the timescale of the day-ahead energy and gas markets. Historic data can help fill this gap.

For this purpose, one could shape monthly prices to hourly prices based on historic multi-year relationships, and then run the dispatch model using those prices. Different years will exhibit different pricing patterns; simply averaging price variations across multiple years will mute the in-year volatility that significantly affects resource revenues. Such an approach also would not sufficiently respect the strong relationship between electric energy prices and fuel prices. Trying to match, for example, a multi-year average pattern of gas prices to a multi-year average pattern of energy prices could ignore that a strong natural gas price trend produced a strong energy price trend. A synthetic year that tries to encompass multi-year pricing pattern variations thus may be *too* synthetic, and therefore less realistic. As the Brattle experts explain, "[h]istorical price patterns provide the best information for the hourly shapes of day-ahead and real-time prices," which warrants "using the price patterns from each of the three most recent years to capture random variation in price shapes from year to year."[222]

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[218] Brattle EAS Aff. ¶ 36.

[219] As noted, the Commission found the "use forward prices averaged over the 30-day period that ends 180 days before the BRA to be just and reasonable." EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 114.

[220] *See PJM Manual 18: PJM Capacity Market*, PJM Interconnection, L.L.C., 34-35 (Sept. 21, 2022), https://www.pjm.com/-/media/documents/manuals/m18.ashx.

[221] *See* Brattle EAS Aff. ¶ 62.

[222] Brattle EAS Aff. ¶ 27.

For this reason, PJM's approach is more sophisticated, which uses historic pricing patterns from each of the three most recent years to produce three years of shaped hourly energy forward prices and shaped daily natural gas forward prices, and *then* run the revenue model separately for *each* of those years. Under this approach, the revenues resulting from those three years are averaged to produce an annual EAS estimate that reasonably encompasses varying patterns in hourly energy or daily natural gas prices.[223] PJM will produce hourly energy prices for each Zone, for each applicable generation bus,[224] and for the PJM Region.[225] To determine the PJM Region forward energy prices, PJM will take the load-weighted average of the monthly on-peak and off-peak Zonal LMPs, developed using the historical average load for each on-peak and off-peak period. Then, PJM will shape those monthly values to Forward Hourly LMPs using the same shaping process for zonal Forward Hourly LMPs, but use historical LMPs "for the PJM Region pricing point," i.e., (Pricing Node ID 1: PJM-RTO).[226]

Specifically, PJM proposes to:

- Separately consider hourly electric energy prices and daily gas prices from each of the three most recent years, for three separate analyses;

- For each monthly on-peak period and off-peak period within a given historic year, develop an hourly energy price shape by dividing each individual hour's Day-ahead or Real-time LMP by the average Day-ahead or Real-time LMP across all hours in the given period;[227]

- Apply that shape to the corresponding monthly on-peak period or off-peak period day-ahead price developed from the energy futures markets in the steps described above, to produce hourly energy prices for each hour in those periods, and thus for each hour of the year;[228]

- Develop daily natural gas price shapes in the same way, deriving in-period daily price patterns for each month of the historic year, and applying those patterns to the corresponding monthly prices developed from the natural gas futures markets;[229]

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[223] *See* Tariff, Attachment DD, sections 5.10(a)(v-1)(C)(5) & 5.10(a)(v-1)(E)(5).

[224] PJM will also determine prices to each applicable generation bus for use in determining resource-specific EAS Offsets by applying basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6).

[225] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(7).

[226] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(7).

[227] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(5).

[228] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(C)(5).

[229] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(E)(5).

- Use the shaped forward hourly energy prices and shaped forward daily natural gas prices developed using shapes from each historic year;[230]

- Calculate net EAS revenues for each of those years using the appropriate model for the resource under consideration;[231] and

- Average the resulting three years of revenues to produce a single-year estimate.[232]

The Commission evaluated PJM's proposal "to produce a single-year estimate that encompasses varying patterns in hourly energy prices and daily natural gas prices"[233] and found that it produced a just and reasonable forward-looking EAS Offset.[234] The Commission rejected arguments against the use of RTO average prices in the dispatch model for the Reference Resource, holding "PJM's proposal to use RTO average prices is consistent with its prior approach and the existing Tariff."[235]

5. PJM Proposes to Use Market-Derived Ancillary Services Revenues to the EAS Offset.

In addition to considering forward price data for energy and fuel, PJM is proposing to account for revenues from three market-based ancillary service products in the EAS Offset, i.e., Synchronized Reserve, Non-synchronized Reserve, and Secondary Reserve (but not for Regulation). The current historical EAS Offset approach omits revenues from such ancillary services, and instead only considers the cost-based revenues from providing reactive service as the representative of the estimated ancillary services revenues.[236] Accordingly, PJM is proposing to continue to provide credit for reactive services *and* start to account for revenues from other market-based ancillary services in the EAS Offset.

However, PJM is not proposing to include revenues for Regulation service in the EAS Offset. As Brattle explained in the 2022 CONE Report and their EAS-specific affidavit, the Regulation market is "too small at only 500-800 MW (some of which is already absorbed by [battery storage] providing the premium RegD product" to meaningfully impact the EAS Offset determination.[237] That is, not only is the Regulation market too small to provide significant revenue for the over 170,000 MW of capacity resources, even "[i]f the [Regulation] revenues per plant were high, the first few plants

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[230] *See* Tariff, Attachment DD, sections 5.10(a)(v-1)(C)(5) & 5.10(a)(v-1)(E)(5).

[231] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(A).

[232] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(A).

[233] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 151.

[234] *See* EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 154.

[235] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 154.

[236] *See* Tariff, Attachment DD, section 5.10(a)(v-1)(A).

[237] 2022 CONE Report at 52.

would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate."[238] Accordingly, PJM does not propose to consider Regulation in the EAS Offset at this time. PJM's proposal here under FPA section 205 does not foreclose consideration of Regulation revenues in the future, as facts warrant.

To estimate the revenues for the other market-based ancillary services, PJM will use the Projected EAS Dispatch model (discussed in the next section) that co-optimizes energy and reserves, similar to PJM's Day-ahead and Real-time Energy Markets. However, as Brattle explains, there are no observable forward markets for such ancillary services at this time, so PJM must rely on historical market prices for ancillary services.[239]

As PJM, Brattle worked on putting together a process to estimate forward ancillary services prices, the primary method discussed was to scale historic reserve market clearing prices by the ratio of the forward energy prices to the historic energy prices because "[t]here are no observable forward markets for ancillary services."[240] As Brattle explains, energy prices have historically been highly correlated with reserve market prices.[241] To determine the applicable prices for Synchronized Reserve and Non-Synchronized Reserve, PJM will rely not only on historical prices for such products but historical and projected energy prices as well to develop the forward reserve prices. This is because Brattle demonstrates that the relationship between energy and reserve prices appears to have been "roughly linear"[242] that can be used to scale historical hourly prices to the percent change in future energy prices relative to the corresponding historical prices.[243] Accordingly, the hourly forward reserve prices are derived by "scaling" historical real-time prices for Synchronized Reserve and Non-Synchronized Reserve "by the ratio of the monthly day-ahead peak/off-peak futures prices to the historical monthly average day-ahead peak or off-peak prices relevant for each hour."[244] PJM will use the Western pricing hub in PJM as the "appropriate pricing point" to perform the comparison between historical and forward LMPs.[245]

For Synchronized and Non-synchronized Reserves, PJM will employ the derived hourly forward prices for these reserves in the Projected EAS Dispatch, where they will interact with the Forward Hourly LMPs, and commitment and dispatch projections for the resource will be made accordingly. Because these 10-minute reserve products have not

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[238] 2022 CONE Report at 52.

[239] Brattle EAS Aff. ¶ 56.

[240] Brattle EAS Aff. ¶ 56.

[241] Brattle EAS Aff. ¶ 30.

[242] Brattle EAS Aff. ¶ 30.

[243] Brattle EAS Aff. ¶ 58.

[244] Brattle EAS Aff. ¶ 55.

[245] *See* proposed Tariff, Attachment DD, section 5.10(a)(v-1)(D).

previously been procured day-ahead, but will be procured day-ahead and in real-time under the reserve market reforms beginning on October 1, 2022, PJM will use the historic real-time Synchronized and Non-Synchronized Reserve RTO prices for simulated real-time reserve dispatch as a proxy for the unavailable historical day-ahead prices in the simulated day-ahead reserve dispatch. In other words, under PJM's new dispatch approach, it will determine revenues associated with Synchronized and Non-Synchronized Reserve on both day-ahead and real-time bases.

In Docket No. EL19-58, PJM proposed this approach for Regulation service, and the Commission found that to be just and reasonable.[246] Before, PJM hesitated to apply this approach of scaling historical reserve prices by forward energy prices for estimating Synchronized and Non-synchronized Reserves revenues because the forward markets, at the time of PJM's August 2020 compliance filing, did not appear to have accounted for the Synchronized and Non-synchronized Reserves market changes the Commission initially approved in Docket No. EL19-58.[247] The Commission agreed, finding "merit" in PJM's hesitancy and as using forward prices before markets pricing in the energy market changes could "lead to inaccurate reserve revenue estimates because the relationship between energy and reserve prices will likely change once the instant reserve market reforms are implemented."[248]

For Secondary Reserve, at this time, PJM is proposing to set the clearing price for Secondary Reserves to $0.00/MWh for both the day-ahead and real-time dispatch simulations. This is grounded in the fact that PJM's simulations submitted in Docket No. EL19-58 showed very low prices for Secondary Reserve ($0.00/MWh once rounded to the nearest penny),[249] and therefore, the product would not materially affect resources' net EAS revenues. Accordingly, PJM's approach for Secondary Reserves is reasonable.

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[246] *See* EL19-58 Forward EAS Compliance Order at P 169 ("[W]e find that PJM's proposal to limit its projection of forward prices to energy, which has liquid futures markets, and Regulation, which is unchanged by the instant proceeding, will result in a just and reasonable estimate of cumulative future energy and ancillary services revenues.").

[247] *See PJM Interconnection, L.L.C.*, Compliance Filing of PJM Interconnection, L.L.C., Docket No. EL19-58-003, at 24 (Aug. 5, 2020) ("While in the long-term, such an approach [of scale historic reserve market clearing prices by the ratio of the forward energy prices to the historic energy prices] may be suitable [for Synchronized and Non-synchronized Reserves], under the current set of forward energy prices, this would result in scaling *down* reserve market clearing prices by as much as 33 percent in some cases. Such an outcome would be contrary to the expected increase in ancillary services market revenues relative to their historic levels following implementation of the market reforms adopted in the May 21 Order [*PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153]. As a result, and in an effort to not introduce arbitrary bias into the new approach, PJM proposed to use unscaled, historic ancillary services market clearing prices for the initial implementation." (footnotes omitted)).

[248] EL19-58 Forward EAS Compliance Order, 173 FERC ¶ 61,134, at P 168.

[249] *See PJM Interconnection, L.L.C.*, Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket No. EL19-58-000, at 105 (Mar. 29, 2019) (citing *id.*, Attachment D (Affidavit of Adam Keech on Behalf of PJM Interconnection, L.L.C. ¶ 42, Table 4)).

PJM's approach in this filing provides a reasonable proxy for expected ancillary services revenues for the vast majority of resources, as it is expected that ancillary services will continue to only comprise a small fraction of a resource's annual revenues from PJM's EAS markets.

6. Replacing the Peak-Hour Dispatch Model with the Projected EAS Dispatch Model that Simulates Dispatch for All Hours in a Day with the Objective of Optimizing the Resource's Dispatch in Response to Input Prices.

Once the forward energy and fuel prices, and the ancillary services prices, have been developed, PJM will input those, along with the Reference Resource's operating parameters, into a dispatch model to determine an estimate of the resource's expected EAS revenues for the future Delivery Year. Through the dispatch model, PJM will "simulate the generation and settlement of resources against shaped, forward-looking day-ahead and real-time energy and [ancillary services] prices,"[250] thereby ensuring that "energy market design modifications [are] more readily incorporated into capacity market parameters and prices."[251] Brattle observes that "this is best done with an optimization model that, like PJM's actual market, puts each resource to its highest value use, recognizing each resource's capabilities, costs, and operating constraints."[252]

Accordingly, as part of the forward-looking EAS Offset approach, PJM is proposing to switch from using the Peak-Hour Dispatch market simulation to a "Projected EAS Dispatch" simulation. The Projected EAS Dispatch approach, like the existing Peak-Hour Dispatch, takes the input prices as given and treats each generator as a price-taker, assuming that the Reference Resource will run when the estimated forward LMP exceeds the cost of operating the resource, without consideration of supply/demand balancing. However, the Projected EAS Dispatch approach will simulate whether the Reference Resource will run in any hour of the day and for any "contiguous period(s)," in which the resource would generate at a profit,[253] whereas, the Peak-Hour Dispatch only simulates whether the Reference Resource may be dispatched into the day-ahead and real-time energy market in four independent, four-hour blocks (between hour ending 8:00 and hour ending 23:00) each day. Further, the Peak-Hour Dispatch model does not account for ancillary service commitment and dispatch, unlike the Projected EAS Dispatch approach, which co-optimizes a resource's commitment and dispatch between the EAS markets. Thus, Projected EAS Dispatch better simulates actual market outcomes and is more consistent with the resource's commercial expectations. As Brattle explains, PJM will

[250] Brattle EAS Aff. ¶ 39.

[251] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153, at P 320.

[252] Brattle EAS Aff. ¶ 39.

[253] Tariff, Definitions O-P-Q (definition of Projected EAS Dispatch).

employ "an industry-standard simulation model" that allows for "the same approach we often use in commercial applications."[254]

To implement the Projected EAS Dispatch, PJM will employ a simulation software that offers a broad range of capabilities for modeling and optimization of energy systems.[255] Because the purpose of the exercise is to determine a resource's expected revenues, PJM will set the software's objective function to optimize the EAS commitment and dispatch of the generator in order to maximize the resource's value (as measured by net profit) based on the input EAS and fuel prices discussed above, subject to the constraints of the generator parameters.[256] To do so, the model will compare an energy offer, composed of the resource's marginal costs and other costs associated with generating energy, including the cost for a complete start and shutdown cycle against the forward LMPs and ancillary service market clearing prices.[257]

The Projected EAS Dispatch will simulate commitment and dispatch for both the day-ahead and real-time EAS markets. Similar to the sequencing of the day-ahead and real-time markets, the model will first run a day-ahead commitment and dispatch against the input forward day-ahead EAS prices. A real-time commitment and dispatch against forward real-time EAS prices is then run where the model assumes the resource runs in real-time for the periods in which it was committed day-ahead, but adjusts the dispatch for such hours based on the forward real-time LMPs and ancillary service prices. The resource may also be committed and dispatched for additional hours beyond those for which it was committed day-ahead. The gross revenues from such dispatch are then calculated assuming all day-ahead committed MWh are paid the forward day-ahead energy or ancillary service market clearing prices, as appropriate, and that any deviations between the real-time dispatch and the day-ahead dispatch are settled at the forward real-time energy or ancillary service market clearing prices, as appropriate. The settlement includes make-whole payments such that total gross revenues cover resource's real-time costs.

Thus, the Projected EAS Dispatch will calculate revenues from the Reference Resource based on the optimal commitment and dispatch of the resource per the objectives of the PJM EAS markets, thus approximating actual resource behavior and reasonable commercial expectations.[258] To determine the "net" revenues that will comprise the EAS Offset, PJM subtracts the costs to generate (i.e., marginal, plus startup and shutdown costs)

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[254] Brattle EAS Aff. ¶ 39.

[255] *See* Brattle EAS Aff. ¶ 39.

[256] *See* Tariff, Definitions O-P-Q (definition of Projected EAS Dispatch).

[257] Tariff, Definitions O-P-Q (definition of Projected EAS Dispatch).

[258] To the extent the simulation produces the scenario in which the unit cannot recover its real-time generation cost for the day (e.g., real-time LMPs that are lower than the day-ahead LMPs on which the resource was committed), the model credits the resource with an "uplift" (or make-whole) payment equivalent to the difference between the real-time generation cost and the revenue from energy and ancillary services. As such uplift payments occur in the same manner in PJM's energy markets today, the Projected EAS Dispatch model is simply and reasonably approximating PJM's energy markets.

the energy MWh for the hourly intervals in which the resource is dispatched in the real-time model.

To further approximate actual resource operations and commercial expectations, PJM will adjust the net revenues yielded by the model to linearly scale down the revenues to account for the resource's expected maintenance and unplanned (i.e., Equivalent Demand Forced Outage Rate ("EFORd")) outages. PJM will also assume maintenance outages. For example, PJM will assume the CC Reference Resource takes a two-week maintenance outage during the shoulder month of October, when such resources often take scheduled outages.

The resulting simulated generation pattern and the corresponding revenues net of operating costs for each day of the Delivery Year yield the projected energy revenue portion of the EAS Offset for each Reference Resource. PJM performs this simulation with energy, ancillary services, and fuel prices shaped by historical data from each of the three full preceding calendar years, and then takes the average of the revenues yielded by the three simulations as the EAS Offset value for the resource.

During the instant periodic review stakeholder process, PJM reviewed the methodology for the Projected EAS Dispatch with comparisons to the Peak Hour Dispatch. Such review included simulations to inform discussion and provide indicative values for 2026/27 Delivery Year given the updated methodology and assumptions from the Quadrennial Review.[259]

7. Tariff Changes to Implement Forward-Looking EAS Offset Approach.

The Tariff provisions necessary to apply the forward-looking EAS Offset approach starting with the RPM Auctions for the 2026/2027 Delivery Year and subsequent Delivery Years are generally already set forth in Tariff, Attachment DD, section 5.10(v-1). That is, PJM's proposed forward-looking EAS Offset approach is, for the most part, already memorialized in the Tariff, but is currently applicable only to RPM Auctions for the "2022/2023 Delivery Year." Thus, to apply these rules starting with the 2026/2027 Delivery Year, PJM proposes to remove that 2022/2023 limitation in the section title and provide that this approach applies "for the 2026/2027 Delivery Year and subsequent Delivery Years."[260]

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[259] *See, e.g.*, MIC Special Session – Quadrennial Review, *Forward Net Energy & Ancillary Services Revenue Offset: Additional Data to Inform Matrix Discussions*, PJM Interconnection, L.L.C. (June 21, 2022), https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220621-special-session-quad/item-04a---forward-net-energy--ancillary-services-revenue-offset---additional-data-to-inform-matrix-discussion.ashx.

[260] Proposed Tariff, Attachment DD, section 5.10(a)(i).

However, as discussed, PJM is modifying a few aspects of the previously approved forward-looking approach, and therefore a handful of tariff revisions are required.

First, to reflect the change in the Reference Resource from a combustion turbine to a CC (as updated for 2026/2027 values), PJM is updating two inputs used in the Reference Resource's revenue simulation. Specifically, PJM is revising the variable operating and maintenance expense from $1.95/MWh to $2.10/MWh and removing the $/startup input.[261] These inputs are designed to reflect the resource recovering through the energy market variable operating and maintenance costs, including major maintenance costs.[262] In the 2022 CONE Report, Brattle determined the variable operating and maintenance costs, including major maintenance costs for each of the four CONE Areas, and PJM's proposed $2.10/MWh is the simple average of those four values.[263]

With regard to the removal of the startup cost, as Brattle explains in the 2022 CONE Report, the $/startup value is only applicable for combustion turbine resources because "CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs."[264] Accordingly, because PJM proposes a CC Reference Resource, the startup cost is not appropriate.

Second, PJM proposes to update the cost-based revenues for the provision of reactive service from $2,199/MW-year to $2,546/MW-year.[265] In support of this reactive services value, PJM relies on the Market Monitor's most recent State of the Market Report for PJM-January through June 2022.[266] At Table 10-67, the Market Monitor provides that the total settled reactive revenue requirement for a CC resource is $2,546/MW-year.[267] PJM believes this is a reasonable value and proposes to include it in the EAS Offset.

The only other Tariff revisions required to implement the forward-looking EAS Offset approach relate to the determination of revenues from Synchronized Reserve, Non-synchronized Reserve, and Regulation. As discussed, PJM proposes to, at this time, omit Regulation from the forward-looking EAS Offset approach, and PJM is accordingly deleting the tariff provision associated with determining revenues associated with

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[261] *See* proposed Tariff, Attachment DD, section 5.10(v-1)(A).

[262] *See* 2022 CONE Report at 37 ("we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.").

[263] 2022 CONE Report at 34. The variable O&M costs for the CONE Areas are: $2.08/MWh (EMAAC); $2.07/MWh (SWMAAC); $2.12/MWh (Rest of RTO); and $2.14/MWh (WMAAC). *Id.*

[264] 2022 CONE Report at 62.

[265] *See* proposed Tariff, Attachment DD, section 5.10(v-1)(A).

[266] *State of the Market Report for PJM*, Monitoring Analytics, LLC (Aug. 11, 2022), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm.pdf.

[267] *Id*. at 603, Table 10-67.

Regulation.[268] With regard to Synchronized Reserve and Non-synchronized Reserve, PJM is replacing the prior approach for determining these reserve prices with the approach (and verbiage) the Commission had accepted for Regulation. Thus, the Tariff provides that the applicable estimate clearing price for these reserve products would be determined by multiplying the historical real-time hourly price "for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year."[269]

With these changes, the EAS Offset for the CC Reference Resource will be determined using forward-looking prices and a dispatch model that more closely approximates market behavior and commercial expectations.

E. All Changes Proposed in this Filing Are to Be Effective Starting with the 2026/2027 Delivery Year and Will Not Disturb the 2023/2024, 2024/2025, and 2025/2026 Delivery Years.

As discussed, PJM is proposing to implement all the changes proposed in this filing starting with the 2026/2027 Delivery Year and for all subsequent Delivery Years. The current-effective Tariff rules related to the VRR Curve shape, adjustment of Gross CONE values, determination of Net CONE, and the net EAS revenue offset will all remain in effect through the end of the 2025/2026 Delivery Year, and will govern issues related to Delivery Years prior to the 2026/2027 Delivery Year, including any Incremental Auctions conducted for Delivery Years prior to the 2026/2027 Delivery Year. Thus, the VRR Curves, Gross CONE values, net EAS revenue offsets, Net CONEs, and all other inputs and parameters determined for the 2023/2024, 2024/2025, and 2025/2026 Delivery Years will continue in effect for the respective Delivery Years. The Tariff revisions PJM is proposing clearly specify this delineation and state that the changes proposed in this filing apply only beginning with the 2026/2027 Delivery Year and all subsequent Delivery Years.

Implementing the changes proposed in this filing starting with the 2026/2027 Delivery Year is just and reasonable, as the data and support underlying the proposed changes are "based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis"[270] starting with the 2026/2027 Delivery Year. Indeed, the 2022 CONE Report and the VRR Curve specifically evaluate for the 2026/2027 Delivery Year.[271] Finally, implementation of these changes beginning with the 2026/2027 Delivery Year ensures sufficient notice and certainty to Market Participants of the updated auction parameters.

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[268] *See* proposed Tariff, Attachment DD, sections 5.10(a)(v-1)(D)(1) & (D)(4).

[269] *See* proposed Tariff, Attachment DD, sections 5.10(a)(v-1)(D)(1) & (D)(2).

[270] Tariff, Attachment DD, section 5.10(a)(iii) (detailing the requirements for the quadrennial review).

[271] The 2022 CONE Report is actually titled "PJM CONE 2026/2027 Report."

III. EFFECTIVE DATE

PJM requests an effective date of December 1, 2022, which is 62 days from the date of filing.

IV. CORRESPONDENCE

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

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V. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;

2. Revisions to the PJM Tariff (in redlined and non-redlined format (as Attachments A and B, respectively) and in electronic tariff filing format as required by Order No. 714);

3. Affidavit of Kathleen Spees and Samuel A. Newell on Behalf of PJM Interconnection, L.L.C. (with the 2022 VRR Curve Study included as Exhibit No. 2) (VRR Curve Affidavit), as Attachment C;

4. Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. (with the 2022 CONE Report included as Exhibit No. 2) (Brattle/S&L CONE Affidavit) as Attachment D;

5. Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C. (Brattle EAS Affidavit), as Attachment E; and

6. Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C. (ATWACC Affidavit), as Attachment F.

VI. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[272] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region[273] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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

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

VII. CONCLUSION

Accordingly, PJM requests that the Commission accept the enclosed Tariff revisions effective December 1, 2022.

Respectfully submitted,

/s/ Ryan J. Collins

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September 30, 2022

Attachment A

Revisions to the
PJM Open Access Transmission Tariff

(Marked/Redline Format)

Definitions – R - S

Ramping Capability:

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

“Real-time System Energy Price” shall mean the System Energy Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

For Delivery Years up to and including the 2025/2026 Delivery Year, "Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology ~~all CONE Areas~~, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh. For the 2026/2027 Delivery Year and subsequent Delivery Years, "Reference Resource" shall mean a combined cycle generating station, configured with a double train 1x1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine with evaporative cooling, Selective Catalytic Reduction technology and carbon monoxide catalyst, with firm gas transportation, and a heat rate of 6.604 MMbtu/MWh (with duct firing) and 6.369 MMbtu/MWh (without duct firing).

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

“Regulation Zone” shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

“Reliability Assurance Agreement” or “PJM Reliability Assurance Agreement” shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

“Reliability Pricing Model Auction” or “RPM Auction” shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

“Regional Transmission Enhancements” shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B (“Appendix B Agreement”) designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Reserve:

"Secondary Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates**.**

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

“Short-term Project” shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

“Site” shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

“Small Commercial Customer,” as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a “small commercial customer” under the terms of the applicable RERRA’s program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

"Start-Up Costs" shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in the storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- ~~For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:~~

  - ~~For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)], and for Delivery Years~~

~~through May 31, 2018, minus the Short-Term Resource Procurement Target;~~

- ~~For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target; and~~

- ~~For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target;~~

- ~~For the 2018/2019 Delivery Year and subsequent Delivery Years through and including the Delivery Year commencing June 1, 2021, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:~~

  - ~~For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 0.2%) divided by (100% plus IRM%)];~~

  - ~~For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)]; and~~

  - ~~For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)].~~

- For the 2022/2023 Delivery Year through and including ~~subsequent~~ the Delivery Year~~s~~ commencing June 1, 2025, the Variable Resource

Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

- For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 1.2%) divided by (100% plus IRM%)];

- For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1.9%) divided by (100% plus IRM%)]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 7.8%) divided by (100% plus IRM%)].

- For the 2026/2027 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions~~ for the 2019/2020, 2020/2021, and 2021/2022 Delivery Years~~, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the

Base Residual Auction for ~~such~~ each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022~~, and continuing thereafter unless and until changed pursuant to subsection (B) below~~ through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	108,000
BGE, PEPCO ("CONE Area 2")	109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3")	105,500
PPL, MetEd, Penelec ("CONE Area 4")	105,500

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

C) For the 2026/2027 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year (ICAP)**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	198,200
BGE, PEPCO ("CONE Area 2")	193,100
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3")	197,800
PPL, MetEd, Penelec ("CONE Area 4")	199,700

(1) Beginning with the 2027/2028 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:

(a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.

(b) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(c) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset ~~up to the 2021/2022 Delivery Year and~~ for 2023/2024 Delivery Year through and ~~subsequent~~including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the ~~2022~~2026/~~2023~~ 2027 Delivery Year and subsequent Delivery Years:

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (1) the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable

Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of $~~1.95~~2.10 per MWh~~ and $11,732/start~~, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis; plus (2) reactive service revenues of $2,~~199~~546 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceeding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.

C) "Forward Hourly LMPs" shall be determined as follows:

(1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.

(2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading days as of 180 days prior to the Base Residual Auction. For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

(3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the

Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;

(4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;

(5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such monthly on-peak or off-peak period. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

(6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference

between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and

(7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.

D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve~~,~~ and Secondary Reserve ~~and Regulation~~ and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:

(1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year~~the forward day-ahead and real-time market clearing prices for the Reserve Zone for each hour of the Delivery Year shall be equal to the historical real-time Synchronized Reserve Market Clearing Price for the Reserve Zone for the corresponding hour of the year.~~;

(2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and~~the forward day-ahead and real-time market clearing prices for the Reserve Zone for each hour of the Delivery Year shall be equal to the historical real-time~~

~~Non-Synchronized Reserve Market Clearing Price for the Reserve Zone for the corresponding hour of the year.~~

(3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be $0.00/MWh for all hours.

~~(4) For Regulation, the forward real-time Regulation market clearing price shall be calculated by multiplying the historical real-time hourly Regulation market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and~~

E) Forward Daily Natural Gas Prices shall be determined as follows:

(1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;

(2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;

(3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over the most recent thirty trading days as of 180 days prior to the Base Residual Auction;

(4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;

(5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar

years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Attachment B

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

Definitions – R - S

Ramping Capability:

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

“Real-time System Energy Price” shall mean the System Energy Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

For Delivery Years up to and including the 2025/2026 Delivery Year, "Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh. For the 2026/2027 Delivery Year and subsequent Delivery Years, "Reference Resource" shall mean a combined cycle generating station, configured with a double train 1x1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine with evaporative cooling, Selective Catalytic Reduction technology and carbon monoxide catalyst, with firm gas transportation, and a heat rate of 6.604 MMbtu/MWh (with duct firing) and 6.369 MMbtu/MWh (without duct firing).

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Reserve:

"Secondary Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates**.**

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

“Short-term Project” shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:

“Short-Term Resource Procurement Target” shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

“Site” shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

“Small Commercial Customer,” as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a “small commercial customer” under the terms of the applicable RERRA’s program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:

"Start-Up Costs" shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in the storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- For the 2022/2023 Delivery Year through and including the Delivery Year commencing June 1, 2025, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 1.2%) divided by (100% plus IRM%)];

- For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1.9%) divided by (100% plus IRM%)]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 7.8%) divided by (100% plus IRM%)].

- For the 2026/2027 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022 through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	108,000
BGE, PEPCO (“CONE Area 2”)	109,700
AEP, Dayton, ComEd, APS, DQL,	105,500

ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	
PPL, MetEd, Penelec (“CONE Area 4”)	105,500

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

C) For the 2026/2027 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	198,200
BGE, PEPCO (“CONE Area 2”)	193,100
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	197,800
PPL, MetEd, Penelec (“CONE Area 4”)	199,700

(1) Beginning with the 2027/2028 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:

(a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.

(b) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(c) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset for 2023/2024 Delivery Year through and including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the 2026/2027 Delivery Year and subsequent Delivery Years:

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (1) the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of $2.10 per MWh, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis; plus (2) reactive service revenues of $2,546 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward

Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceeding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.

C) "Forward Hourly LMPs" shall be determined as follows:

(1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.

(2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading days as of 180 days prior to the Base Residual Auction. For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

(3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;

(4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the

ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;

(5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such monthly on-peak or off-peak period. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

(6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and

(7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.

D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:

(1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year;

(2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and

(3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be $0.00/MWh for all hours.

E) Forward Daily Natural Gas Prices shall be determined as follows:

(1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;

(2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;

(3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over the most recent thirty trading days as of 180 days prior to the Base Residual Auction;

(4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;

(5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the

conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) above to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Attachment C

Affidavit of Kathleen Spees and Samuel A. Newell

UNITED STATES OF AMERICA
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. REGARDING PERIODIC REVIEW OF VARIABLE RESOURCE REQUIREMENT CURVE SHAPE AND KEY PARAMETERS

1. Our names are Dr. Kathleen Spees and Dr. Samuel A. Newell. We are employed by The Brattle Group as Principals. We submit this affidavit on behalf of PJM Interconnection, L.L.C. (PJM). Our qualifications as experts derive from our extensive experience evaluating capacity markets and related market design questions for system operators across North America and internationally. This experience has given us a broad perspective on the practical implications of capacity market design rules under a range of different economic and policy conditions.[1]

2. A subset of our market design work has focused on the development and improvement of capacity market demand curves oriented around differing design objectives. Our capacity demand curve design experience includes: (1) prior independent assessments in 2008, 2011, 2014, and 2018 of the PJM Variable Resource Requirement (VRR) Curve parameters and performance within its capacity market, the Reliability Pricing Model (RPM); (2) support of the New England Independent System Operator to develop a sloping demand curve for use in its Forward Capacity Market; (3) support of the Midcontinent Independent System Operator to develop a demand curve for its formerly-proposed Competitive Retail Solution; (4) support of the Alberta Electricity System Operator to develop a capacity market demand curve for its formerly-proposed capacity market; (5) support for the Singapore Energy Market Authority to develop a demand curve for its proposed Forward Capacity Market; and (6) support for the Ontario Independent Electricity System Operator to develop a demand curve for its two-season capacity market.[2]

3. Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She earned a PhD in Engineering and Public Policy, an MS in Electrical and Computer Engineering from Carnegie Mellon University, and a BS in Mechanical Engineering and Physics from Iowa State University. Dr. Newell is an economist and engineer with 24 years of experience analyzing and modeling electricity

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[1] We have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM, New England, New York, Ontario, Alberta, California, Texas, Midcontinent, Italy, Russia, Greece, Singapore, and Australia.

[2] See our four independent reviews of PJM's capacity market and associated design parameters published in 2008, 2011, 2014, and 2018. The most recent of these is: Samuel A. Newell, David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, J. Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin, *Fourth Review of PJM's Variable Resource Requirement Curve*, prepared for PJM Interconnection, L.L.C., April 19, 2018.

wholesale markets, the transmission system, and wholesale electricity market design. He earned a PhD in Technology Management and Policy from the Massachusetts Institute of Technology, an MS in Materials Science and Engineering from Stanford University, and a BA in Chemistry and Physics from Harvard College.

OUR INDEPENDENT REVIEW OF THE VARIABLE RESOURCE REQUIREMENT CURVE

4. In July 2021, PJM retained Brattle to conduct an independent review and performance assessment of its VRR Curve and parameters, as required periodically under PJM's Open Access Transmission Tariff. The results of our independent review of the VRR Curve parameters are summarized here and described in the attached complete report *Fifth Review of PJM's Variable Resource Requirement Curve: For Planning Years Beginning 2026/27* (2022 VRR Curve Report).[3] The results of Brattle's independent review of the Gross Cost of New Entry (Gross CONE, or CONE), energy and ancillary services (EAS) offset, and Net Cost of New Entry (Net CONE) are set forth in separate reports and affidavits filed concurrently with this affidavit.

5. Our 2022 VRR Curve Report develops recommendations to improve the performance of the VRR Curve, along with related recommendations to improve RPM more broadly. With respect to the VRR Curve, we recommend updating the price and quantity points as summarized in the Table 1 and Figure 1. As discussed below, the resulting curve is similar to the current one, but steeper, with the left-most part of the curve (Point A) at the same quantity, re-expressed in Unforced Capacity (UCAP) terms instead of Installed Capacity (ICAP) terms. The price points are still indexed to Net CONE (now with a combined cycle (CC) rather than combustion turbine (CT) plant as the Reference Resource), but with the cap set higher in the event that 1.75 × Net CONE exceeds Gross CONE.

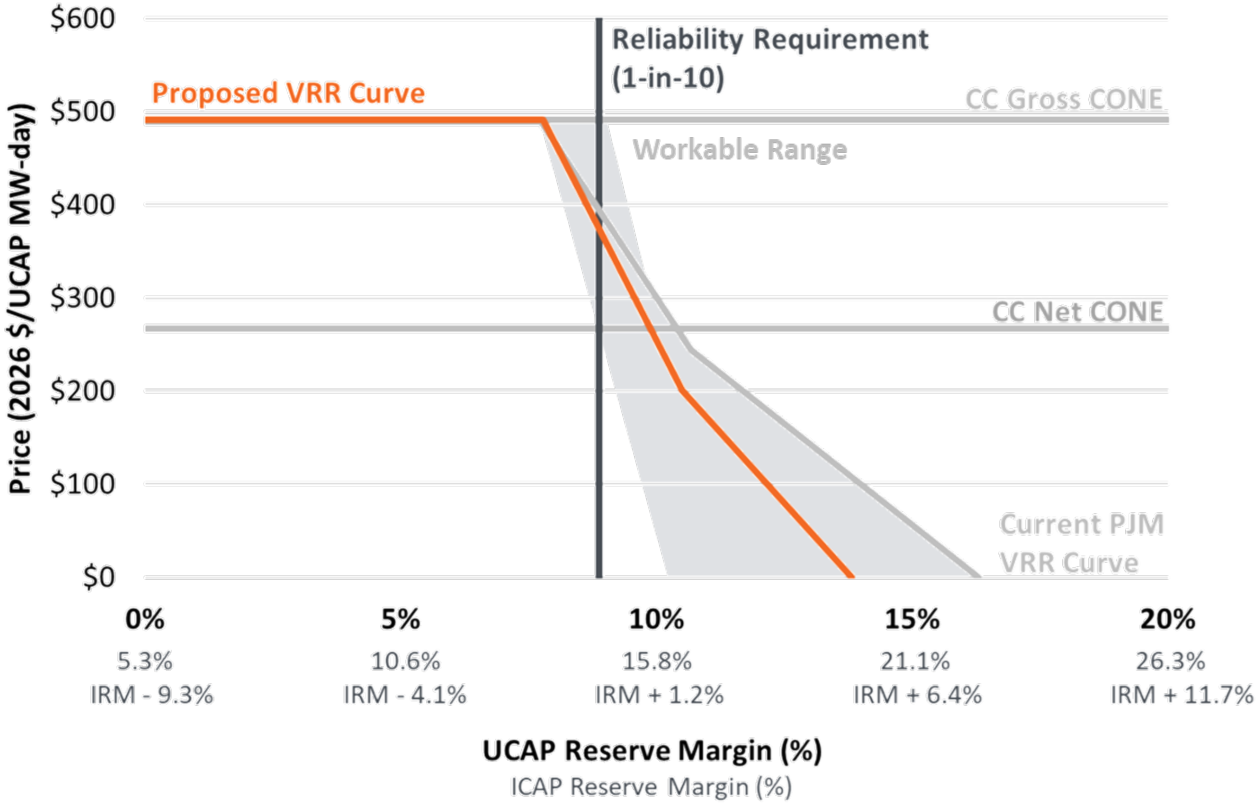
Table 1: Current and Proposed VRR Curve Formulas

Point	Current VRR Curve Formula	Proposed VRR Curve Formula
Point A *the cap*	**Price:** Max{CONE, 1.5 × Net CONE} **Quantity:** (1 + IRM − 1.2%) ÷ (1 + IRM) × Reliability Requirement	**Price:** Max{CONE, 1.75 × Net CONE} **Quantity:** 99.0% × Reliability Requirement
Point B *the kink*	**Price:** 0.75 × Net CONE **Quantity:** (1 + IRM + 1.9%) ÷ (1 + IRM) × Reliability Requirement	**Price:** 0.75 × Net CONE **Quantity:** 101.5% × Reliability Requirement
Point C *the foot*	**Price:** $0 **Quantity:** (1 + IRM + 7.8%) ÷ (1 + IRM) × Reliability Requirement	**Price:** $0 **Quantity:** 104.5% × Reliability Requirement

Note: IRM = Installed Reserve Margin

[3] See Kathleen Spees, Samuel Newell, Andrew Thompson, Xander Bartone. *Fifth Review of PJM's Variable Resource Requirement Curve: For Planning Years Beginning 2026/27,* prepared for PJM Interconnection LLC., April 19, 2022, attached hereto as Exhibit 2.

Figure 1: Current and Proposed Variable Resource Requirement Curves



Notes: Though visually indistinguishable in this chart, the price caps on the two curves are not identical; the current VRR curve price cap is represented as $489/MW-day in this chart (based on 1.5 × Net CONE for a gas CT), while the proposed curve price cap is represented as $491/MW-day (based on 1 × Gross CONE for a gas CC). The parameters illustrated here are consistent with an initial draft of our 2022 CONE Study and do not reflect the more recent updates included in the current filing, with RTO Gross CONE updated to be $558/MW-day UCAP and indicative RTO Net CONE estimated to be $264/MW-day UCAP (similar to the $267/MW-day used in the VRR simulations). Prior to each future RPM auction, PJM will update its calculations of the EAS offset, CONE, and Net CONE parameters. Our assessment of VRR Curve performance should remain valid even as Net CONE is updated given that our analysis is not particularly sensitive to changes in Net CONE, as long as the administrative estimate accurately represents the true Net CONE faced by market participants.

6. We arrived at this recommended VRR Curve formula through an iterative approach involving input from stakeholders, qualitative analysis, and probabilistic simulations under base case and stress conditions.

GUIDING THEMES FROM PJM BOARD OF MANAGERS, STAKEHOLDER INPUT, AND PRESENT CONTEXT OF NET CONE UNCERTAINTY

7. We conducted this Quadrennial Review with a particular focus on three areas identified as a priority by PJM's Board of Managers and stakeholders: (1) ensuring appropriate levels of procurement, given that past auctions have procured capacity beyond the reliability target; (2) uncertainties in Net CONE, and accounting for the larger uncertainties in Net CONE as compared to past reviews; and (3) a changing resource mix in PJM and impacts of potential reforms.

8. Our initial discussions with stakeholders confirmed that the overarching objectives for the VRR Curve remained the same: in short, 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.

9. Our 2022 VRR Curve Report describes our analysis of causes of past excess capacity. Our analysis indicated that the single largest factor has been the load forecast, which PJM has been addressing on a separate track. We also determined that the VRR Curve shape has contributed to excess capacity, meaning that a steeper VRR Curve could be used to mitigate over-procurement as long as the resulting reliability levels would not fall below the 1-event-in-ten-years (1-in-10) or 0.1 Loss of Load Event (LOLE) reliability standard.

10. Regarding Net CONE uncertainty, stakeholders emphasized that the industry's transition to clean energy is creating change and uncertainty affecting Net CONE. Since then, the uncertainty has been compounded by inflation and Russia's invasion of Ukraine, both of which are currently affecting Net CONE even more profoundly. We will address these issues in reverse order here.

11. World natural gas shortages caused by Russia's invasion in February 2022 are elevating and destabilizing gas and power prices more than any time since 2008. This directly impacts Net CONE and its uncertainty: for example, PJM's forward-looking estimate of CC EAS offsets has increased over the course of this study by $84/MW-day (UCAP) for the RTO, reflecting changes in forward prices as of April 2022 compared to July 2021.[4] This reduces Net CONE by about 24%.[5] If such shifts occur again between the time when PJM sets auction parameters and the auction, the administrative value of Net CONE could similarly differ from capacity suppliers' expectations at the time of the auction. Market conditions could change between the auction and the delivery year, the prospect of which will affect suppliers' views in ways that may be difficult for PJM to estimate. Thus PJM risks over-estimating (or under-estimating) Net CONE more substantially than in the past, a consideration that informed our recommendation to implement a higher price cap in certain circumstances (as discussed further below).

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[4] Natalie Tacka, *Forward Net Energy & Ancillary Services Revenue Offset Methods & Comparisons*, PJM Interconnection, L.L.C. (May 20, 2022), https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220520-special-session/item-03---forward-net-energy--ancillary-services-revenue-offset-methods--comparisons---post-meeting.ashx (showing $286/MW-Day for the RTO). We have confirmed with PJM that the units are in 2026 dollars per MW-Day in ICAP terms using forward prices from April 2022, and that the $286/MW-Day included $9.18/MW-Day of Net Reactive Service Revenue. Since then, PJM has decided to assume Net Reactive Service Revenues of only $6.98/MW-Day, so the most updated EAS offset becomes $284/MW-Day (ICAP) in 2026 dollars. We translate this to $293/MW-Day (UCAP), by dividing by CC (13.1% EFORd) (with EFORd taken from PJM's May presentation). Compared to $209/MW-Day (UCAP) presented in Table 20 of the 2022 CONE Study based on forward prices from July 2021, that increase is $84/MW-Day (UCAP) higher in 2026 dollars.

[5] Net CONE = CONE – EA&S Offset, where updated CONE = 558/MW-Day (UCAP) from our concurrent CONE affidavit, and the EAS offset with all updates becomes $293/MW-Day (UCAP) as described in the footnote above; all figures are in 2026 dollars.

12. CONE itself is also more uncertain than in prior reviews due to supply chain shortages and associated inflation that is higher and more volatile than any time in the past 40 years. Over the course of this Quadrennial Review, the Blue Chip Economic Indicators' implied Consumer Price Index (CPI) forecast for 2026 has increased by 8% and continues to change rapidly.[6] Almost a third of that change occurred since April when we completed our CONE Study. With that and related changes in the cost of capital our estimate of CONE increased by 8% since April, which increases Net CONE by 19%.[7] This uncertainty further contributed to our recommendation to consider a steeper curve with a higher cap.

13. Meanwhile, the industry's transition to clean energy presents greater uncertainties than in prior Quadrennial Reviews. Policies in several states mandate the rapid reduction, replacement, and/or eventual elimination of fossil generation (*e.g.*, policies of New Jersey, Illinois, Virginia, Maryland, and District of Columbia). Other states have not adopted clean energy mandates, but they too are affected by the rapid cost declines (until recently) of wind, solar, and storage; and federal policies supporting these clean technologies. For example, the Inflation Reduction Act passed just in September provides substantially extended and expanded tax credits for solar, wind, storage, and hybrid technologies. With all of these changes, the composition of the fleet and market/regulatory conditions in 10–20 years will differ markedly from today, in ways that are difficult to predict.

14. These long-term uncertainties drive Net CONE uncertainty through their effect on current entrants' long-term energy and capacity revenues expectations, and thus their actual Net CONE—their reservation price for entering the market, theoretically given by the capacity revenue they would need in year 1 in order to just earn their market return on and of capital over their economic life (given expectations of future costs and revenues). We must therefore be humble about our ability to accurately assess Net CONE and should modify the design of the VRR curve to be steeper with a higher cap in order to be confident that the auction will still clear near the target quantity.

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6 See "Blue Chip Economic Indicators – Top Analysts' Forecasts of the US Economic Outlook for the Year Ahead Vol. 46, No. 6. Wolters Kluwer. June 11th, 2021." and "Blue Chip Economic Indicators – Top Analysts' Forecasts of the US Economic Outlook for the Year Ahead Vol. 47, No. 9. Wolters Kluwer. September 12th, 2022." We projected the CPI in the 2nd quarter of 2026 using data from both the June 2021 edition and the September 2022 edition. In the case of the June 2021 edition, we use the CPI from its latest forecast (Q4 2022) and inflate the CPI by the estimated long-run inflation rate for 2023 to 2027 (2.3%) to obtain the estimated CPI in Q2 2026. We repeat this process for the September 2022 edition, using the forecasted CPI as of Q4 2023 and inflating this CPI by the estimated long-run inflation rate for 2024 to 2028 (2.2%) to obtain the estimated CPI in Q2 2026. We then compare these two forecasted CPIs to derive the change in the implied CPI.

7 With the updated EAS offset of $293/MW-day UCAP and updated CONE of $558/MW-day, Net CONE is $264/MW-day, which is 19% more than Net CONE based on the same EAS offset and CONE of $516/MW-day from the 2022 CONE Study.

FINDINGS OF OUR VRR CURVE ANALYSIS

15. Through this assessment we identified an approximate "workable range" of alternative VRR Curves (gray area in Figure 1) and evaluated several alternative VRR curve shapes relative to identified design objectives and performance metrics.[8]

16. Within this workable range, several alternative VRR Curves could offer acceptable performance across the defined design objectives, but with trade-offs among competing priorities. Steeper VRR curves offer improved certainty in quantity, but at the cost of higher price volatility, a trade-off that made sense under current conditions, as discussed below.

17. Though both the current and proposed VRR Curves are within the identified workable range and offer a different balance among competing objectives, we recommend the proposed curve as offering stronger overall performance as discussed in brief here and in more detail in the attached 2022 VRR Curve Report. Table 2 compares the performance of the current curve and the proposed curve, each under a range of assumptions: (a) a base assumption (blue shaded rows), in which the true Net CONE matches the administrative estimate of Net CONE for a Combined Cycle (CC) plant; and (b) under three sensitivity case assumptions in which the true Net CONE is lower or higher than the administrative CC-based estimate.

Table 2: Performance of the Current vs. Proposed VRR Curve Under Base Scenario (Accurate Net CONE) and Uncertainty Scenarios (Net CONE Over- or Under-Estimate)

	Price			Reliability					Cost
	Average *($/MW-d)*	Standard Deviation *($/MW-d)*	Frequency at Cap *(%)*	Average LOLE *(events/yr)*	Average Excess (Deficit) *(MW)*	Average Excess (Deficit) *(IRM + X %)*	Frequency Below Target *(%)*	Frequency Below IRM - 1% *(%)*	Average Procurement Cost *($ mln/yr)*
Current Curve									
True Net CONE = 0.6 × CC	$160	$52	0.0%	0.026	4548	4.0%	0.0%	0.0%	$8,029
True Net CONE = CC	**$267**	**$74**	**1.5%**	**0.059**	**2026**	**1.8%**	**7.5%**	**2.0%**	**$13,169**
True Net CONE = CT	$326	$86	7.8%	0.085	922	0.8%	23.2%	9.0%	$15,941
True Net CONE = 1.4 × CC	$374	$87	17.9%	0.117	(25)	0.0%	43.2%	20.0%	$18,133
Proposed Curve									
True Net CONE = 0.6 × CC	$160	$57	0.0%	0.043	2861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 × CC	$374	$94	21.2%	0.128	(393)	(0.3%)	50.0%	24.8%	$18,092

Notes: All quantities in 2026$/UCAP MW-day. Parameters: CC Gross CONE = $491, CC Net CONE = $267, 1.5 × Net CONE = $401, 1.75 × Net CONE = $467.

RATIONALE FOR CHANGE TO UNFORCED CAPACITY-BASED QUANTITIES

18. The quantity points in the proposed VRR Curve would be calculated using a simpler calculation in the units of UCAP that are used to define all sold, procured, and committed volumes in the PJM capacity market. This adjustment removes the need for a unit conversion

8 See 2022 VRR Curve Report, in particular Sections I and III, Subsection III.E, and Appendices E-F.

that is embedded within the formulas of the current VRR Curve to convert from units of Installed Reserve Margin (IRM) and ICAP MW. The proposed UCAP-based formulas would be slightly more stable across years and improve consistency with the RPM design.

RATIONALE FOR STEEPER VRR CURVE SHAPE WITH HIGHER PRICE CAP

19. Compared to the current VRR Curve, the proposed VRR Curve is somewhat steeper, with Point A in nearly the same location but with Points B and C left-shifted by approximately 0.1% and 2.2% of the Reliability Requirement respectively.[9] This shift to a somewhat steeper VRR curve is appropriate under present market conditions with high uncertainty in the Net CONE estimate and rapid turnover in the capacity fleet, due to environmental policies, rapid technological change, and the retirement of aging plants. This uncertainty makes it more difficult to set VRR Curve prices such that the market clears near the target reserve margin. Both Net CONE uncertainties and rapid fleet turnover increase the likelihood of the RPM producing either excess procurement (and associated costs) or under-procurement (and associated reliability challenges). Adopting a somewhat steeper proposed VRR Curve will mitigate these challenges by reducing quantity uncertainty.

20. The specifics of the proposed steeper curve focus on mitigating the potential for over-procurement. By reducing the quantity in the B-to-C or "foot" region, the proposed VRR Curve will reduce the capacity market's susceptibility to over-procurement, particularly in long market conditions. We estimate that the proposed curve will procure approximately 805 MW less capacity on average under long-run equilibrium conditions, assuming that the CC-based Net CONE is accurately estimated (compare blue shaded rows of Table 2 above). If the administrative Net CONE were persistently over-estimated, the proposed curve would further limit over-procurement by up to approximately 1,687 MW under long-run equilibrium conditions. The role of a steeper curve to limit over-procurement would be even larger when the capacity market experiences transient periods of excess supply. Susceptibility to over-procurement will be further mitigated by adopting a gas CC plant as the Reference Resource to more accurately reflect the true Net CONE faced by developers. This reduction to procurement volumes will result in lower costs to society and to consumers on average and in surplus capacity conditions.

21. The steeper proposed demand curve comes at the cost of somewhat reduced, but still acceptable, performance in the dimensions of reliability and price volatility. We estimate that reliability will worsen from 0.059 Loss of Load Events (LOLE) with the current curve to 0.073 LOLE with the proposed curve. This expected reliability level still exceeds PJM's reliability standard of one day in ten years (1-in-10), or 0.1 LOLE. Further, because the proposed curve maintains the price and quantity of Point A in approximately the same location as that of the current curve, it offers substantial protections against the potential for very low reliability events. We estimate the frequency of market procurement outcomes more than 1% below the installed reserve margin (IRM) to be 3.3% for the current curve and 3.9% for the

[9] This difference in quantity points is calculated assuming a 16% installed reserve margin for illustrative purposes. If the installed reserve margin is lower, the difference between the quantity points in the current and proposed curves would be slightly greater (and vice versa).

proposed curve. Price volatility will also worsen somewhat with an increase of approximately \$11/MW-day standard deviation of year-to-year price volatility, a level in the mid-range compared to other curves we examined.[10]

22. Overall, the proposed steeper curve will offer a substantial improvement over the current curve with respect to the potential for over-procurement, commensurately reducing expected customer costs, while maintaining reliability in excess of the reliability standard and while producing a modest expected increase in price volatility.

RATIONALE FOR ADJUSTING THE FORMULA FOR THE PRICE AT POINT A

23. The proposed VRR Curve, like the current VRR Curve, will have a price at the maximum of either 1 × Gross CONE or a multiple of Net CONE. Given that we estimate the 1 × Gross CONE parameter to be greater than the proposed multiple of Net CONE, we do not expect this change to the VRR curve formula will result in different procurement quantities or prices under anticipated market conditions.

24. However, this adjustment will provide greater protection against low-reliability outcomes in years under different market conditions where energy and ancillary services offsets decrease and the 1.75 × Net CONE cap is binding. This protection against low reliability events most relevant if the administrative Net CONE parameter is under-estimated relative to the true Net CONE faced by developers, as summarized in the bottom two panels of Table 3 below (referencing the proposed VRR Curve with a 1.75 × Net CONE and an alternative VRR Curve with a 1.5 × Net CONE cap, respectively). In a sensitivity scenario in which the true Net CONE (consistent with a gas CT plant) is higher than administrative Net CONE, the proposed VRR Curve with cap at 1.75 × Net CONE will produce reliability at approximately 0.103 LOLE, or very near PJM's 1-in-10 reliability standard. Under the same scenario, an alternative curve with a lower price cap at 1.5 × Net CONE would produce poorer reliability at approximately 0.139 LOLE (1-in-7.2).

25. In a scenario with a larger under-estimate of Net CONE (true Net CONE 40% higher than administrative Net CONE), the higher price cap offers greater reliability protections. The proposed curve with a cap at 1.75 × Net CONE maintains reliability at 0.141 LOLE (1-in-7.2) while the lower cap at 1.5 × Net CONE would produce more degraded reliability at 0.251 LOLE (1-in-4).

26. The protective value of increasing the cap from 1.5 × to 1.75 × Net CONE is illustrated more prominently in the curves' performance in limiting the frequency of low reliability events more than 1% below IRM. Increasing the cap reduces the frequency of these events from 29% to 12% in the moderate Net CONE under-estimate scenario, or from 61% to 30% in the large Net CONE under-estimate scenario.

27. Thus, maintaining a high contingent price cap protects against low reliability events by ensuring that prices can become high enough to attract sufficient supplier interest to develop needed capacity supplies and produce prices at the true Net CONE on average, even if

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[10] See 2022 VRR Curve Report, Section E.

administrative Net CONE is underestimated. Given substantial uncertainties in Net CONE under current and anticipated market conditions both PJM-wide and in some locations, it is appropriate to place greater emphasis on the need to address potential scenarios of Net CONE under-estimation than we have in prior VRR Curve Reviews.

28. In summary, the proposed update from 1.5 × Net CONE to 1.75 × Net CONE cap is not likely to affect the VRR Curve performance under expected market conditions, with no impact if 1 × Gross CONE cap is the binding value. However, the update to the Net CONE multiplier will substantially improve reliability under a potential scenario where Net CONE is under-estimated and the Net-CONE-based cap is binding. It also helps compensate for the reliability effect of a slightly left-shifted market equilibrium from the proposed curve's prices diminishing more quickly to zero (as quantity increases) than the current curve.

Table 3: Performance of the Proposed VRR Curve (Price Cap at either 1 × CONE or 1.75 × Net CONE) Compared to an Alternative Curve (Price cap at 1.5 × Net CONE)

	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Proposed Curve, Cap at 1 × Gross CONE									
True Net CONE = 0.6 × CC	$160	$57	0.0%	0.043	2861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 × CC	$374	$94	21.2%	0.128	(393)	(0.3%)	50.0%	24.8%	$18,092
Proposed Curve, Cap at 1.75 × Net CONE									
True Net CONE = 0.6 × CC	$160	$57	0.0%	0.043	2851	2.5%	0.0%	0.0%	$7,938
True Net CONE = CC	**$267**	**$81**	**3.3%**	**0.076**	**1137**	**1.0%**	**13.6%**	**3.9%**	**$13,092**
True Net CONE = CT	$326	$88	11.6%	0.103	224	0.2%	36.3%	12.4%	$15,863
True Net CONE = 1.4 × CC	$374	$85	27.0%	0.141	(677)	(0.5%)	57.2%	30.4%	$18,045
Alternative Curve, Cap at 1.5 × Net CONE									
True Net CONE = 0.6 × CC	$160	$56	0.0%	0.044	2812	2.4%	0.0%	0.0%	$7,935
True Net CONE = CC	**$267**	**$69**	**7.2%**	**0.087**	**753**	**0.7%**	**24.0%**	**7.9%**	**$13,041**
True Net CONE = CT	$326	$67	26.9%	0.139	(604)	(0.5%)	55.3%	29.0%	$15,741
True Net CONE = 1.4 × CC	$374	$46	59.0%	0.251	(2498)	(2.1%)	85.3%	61.3%	$17,761

Notes: All quantities in 2026$/UCAP MW-day. Assumed parameters: CC Gross CONE = $491, CC Net CONE = $267, 1.5 × Net CONE = $401, 1.75 × Net CONE = $467. The formulas for points A, B, and C on the proposed and alternative curves are identical, except for the price at Point A.

Exhibit No. 1

Kathleen Spees and
Samuel A. Newell
Qualifications

KATHLEEN SPEES
Principal

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Dr. Kathleen Spees is a Principal and Board Member at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on:

- Wholesale Power Market Reform
- Carbon and Environmental Policy
- Capacity Market Design
- Wholesale Energy, Ancillary Service, and Specialized Products Market Design
- Generation and Transmission Asset Valuation
- Integration of Emerging Technologies

Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets. Her clients include electricity system operators in PJM, Midcontinent ISO, New England, Ontario, New York, Alberta, Texas, Italy, Singapore, and Australia. Electricity market design assignments involve ensuring adequacy of capacity and energy market investment incentives to achieve reliability objectives at least cost; designing carbon and environmental attribute markets and incentives to support efficient clean energy transition; modeling projected outcomes in electricity markets and multi-sector carbon markets; enhancing operational reliability and efficiency through energy market, scarcity pricing, and ancillary service market improvements; effectively integrating intermittent renewables, storage, demand response, and other emerging technologies; evaluating benefits and costs of industry reform initiatives; and enhancing efficiency at market interties.

For system operators and regulators, Dr. Spees provides expert support through stakeholder forums, independent public reports, and testimony in regulatory proceedings. For utilities and market participants, her assignments support business strategy, investment decisions, asset transactions, contract negotiation, regulatory proceedings, and litigation. Dr. Spees has developed and applied a wide range of analytical and modeling tools to inform these policy, market design, and business decisions.

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center in 2008 and her MS in Electrical and Computer Engineering from Carnegie Mellon University in 2007. She earned her BS in Physics and Mechanical Engineering from Iowa State University in 2005.

Publications posted at: http://www.brattle.com/experts/kathleen-spees

REPRESENTATIVE EXPERIENCE

WHOLESALE POWER MARKET REFORM

- **Ontario Market Renewal Benefits Case.** For the Ontario Independent Electricity System Operator (IESO), developed an analysis evaluating the benefits and implementation costs associated with fundamental reforms to wholesale power markets, including implementing nodal pricing, a day-ahead energy market, enhanced intra-day unit commitment, operability reforms, an enhanced intertie design, and a capacity market. Analysis included: (a) market visioning sessions with IESO staff and stakeholders to identify future market design requirements; (b) identify primary drivers and quantify system efficiency benefits; (c) review lessons learned from other markets' reforms to identify opportunities and reform risks; (d) conduct a bottom-up analysis of implementation costs for replacing market systems; and (e) evaluate interactions with existing supply contracts.

- **MISO Market Development Vision.** For the Midcontinent Independent System Operator (MISO), worked with staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **Australia NEM Electricity Market Vision for Enabling Innovation and Clean Energy.** On behalf of the Australian Energy Market Operator reviewed electricity market design options for the future of the NEM. Evaluated opportunities for relying on markets, innovation, and new technologies to address a range of challenges in the context of significant increases in customer costs, high gas prices, large clean energy penetration, coal retirements, uncertain carbon policies, and emerging reliability and security concerns.
- **Thailand Power Market Reform.** Supported market design options and recommendations for potential power market reforms in Thailand, including the introduction of forward, day-ahead, and real-time energy markets, as well as the potential introduction of a bilateral or centralized capacity market. Examined interactions with retail rates, existing contracts, and self-supply arrangements.
- **Power Market Reform to Accommodate Decarbonization and Clean Energy Policies.** For the system operator in a jurisdiction pursuing significant clean energy and decarbonization policies, assisted in evaluating market design alternatives. Estimated energy price, customer cost, and reliability implications under alternative energy, ancillary service, and capacity market design scenarios. Quantified implications of key uncertainties such as intermittent resource penetration levels and impacts of interties with external regions. Provided research and comparative analysis of design alternatives and lessons learned from other jurisdictions.
- **Western Australia Power Market Reform Options.** For EnerNOC, developed a whitepaper describing high-level market reform options in the face of escalating customer costs in Western Australia. Described the drivers of capacity payment costs in comparison to other major cost driver. Identified high-level options for pursuing capacity and energy-only market design reforms, comparing advantages and disadvantages.
- **Russian Capacity and Natural Gas Market Liberalization.** On behalf of a market participant, conducted an assessment of market design, regulatory uncertainty, and liberalization success.

Focus was on the efficiency of market design rules in the newly introduced system of capacity contracts combined with capacity payments, as well as on the impacts of gas price liberalization delays.

- **PJM Review of International Energy-Only, Capacity Market, and Capacity Payment Mechanisms.** For PJM Interconnection, conducted a review of energy-only markets, capacity payment systems, and capacity markets on behalf of PJM market operator. Reviewed reliability, volatility, and overall investment outcomes related to details of market designs in bilateral, centralized, and forward commitment markets.
- **Options for Reconciling Regulated Planning and Wholesale Power Markets in in MISO.** For NRG, developed a whitepaper assessing reliability and economic implications of current capacity market and integrated planning approaches, and the challenges in accommodating retail access and integrated planning within the same market region. Recommended options for enhancing the MISO capacity market and regulated entities' approaches to planning.
- **Review of California Planning and Market Mechanisms for Resource Adequacy.** For Calpine, evaluated interactions and implications of California's policy, planning, and market mechanisms affecting resource adequacy. Recommended improvements to reconcile inconsistencies and enhance efficiencies in regulated long-term procurements, short term local resource adequacy construct, and CAISO backstop mechanisms.

Carbon and Environmental Policy

- **Greenhouse Gas Cap-and-Trade Market Design and Modeling.** For the New York City Mayor's Office of Sustainability, conducted a study to develop market design options for a greenhouse gas cap-and-trade market under Local Law 97 that imposes 80% carbon reductions on large buildings in New York City by 2050. Utilized Brattle's Decarbonized Energy Economy Planning (DEEP) model to assess the outcomes of alternative market designs including cost, pricing, emissions, City revenues, distributional impacts, and implications on environmental justice communities.
- **Design of a Competitive Forward Clean Energy Market.** For NRG, developed a market design to attract investment in clean energy resources to serve state policy goals and customer demand for clean energy. Developed detailed design proposal for integrating and aligning the market with wholesale electricity markets and competitive retail markets. Supported drafting of state legislation and testimony before state legislature.
- **Integrating Markets and Public Policy in New England.** For a coalition of stakeholders, engaged in a collaborative effort to develop market-based approaches for accommodating and achieving state decarbonization objectives. Developed and refined design proposals including carbon pricing and market-based clean energy procurements, while identifying options for reducing regulatory uncertainties, avoiding cross subsidies across states, and mitigating customer cost impacts. Evaluated options for improving interactions with existing energy, capacity, renewable energy credit, and carbon markets. Conducted modeling of price, cost, and emissions outcomes under a range of designs. Engaged in an iterative process to develop, present, and

refine design proposals based on input from a broad array of stakeholders. Provided expert support in outreach to state policymakers and industry groups.

- **Ontario Market Evolution to Support a 90% Clean Energy System and Increasing Distributed Resources.** For the IESO, supported the activities of the non-emitting stakeholder committee to model market reforms necessary to fully enable the 90% clean energy fleet. Supported stakeholder workshops to identify potential futures with many more distributed resources, a range of technology costs, and a variety of market designs. Conducted modeling analysis to analyze market outcomes including cost, reliability, resource curtailment, and resource revenues.
- **Locational Marginal Emissions.** Co-authored a whitepaper with ReSurety proposing an approach to valuing clean energy, demand reductions, and storage relative to locational, 5-minute carbon abatement value. Descripted the next generation of renewable procurements, contract incentives, sustainability accounting, and renewable energy credits in alignment with carbon abatement value.
- **Advising on Federal Clean Energy Legislation (Multiple Clients).** Provided expert advice and language on the development of cost-effective clean energy legislation. Supported engagement with interest groups and legislative committee staff.
- **National Carbon Policy Design and Interactions with Power Markets.** For an international regulator, analyzed a range of options for the design of a carbon policy for the electricity sector, considering impacts on the wholesale electricity market and interactions with other sectors. Analyzed a range of alternatives for intensity-based and cap-and-trade based approaches, alternative allocations methods, and interactions with renewables standards. Developed two detailed design alternatives within the specified policy constraints.
- **Review of International Carbon Mechanisms.** For an RTO, conducted a survey of international carbon pricing, cap-and-trade, and rate-based mechanisms, and detailed review of design elements of the mechanisms implemented in Europe, California, Alberta, and the Regional Greenhouse Gas Initiative. Evaluated a range of alternatives for implementing the Clean Power Plan across states while effectively integrating with wholesale markets.
- **New York ISO Carbon Pricing.** For the New York ISO, examined economic implications of a possible carbon pricing proposal within the wholesale electricity market. Developed a whitepaper evaluating interactions with state environmental policies, wholesale power markets, intertie pricing, capacity market, and transmission planning. Estimated energy price and customer cost impacts.
- **Carbon Allowance Allocations Alternatives.** For the National Resources Defense Council, developed a whitepaper examining the advantages and disadvantages of auction-based, customer-based, and generator-based approaches to allocating carbon allowances. Developed recommendations for avoiding the introduction of inefficient investment, retirement, and operational incentives under each type of design, and for mitigating customer cost impacts.
- **Power Market Impacts of Clean Power Plan Alternatives.** Conducted a modeling assessment of price, cost, and emissions implications of different rate-based, subcategory rate-based, and mass-

based implementation of the Clean Power Plan in Texas. Estimated energy, emission reduction credit, and carbon prices under each scenario, and net revenue and operating implications for several types of generating plants.

- **Review of Hydropower Industry Implications under Clean Air Act 111(d).** For the National Hydropower Association, provided members review of the implications for new and existing hydropower resources of proposed EPA Clean Power Plan under Clean Air Act Section 111(d). Analyzed impacts under a variety of potential revisions to the proposed rule, different potential state compliance options, differing plan regulatory statuses, mass-based vs. rate-based compliance, regulated planning vs. market-based compliance, and cooperative vs. stand-alone compliance.
- **Enabling Canadian Imports for U.S. Clean Energy Policies.** For a coalition of Canadian electricity producers and policymakers, reviewed a range of options for U.S. states to pursue clean energy policies and the Clean Power Plan while enabling contributions from clean energy imports.
- **Clean Power Plan Regulatory and Stakeholder Support.** For a cooperative entity, provided support in developing internal and external positioning associated with the Clean Power Plan. Analyzed state-wide emissions targets and compliance alternatives. Supported messaging and stakeholder engagement at the state and federal levels. Submitted testimony before the Environmental Protection Agency.
- **State Compliance Strategy under the Clean Power Plan.** For a regulated utility, evaluated options and feasibility of meeting state standards under 111(d) rate standards under a number of compliance scenarios. Developed an hourly dispatch model covering backcast and forecast years through the interim and final compliance timelines, accounting for impacts of load growth, renewables growth, coal-to-gas redispatch, coal minimum dispatch constraints, planned retirements, new generation development, and export commitments. Estimated the ability to meet the standard under various compliance strategies.
- **New Gas Combined Cycle Plants Under the Clean Power Plan.** For the National Resources Defense Council, developed a whitepaper evaluating the economic implications of Clean Power Plan implementation plans that do or do not cover gas combined cycle plants on a level basis with other fossil-emitting plants. Conducted simulation analyses comparing the economic and emissions implications of alternative approaches.
- **MISO Coal Retrofit Supply Chain Analysis.** For the MISO, analyzed the fleet-wide requirements for retrofitting plants to upgrade for the Mercury and Air Toxics Standard. Reviewed the upstream engineering services, procurement, and construction supply chain to evaluate the ability to upgrade the fleet within the available time window. Analyzed the potential for operational and reliability concerns from simultaneous planned outages needed to support fleet-wide retrofit requirements in the MISO footprint.
- **Impact of Environmental Policies on Coal Plant Retirement.** For a PJM market participant, conducted a zone-level analysis of PJM market prices and used unit-level data to conduct a virtual dispatch of coal units under a series of long-term capacity, fuel, and carbon price

scenarios. Modeled retirement decisions of plants by PJM zone and the effect of the carbon price on the location and aggregate size of these retirement decisions.

CAPACITY MARKET DESIGN

- **PJM Review of Capacity Market Design and Demand Curve Parameters: 2011, 2014, and 2018.** For PJM Interconnection, conducted independent periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, net cost of new entry parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Provided expert support to stakeholder proceedings, testimony submitted before the Federal Energy Regulatory Commission, and before the Maryland Public Service Commission.
- **Integrated Clean Capacity Market (ICCM).** For the New Jersey Board of Public Utilities, supported a Board investigation of alternative resource adequacy structures in alignment with the state's 100% by 2040 economy-wide clean energy mandates. Developed detailed design proposal for the ICCM and conducted economic modeling of clean energy achievement and customer costs across alternative design structures. Supported a series of stakeholder engagements to review alternative structures.
- **New York Capacity and Resource Adequacy Alternatives.** For the New York Department of Public Service and New York State Energy Research & Development Authority, conducted a study evaluating a range of capacity market and resource adequacy alternatives. Implemented modeling analysis of impacts across alternative capacity market designs, minimum offer price rule scenarios, and interactions with state clean energy mandates. Supported a technical workshop and authored reports filed within docket proceedings.
- **Maryland Resource Adequacy Alternatives.** For the Maryland Environmental Service and Maryland Energy Administration, conducted an analysis of resource adequacy and capacity market alternatives in alignment with state clean energy policy. Conducted modeling analysis, authored a public report, and presented results to state policymakers.
- **Alberta Energy-Only Market Review for Long-Term Sustainability: 2011 and 2013 Update.** For AESO, conducted a review of the ability of the energy-only market to attract and retain sufficient levels of capacity for long-term resource adequacy. Evaluation of the outlook for revenue sufficiency under forecasted carbon, gas, and electric prices, potential impact of environmentally-driven retirements, potential federal coal retirement mandate, and provincial energy policies.
- **Singapore Capacity Market Design.** For the Energy Market Authority, supported market design and market rules development for all aspects of the new capacity market design. Supported an iterative series of stakeholder engagements to iteratively refine market rules.

- **Economic Implications of Resource Adequacy Requirements.** For the U.S. Federal Energy Regulatory Commission, reviewed economic and reliability implications of resource adequacy requirements based on traditional reliability criteria as well as alternative standards based on economic criteria. Evaluated total system costs, customer costs, supplier net revenues, and demand response implications under a range of reserve margins as well as under different energy-only and capacity market designs.
- **Winter Resource Adequacy and Reliability.** For an RTO, analyzed the risk of winter reliability and resource adequacy shortages. Examined the drivers of winter reliability concerns including unavailability of specific resource types, winter fuel supply shortages, and weather-driven outages. Developed a range of potential reforms for addressing identified concerns.
- **Testimony on the Impacts of the Minimum Offer Price Rule.** For a coalition of environmental organizations, authored testimony on the economic impacts of the Minimum Offer Price Rule in the New York capacity market, filed before the Federal Energy Regulatory Commission.
- **Alberta Capacity Market Design.** Supported the development of a capacity market design in Alberta. Provided expert support to public working groups and AESO staff to review analytical questions, develop and evaluate design alternatives, and draft design documents. Supported on all aspects of market design including establishing reliability requirements, developing demand curve parameters, evaluating seasonal capacity resources, setting capacity ratings, product definition and obligations, and penalty mechanisms.
- **European Market Flexibility and Capacity Auction Design.** For European client, developed a market-based design for meeting flexible and traditional capacity needs in the context of high levels of intermittent resource penetration, degraded energy and ancillary pricing signals, and ongoing electricity market reforms. Engaged in meetings with industry and European Commission staff to develop and refine design options. Developed a model simulating market clearing results in a two-product auction and projecting prices over time.
- **Italian Capacity Market Design.** For Italy's transmission system operator Terna, supported development of a locational capacity market design and locational capacity demand curves based on simulation modeling on the value of capacity to customers.
- **Capacity Auction Design for Western Australia**. For Western Australia's Public Utility Office, drafted a whitepaper and advised on the design of its new capacity auction mechanism.
- **IESO Capacity Auction Design.** Provided expert support to IESO staff in support of a new capacity auction design. Provided detailed memos describing options, tradeoffs, and lessons learned on every aspect of capacity auction design. Supported stakeholder engagement, conducted analysis of design alternatives, and developed design proposals.
- **PJM Seasonal Capacity Market Design.** For the Natural Resources Defense Council, provided testimony and economic analysis in support of improving the capacity market design to better accommodate seasonal capacity resources.
- **ISO New England Capacity Demand Curve**. For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their

efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Submitted Testimony before the Federal Energy Regulatory Commission supporting a proposed system-wide demand curve, with ongoing support to develop locational demand curves for individual capacity zones.

- **MISO-PJM Capacity Market Seams Analysis.** For MISO, evaluated barriers to capacity trade with neighboring capacity markets, including mechanisms for assigning and transferring firm transmission rights and cross-border must-offer requirements. Evaluated economic impacts of addressing the barriers and identified design alternatives for enabling capacity trade.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the Federal Energy Regulatory Commission.
- **Capacity Market Manipulation.** For a market participant, supported economic and policy analysis of an alleged instance of capacity market withholding.
- **Demand Curve and Net Cost of New Entry Review.** For an RTO, provided a high-level conceptual review of its approach to establishing demand curve and net cost of new entry parameters. Identified potential reliability and economic efficiency concerns, and recommended enhancements.
- **Western Australia Reserve Capacity Mechanism and Transition Mechanism**. For EnerNOC, authored two public reports related to the energy market reforms in Western Australia. The first report evaluated the characteristics of the Western Australia Reserve Capacity Mechanism in comparison with international best practices and made recommendations for improvements, whether pursuing a capacity market or energy-only market design. The second report evaluated and recommended changes to the regulator's proposed mechanism for transitioning to its long-term capacity market design.
- **MISO Resource Adequacy Construct.** For MISO, conducted a review of MISO's resource adequacy construct. Subsequent assistance to MISO in enhancing the market design for resource adequacy related to market redesign, capacity market seams, and accommodation of both regulated and restructured states. Provided background presentations to stakeholders on the capacity market design provisions of NYISO, PJM, CAISO, and ISO-NE.
- **Cost of New Entry Study to Determine PJM Auction Parameters: 2011 and 2014.** For PJM Interconnection, partnered with engineering, procurement, and construction firm to develop bottom-up cost estimates for building new gas combined cycles and combustion turbines. Affidavit before the Federal Energy Regulatory Commission and participation in settlement discussions on the same.

Wholesale Energy, Ancillary, and Specialized Products Market Design

- **Greece Energy and Ancillary Service Market Reform.** For the Hellenic Association of Independent Power Producers, provided expert advice and a report on how to reform wholesale power markets to conform with policy mandates and meet system flexibility needs. Analyzed energy and ancillary market pricing and rules to identify opportunities to enhance efficiency, improve participation of emerging resources, achieve market coupling, and better integrate intermittent resources. Proposed high-level design recommendations for implementing forward, day-ahead, intraday, and balancing markets consistent with European Target Model requirements. Developed detailed design recommendations for near-term and long term enhancements to market operations, pricing, dispatch, and settlements. Provided expert support in meetings with European Commission staff.

- **Ramping Product Design.** For a market operator, developed a design proposal for a ramping product that would serve system ramping needs across multiple forward intervals and across locations. Developed rules that would enable distributed and demand response resources to participate in providing system ramping needs and incentives to become visible and controllable by the system operator.

- **Alberta Energy and Ancillary Service Market Enhancements.** Supported the development of market design enhancements to better support flexibility needs and align with capacity market implementation. Developed design proposals and evaluated alternatives for immediate and long-term reforms including monitoring and mitigation, enhanced administrative scarcity pricing, ancillary service co-optimization, day-ahead markets,

- **SPP Ramp Product Proposal.** For Golden Spread Electric Cooperative, developed recommendations for the design and implementation of a ramping product to most efficiently and cost-effectively manage intermittency needs. Reviewed opportunities to determine the most appropriate quantity of resources, forward product timeframe, price formation, and interactions with existing pricing and commitment procedures.

- **ERCOT Energy Market Design and Investment Incentives Review.** For the Electric Reliability Council of Texas (ERCOT), conducted a study to: (a) characterize the factors influencing generation investment decisions; (b) evaluate the energy market's ability to support investment and resource adequacy at the target level; (c) examine efficiency of pricing and incentives for energy and ancillary services, focusing on scarcity events; and (d) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Performed forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Supported ongoing proceedings with stakeholders and before the Public Utility Commission of Texas.

- **Scarcity and Surplus Event Pricing.** For an RTO, examined the efficiency and reliability implications of its pricing mechanisms during scarcity and surplus events, and evaluated potential market reforms. Options reviewed included adjusting the price cap consistent with the value of lost load, adjusting supplier offer caps, imposing administrative scarcity prices at varying levels of emergency events, ancillary service market pricing interactions, and reducing the price floor below zero.

- **MISO Wind Curtailment Interactions with Energy Market Pricing and Transmission Interconnection Processes.** For MISO, evaluated the efficiency and equity implications of wind curtailment prioritization mechanisms and options for addressing stakeholder concerns, including interconnection agreement types, energy and capacity injection rights, ARR/FTR allocation mechanisms, energy market offers, and market participant hedging needs.
- **Survey of Energy Market Seams.** For the Alberta Electric System Operator (AESO), assessed the implications of energy market seams inefficiencies between power markets in Canada, the U.S., and Europe for the Alberta Electric System Operator. Evaluation of options for improving seams based on other markets' experiences with inter-regional transmission upgrades, energy market scheduling and dispatch, transmission rights models, and resource adequacy.
- **New England Fuel Security Market Design.** For NextEra, developed design proposals for using market-based mechanisms to meet regional fuel security needs including through a fuel security reserve product that would enhance pricing and operations for fuel security in the energy and ancillary service markets, and options for a long-term solution through forward auctions for fuel security.
- **Reliability Auctions for the NEM.** For the Australian Electricity Market Operator conducted an international review of the range of approaches to supporting reliability and system security through competitive auctions. Focused on product definition including, various aspects of reliability and system security, auctions focused on enabling non-traditional resource types, options ranging from strategic reserve models to partial needs procurements to capacity markets, and potential for impacts on energy-only market pricing and performance.
- **ERCOT Operating Reserves Demand Curve and Economically Optimal Reserve Margin 2014 and 2018.** For the Public Utility Commission of Texas and ERCOT, co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.
- **Financial Transmission Right and Virtual Bidding Market Manipulation Litigation for PJM.** For PJM Interconnection, analyzed financial transmission rights, energy market, and virtual trading data for expert testimony regarding market manipulation behavior.
- **Southern Company Independent Auction Monitor.** For Southern Company, developed auction monitoring capability and protocol development for monitoring hourly and daily auctions. Supported functions included daily and annual audits of internal company processes and data

inputs related to load forecasting, purchases and sales, and outage declarations. Analyzed company data to develop monitoring protocols and automated tools. Coordinated implementation of data collection and aggregation system required for market oversight and for detailed internal company data audits.

GENERATION AND TRANSMISSION ASSET VALUATION

- **Revenue Projections for Generation and Transmission Assets (Multiple Clients).** For multiple clients, top-line operating cost and revenues estimation for generation and transmission assets in PJM, ISO-NE, MISO, SPP, and ERCOT; experience with a range of asset types including gas CCs, gas CTs, coal, renewables, waste-to-energy, cogeneration, and HVDC lines. Evaluation exercises include forecasting market prices and net revenues from energy, capacity, ancillary service, and (if applicable) renewable energy credit markets. Valuations account for the operational impacts and economic value of existing power purchase agreements and other hedges. Clients typically require qualitative and quantitative analysis of regulatory risks under a range of operational and market scenarios. Valuation efforts often conducted in the context of due diligence for transactions, business decisions, and contract negotiations.
- **Executive Education and Investment Opportunities Surveys (Multiple Clients).** For multiple clients, provided executive education and detailed survey material to support investments in new markets and strategic decision-making. Educational efforts provided over a range of levels including high-level executive sessions, all-day workshop sessions, and detailed support for analytical teams. Examples of subject matter include: (a) cross-market surveys comparing investment attractiveness in many dimensions based on market fundamentals, regulatory structure, and contracting opportunities; and (b) single-market deep-dive educational sessions on capacity, energy, ancillary service, and financial/hedging product functioning and market performance.
- **In-House Fundamentals Capability Development (Multiple Clients).** For multiple clients, supported the development of in-house capability for market fundamentals analysis. Typically needed in the context of new entrants to a market or system operators expanding the scope of their internal analytical capabilities. Scope of support has included: (a) initial education, backup support, and advisory support for fundamentals teams entering a new market; (b) development and transfer of new purpose-built modeling tools such as capacity market models; and (c) external peer review or independent assessment functions.
- **Asset or Fleet Valuation in Support of Litigation and Arbitration Proceedings (Multiple Clients).** In litigation and arbitration contexts, provided estimates of economic damages or asset/fleet value estimates that would have applied at the time of a particular business decision. Supported expert testimony, litigation workpapers, and assessment of opposing experts' analysis.
- **Economic Analysis of Plant Retrofit and Fuel Contracting Decisions (Multiple Clients).** Supported plant operational and investment decisions for enhancing the value of particular assets, including contexts such as: (a) retrofitting plants from oil to gas generation; (b) retrofitting single-cycle to combined cycle with different capacities for duct firing; (c)

enhancing ancillary service capability; and (d) and contracting for firm gas capability. Evaluated operational, cost, and revenue impacts of alternatives and compared to present investment costs.

- **Financial Implications of Regulatory, Policy, and Market Design Changes (Multiple Clients).** Conducted analyses of risks and opportunities associated with regulatory, policy, and market design changes. Examples include an analysis of potential Trump administration policies, implications of potential clean energy and carbon policies, and assessing private risks from changes to ancillary service market rules.

Integration of Emerging Technologies

- **Revenue Projections for Storage, Hybrid, Renewable, Demand Response, and Distributed Resource Technologies (Multiple Clients).** For multiple clients across many wholesale electricity markets, conducted projections of net revenues available to assets of many different technology types considering: access to participate in various wholesale electricity products, opportunities to sell environmental attributes or earn policy incentives, and contracted asset revenues. Provided revue projections across alternative market and policy scenarios and alternative asset configurations, in the context of informing investment strategy and investor due diligence. Review policy context and regulatory uncertainties that may enhance or erode market opportunities for particular assets or investment portfolios of emerging resources.
- **RTO Business Models Analysis for Enabling Customer-Side Disruption and the Clean Energy Future.** For a system operator, engaged in an executive strategy analysis to evaluate a range of electricity sector business models under a future with high penetrations of distributed resources and decarbonization. Developed detailed scenario descriptions of the business models envisioned considering different roles and scope of services provided by the RTO, distribution companies, load serving entities, and third-party aggregators. Created an interactive tool for mapping financial flows and energy flows at all points in the electricity value chain under each business model considered, and drew implications for value proposition of each segment of the market.
- **Enabling Market Participation from Non-Emitting and Emerging Technologies.** For an Ontario stakeholder group, provided expert support to identify market design enhancements to enable and integrate non-emitting and emerging technologies. Examined participation barriers and design enhancements to unlock full value of resources for supporting energy, flexibility, capacity, and other value streams to the province.
- **New Jersey Offshore Wind Transmission Solicitation.** For the New Jersey Board of Public Utilities, supporting the competitive solicitation of transmission investments to support the integration of up to 7,500 MW of offshore wind, including solutions for on-shore upgrades, offshore connections, and offshore network options. Economic, environmental, and legal analysis will support Board selection of winning projects under the first-ever PJM State Agreement Approach process for transmission development in support of state policies.
- **International Review of Demand Response Integration into Wholesale Electricity Markets.** For the Australian Energy Market Commission, authored a report describing the range of

approaches and market experience integrated demand response into wholesale energy, ancillary service, and capacity markets. Provided detailed discussion of approaches in Singapore, Alberta, ERCOT, PJM, ISO New England, and Ontario. Summarized lessons learned regarding demand response business models, efficient wholesale pricing signals, and interactions with retail markets.

- **Integration of Energy Efficiency in Capacity Markets.** For Advanced Energy Economy, developed a series of papers focused on best practices for integrating energy efficiency into wholesale capacity markets in a competitive, resource-neutral fashion that enables all business models.
- **Integration of Demand Response into Ontario Energy Markets.** For the Ontario market operator, conducted a review of opportunities to better integrate demand response into energy market dispatch, price formation, and settlements. Reviewed interactions amongst capacity, energy, and retail pricing incentives. Authored a recommendations report, evaluated the magnitude of potential consumer benefits, and supported stakeholder engagement.
- **Oncor Distributed Storage Business Models to Supply Customer, Distribution System, and Wholesale Value Streams**. For Oncor Electric Delivery Company, conducted a benefit-cost analysis of adding varying levels of distributed storage into the Texas market. Recommended policy changes to enable storage under a range of business models (merchant, utility-owned, customer-owned, and third-party owned), and to allow for the development of resources that could provide multiple value streams. Value streams considered including market values such as energy and ancillary services, distribution-system values including deferred transmission and distribution costs, and customer value streams including avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.
- **Risk and Financial Analysis of PJM Capacity Performance Product.** For a market participant, conducted a probabilistic assessment of the expected value, upside, and downside risks (both market-wide and private) associated with PJM's capacity performance product. Evaluated the likely frequency of scarcity events on average and as concentrated in particular years to estimate the expected value of bonus payments if operating as an energy-only asset, and the net potential bonus/penalty if operating as a capacity performance resource. Estimated risk-neutral and risk-averse capacity price offer levels; characterized the magnitude of risk exposure of poor asset performance coincided with system scarcity events.
- **Capacity Auction Design and Auction Clearing Software Testing**. For a system operator, assisted in the high-level and detailed designs of a capacity auction. Supported market rule development and auction clearing optimization specification. As part of software implementation testing, developed optimization engine in GAMS/CPLEX to replicate auction clearing results, conducted quality control testing of auction clearing engine across 100+ test cases to ensure fidelity and consistency with market rules; conducted software quality control testing across multiple design iterations across several years.
- **Hedging Products for Wind**. For a hedge fund, provided analytical support for the development of a hedging product for wind developers. Evaluated the risk exposure based on day-ahead and

real-time participation, locational price differentials, profile and curtailment risks, and discrepancies with exchange-traded hedging products.

- **Tariff Design for Merchant Transmission Upgrades.** For a transmission developer, evaluated tariff design options for capturing market value of wind and transmission for a market participant proposing a large HVDC upgrade to enable wind developments.
- **Magnitude and Potential Impact of "Missing Efficiency" in PJM.** For the Natural Resources Defense Council, analyzed the potential magnitude of energy efficiency programs in PJM that are not accounted for on either demand side (through load forecast adjustments) or on the supply side (in the capacity market). Estimated potential energy and capacity market customer cost impacts in both the short-run and long-run if adjusting the load forecast to account for the missing efficiency.
- **Market Reforms to Meet Emerging Flexibility Needs.** For the Natural Resources Defense Council, authored a report on the electricity market reforms needed in the context of declining needs for baseload resources, increasing levels of intermittent supply, and increasing needs for flexible resources.

REPRESENTATIVE PUBLICATIONS

Papers and Reports

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Chang, Judy, Mariko Geronimo Aydin, Johannes P. Pfeifenberger, Kathleen Spees, and John Imon Pedtke. *Advancing Past "Baseload" to a Flexible Grid: How Grid Planners and Power Markets are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix.* Prepared for the Natural Resources Defense Council. June 26, 2017.

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Spees, Kathleen, Yingxia Yang, and Yeray Perez. *Energy and Ancillary Services Market Reforms in Greece: A Path to Enhancing Flexibility and Adopting the European Target Model.* Prepared for the Hellenic Association of Independent Power Producers (HAIPP). May 2017.

Pfeifenberger, Johannes, Kathleen Spees, Judy Chang, Mariko Geronimo Aydin, Walter Graf Peter Cahill, James Mashal, John Imon Pedtke. *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project.* Prepared on behalf of the Independent Electricity System Operator. Draft Report March 3, 2017.

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Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, and Roger Lueken. "Open Letter to GAO: Response to U.S. Senators' Capacity Market Questions." Submitted to the U.S. Government Accountability Office. May 5, 2016.

Spees, Kathleen, Samuel A. Newell, and Colin A. McIntyre. *Western Australia's Transition to Competitive Capacity Auction*. Prepared on behalf of EnerNOC. January 29, 2016.

Chupka, Metin Celebi, Judy Chang, Ira H. Shavel, Kathleen Spees, Jürgen Weiss, Pearl Donohoo-Vallett, Michael Hagerty, and Michael A. Kline. *The Clean Power Plan: Focus on Implementation and Compliance.* Published by The Brattle Group, Inc. January 2016.

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Spees, Kathleen, Samuel A. Newell, David Luke Oates and James Mashal. "Clean Power Plan in Texas: Implications for Renewables and the Electricity Market," Presented at the 2016 Renewable Energy Law Conference. February 9, 2016.

Pfeifenberger, Johannes P., Judy Chang, Kathleen Spees, and Matthew K. Davis. "Impacts of Distributed Storage on Electricity Markets, Utility Operations, and Customers," 2015 MIT Energy Initiative Associate Member Symposium. May 1, 2015.

Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," Energy Storage Policy Forum 2015, Washington, D.C. January 29, 2015.

Spees, Kathleen. "EPA's Clean Power Plan: Potential Impacts on Asset Values," Infocast 7th Annual Projects & Money Summit 2015. January 13, 2015.

Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," UBS Investment Research Webinar. December 5, 2014.

Spees, Kathleen and Judy Chang. "Evaluating Cooperation Opportunities under CAA 111(d)," Presented to the Eastern Interconnection States' Planning Council. October 2, 2015.

Spees, Kathleen. "Implications of EPA's Clean Power Plan under Clean Air Act Section 111(d)," Presented to the Department of Engineering and Public Policy at Carnegie Mellon University. September 18, 2015.

Spees, Kathleen, Samuel A. Newell, and Johannes P. Pfeifenberger. "ERCOT's Optimal Reserve Margin: As Estimated for the Public Utility Commission of Texas and the Electric Reliability Council of Texas," presented to the 2014 Texas Industrial Energy Consumers Annual Meeting. July 15, 2014.

Pfeifenberger, Johannes P., Samuel A. Newell, and Kathleen Spees. "Energy and Capacity Markets:

Tradeoffs in Reliability, Costs, and Risks," presented at the Harvard Electricity Policy Group Seventy-Fourth Plenary Session. February 27, 2014.

Spees, Kathleen, Johannes P. Pfeifenberger, and Samuel A. Newell. "ERCOT's Optimal Reserve Margin," presented to UBS Investment Research investor conference call. February 19, 2014.

Spees, Kathleen. "Capacity Markets: Lessons Learned from the First Decade," presented to EUCI 10th Annual Capacity Markets Conference. November 7, 2013.

Pfeifenberger, Johannes P, and Kathleen Spees. "Characteristics of Successful Capacity Markets," presented at the APEx Conference 2013, New York. NY. October 31, 2013.

Spees, Kathleen and Johannes Pfeifenberger. "Outlook on Fundamentals in PJM's Energy and Capacity Markets," presented at the 12th Annual Power and Utility Conference, Hosted by Goldman Sachs. August 8, 2013.

Newell, Samuel A., and Kathleen Spees. "Get Ready for Much Spikier Energy Prices: The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented at the Cadwalader Energy Investor Conference. February 7, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. "PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update," presented to Barclays North American Utilities Investor Call. February 4, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. "Seams Inefficiencies: Problems and Solutions at Energy Market Borders," presented at the EUCI Canadian Transmission Summit. July 17, 2012.

Spees, Kathleen. "New U.S. Emission Regulations: Electric Industry Impacts," presented at the U.S. Energy 24th Annual Energy Conference. May 11, 2012.

Spees, Kathleen. "Market Design from a Practitioner's Viewpoint: Wholesale Electric Market Design for Resource Adequacy," presented at Lawrence University Economics Colloquium. April 23, 2012.

Spees, Kathleen. "Options for Extending Forward certainty in Capacity Markets." Presented at the EUCI Conference on Capacity Markets: Achieving Market Price Equilibrium. November 9, 2011.

Spees, Kathleen, and Pfeifenberger, Johannes P. "Resource Adequacy: Current Issues in North American Power Markets." Presented at the Alberta Power Summit. November 19, 2011.

Spees, Kathleen and Samuel Newell. "Capacity Market Designs: Focus on CAISO, NYISO, PJM, and ISO-NE," Presented to the Midwest ISO Supply Adequacy Working Group. July 19, 2010.

Pfeifenberger, Johannes P., and Kathleen Spees. "Best Practices in Resource Adequacy," presented at the PJM Long Term Capacity Issues Symposium. January 27, 2010.

Chang, Judy, Kathleen Spees, and Jurgen Weiss. "Using Storage to Capture Renewables: Does Size Matter?" working paper presented at the 15th Annual POWER Research Conference. University of California Energy Institute's Center for the Study of Energy Markets. March 18, 2010.

Samuel Newell

PRINCIPAL

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Dr. Newell leads Brattle's Electricity Group of over 50 consultants addressing the most challenging economic questions facing an industry transforming to clean energy.

His expertise centers on electricity wholesale markets, market design, generation asset valuation, integrated resource planning, and transmission planning. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Electricity Litigation & Regulatory Disputes

EDUCATION

- **Massachusetts Institute of Technology**
  PhD in Technology Management and Policy
- **Stanford University**
  MS in Materials Science and Engineering
- **Harvard University**
  AB in Chemistry and Physics

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2004–Present)**
  Principal
- **Cambridge Energy Research Associates (2003–2004)**
  Director
- **Kearney (1998–2002)**
  Manager

CAPACITY MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **PJM's Capacity Market Reviews and Parameters**. For PJM, conducted all five official reviews of its Reliability Pricing Model (2008, 2011, 2014, 2018, and 2022). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE) parameter, and the methodology for estimating net energy and ancillary services revenues. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. Relatedly, have also provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources, for use in the Minimum Offer Price Rule. Submitted testimonies before FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at FERC.
- **Buyer Market Power Mitigation in PJM**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Resource Accreditation**. Co-authored two whitepapers in 2022 for the Massachusetts Attorney General's Office on resource accreditation methodologies, including "ELCC" and empirical methods; evaluated reform options for New England.
- **ISO-NE Capacity Demand Curve Design.** For ISO New England (ISO-NE), developed a demand curve for its Forward Capacity Market. Solicited staff and stakeholder input, then established market design objectives. Provided a range of candidate curves and evaluated them against objectives, showing tradeoffs between reliability uncertainty and price volatility (using a probabilistic locational capacity market simulation model we developed). Worked with Sargent & Lundy to estimate the Net Cost of New Entry to which the demand curve prices are indexed. Submitted testimonies before FERC, which accepted the proposed curve.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO-NE, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity Market. Worked with Sargent & Lundy to conduct bottom-up analyses of the costs of constructing and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable, given

their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, reducing installed capacity requirements) for capacity costs and prices, emergency procurement costs, and energy prices. Whitepaper submitted by ISO-NE to the FERC.
- **New York State Resource Adequacy Constructs**. For NYSERDA, evaluated the customer cost impacts of several alternative constructs that differ in whether FERC or the state sets the rules and how buyer-side mitigation is implemented.
- **Evaluation of Moving to a Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a 4-year forward capacity market. Evaluated options based on stakeholder interviews and the experience of PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs. Recommendations were used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- **MISO Resource Adequacy Framework for a Transforming Fleet**. Currently advising MISO in its Resource Availability and Need initiative (2020-present) to reform its resource adequacy framework to address year-round shortage risks as the fleet transforms. Presenting to stakeholders on resource accreditation, determination of LSE requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before FERC.
- **MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.

- **Singapore Capacity Market Development**. For the Energy Market Authority (EMA) in Singapore, developed a complete forward capacity market design in 2018-2021. Worked with EMA in collaboration with other government entities and stakeholders. Published high-level design documents and presented to stakeholders. Currently assisting with detailed design and implementation.
- **Western Australia Capacity Market Design**. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design and implementation of a new forward capacity market. Reviewed the high-level forward capacity market design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; helped define administrative processes needed to conduct the auction and the governance of such processes.
- **Western Australia Reserve Capacity Mechanism**. For EnerNOC, evaluated Western Australia's administrative Reserve Capacity Mechanism in comparison with international capacity markets, and made recommendations for improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other senior government officials.

ENERGY & ANCILLARY SERVICES (AND OTHER) MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **ERCOT Post-Uri Market Reform**. Advised ERCOT and the Public Utility Commission of Texas regarding market design for reliability. Interviewed Commissioners, ERCOT, and stakeholders. Helped frame the problem as primarily resource adequacy and secondarily as operational reliability; evaluated market design proposals to support resource adequacy; evaluated refinements to the Operating Reserve Demand Curve and to Ancillary Services markets; presented recommendations and commented on stakeholder proposals at numerous PUCT workshops. Later invited by the State Energy Plan Advisory Committee to testify.
- **ERCOT's Proposed Future Ancillary Services Design**. For the Electric Reliability Council of Texas (ERCOT), evaluated the benefits of its proposal to unbundle ancillary services, enable broader participation by load resources and new technologies, and tune its procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load resources, and new technologies could participate. Directed their simulation of the market using PLEXOS, and evaluated other benefits outside of the model.
- **Investment Incentives in ERCOT**. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy; and (3) evaluate options to enhance resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability.

Conclusions informed a PUCT proceeding in which I filed comments and presented at several workshops.

- **Operating Reserve Demand Curve (ORDC) in ERCOT**. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted backcast analyses using interval-level data provided by ERCOT and assuming generators rationally modify their commitment and dispatch in response to higher prices under the ORDC. Analysis was used by ERCOT and the PUCT to inform selection of final ORDC parameters.
- **Economically Optimal Reserve Margins in ERCOT**. For ERCOT, co-led studies (2014 and 2018) estimating the economically-optimal reserve margin, and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load-shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- **Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals.** Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **IESO's Market Renewal Program / Energy Market Settlements**. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for the new day-ahead and real-time nodal market, including make-whole payments for natural gas-fired combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- **Forward Energy and Ancillary Services (EA&S) Revenues in PJM**. For PJM, developed a method for using forward prices to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters. Collaborated with Sargent &

Lundy to establish resource characteristics, and with PJM staff to conduct hourly virtual dispatch. Filed successful testimony with FERC.

- **Energy Price Formation in PJM**. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with FERC, and which FERC largely accepted and cited in its April 2019 Order.
- **Energy Market Monitoring & Market Power Mitigation**. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- **Market Design for Energy Security in ISO-NE**. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to the NEPOOL Markets Committee.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **Market Development Vision for MISO**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2–5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **RTO Accommodation of Retail Access**. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.
- **LMP Impacts on Contracts**. For a California state agency, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Estimated congestion costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using a third party's GE-MAPS market simulations (and helped

to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- **Australian Electricity Market Operator (AEMO) Redesign**. Advised AEMO on market design reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives; interviewed stakeholders; assessed local market characteristics affecting the design; synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The Public Utilities Office posted our whitepaper in support of its conclusions.

TRANSMISSION PLANNING AND MODELING

- **Initial Report on the New York Power Grid Study**. With NYSERDA, NYDPS, and Pterra, submitted a report to the NYPSC projecting New York's transmission needs to support its long-term clean energy goals under the Climate Leadership and Community Protection Act. Our work synthesized findings from three sub-reports addressing local T&D needs, offshore wind, and overall bulk system needs.
- **Value of a NY Public Policy Transmission Project**. On behalf of NY Transco LLC, submitted testimony in 2020 regarding the economic benefits of Transco's proposed "Segment B" transmission project. Critiqued an opposing expert's production cost analysis and broader benefit-cost analysis.
- **Benefit-Cost Analysis of New York AC Transmission Upgrades**. For the New York Department of Public Service (DPS) and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability between Upstate and Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift the location of future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. DPS used our analysis to inform its recommendation to the NY Public Service Commission to declare a "Public Policy Need" to build a project such as the best ones identified.
- **Evaluation of New York Transmission Projects**. For the New York Department of Public Service (DPS), provided a cost-benefit analysis for the "TOTS" transmission projects.

Showed net production cost and capacity resource cost savings exceeding the project costs, and the lines were approved. The work involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.

- **Economic and Environmental Evaluation of New Transmission to Quebec**. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- **Benefit-Cost Analysis of a Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the energy market impacts using the PROMOD model.
- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.
- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.
- **Analysis of Transmission Constraints and Solutions**. Performed a multi-client study identifying major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions. Worked with transmission engineers from client organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several economic major transmission projects.
- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle evaluation of commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and other models. Intensively tested each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability to calibrate models with backcasts using actual RTO data.

ENERGY POLICY ANALYSIS

- **Life Extension for Diablo Canyon**. For an environmental organization in CA in 2022, evaluated the net benefits of extending the operating life of the Diablo Canyon Nuclear Power Plant. Calibrated the base case in Brattle's gridSIM capacity expansion model to existing studies sponsored by CA state agencies, and estimated the impacts of retaining Diablo Canyon in terms of emissions, fixed and variable costs, and ability to meet both reliability objectives and clean energy goals.
- **Tariffs on PVs**. For a renewable energy advocacy group in 2022, evaluated the impacts of potential anti-circumvention tariffs that the Department of Commerce was considering imposing on PVs from four countries. Our team developed a trade model to estimate the impact on market prices for panels in the US; then leveraged our gridSIM capacity expansion model to estimate the impact on utility-scale investments, emissions, and energy prices/costs; then incorporated into a macroeconomic model to estimate effects on jobs and GDP.

- **Renewable Energy Tax Policy Impacts**. For ACORE, a renewable energy advocacy group, evaluated alternative proposals to extend and expand tax credits in 2021. Simulated investment, costs, prices and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model. Informed client's policy position.
- **Clean Energy Transformation**. For NYISO, led a team to project how the fleet may evolve to meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used gridSIM to model investment and operations subject to constraints on reliability and clean energy. Evaluated technology needs for meeting load during extended periods of low wind/solar. Study results helped inform questions about future market design and reliability.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad group of stakeholders opposing the rule in a filing before FERC, evaluated DOE's proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply; the likely cost of the rule; and the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.

GENERATION AND STORAGE ASSET VALUATION, AND PROCUREMENTS

- **Value of Flexibility in ERCOT**. For a large company evaluating a range of investment strategies, assessed the value of flexibility in ERCOT today and in the future as wind and solar penetration increases. Used Brattle's GridSIM model to project investments and retirements over the next 10 years. Analyzed the likely increase in demand for ancillary services. Simulated system operations accounting for short-term uncertainty in net load forecasts, using ENELYTIX PSO to model day-ahead and real-time operations.
- **Storage Development Company Due Diligence**. For an international investor consider an equity investment in a storage development company in ERCOT, reviewed the developer's business model, interviewed the developer, and compared their revenue projections to our own.
- **Storage Asset Development in New York**. For a renewable generation company considering developing large new storage assets in New York City and Long Island, provided a market analysis, including a 20-year estimate of net revenues. Used Brattle's GridSIM model to simulate investment, operations, prices, and revenues over that timeframe, after calibrating the model to current actual prices.
- **Valuation of a Gas-Fired Combined-Cycle Plant in ERCOT**. For a generation company, estimated net revenues for an existing plant, using Brattle's GridSIM model to project investment/retirement, operations, prices, and revenues over that timeperiod, after calibrating the model to recent prices. Assessed market risks.
- **Evaluation of Hydropower Procurement Options**. For a potential buyer of new transmission and hydropower from Quebec, evaluated costs and emissions benefits

under a range of contracting approaches. Accounted for the possibility of resource shuffling and backfill of emissions. Considered the value of storage services.

- **Valuation of a Gas-Fired Combined-Cycle Plant in New England**. For a party to litigation, submitted testimony on the fair market value of the plant. Simulated energy and capacity markets to forecast net revenues, and estimated exposure to capacity performance penalties. Compared the valuation to the transaction prices of similar plants and analyzed the differences. Collaborated with a co-testifying export on project finance to assess whether the estimated value would suffice to cover the plant's debt and certain other obligations.
- **Valuation of a Portfolio of Combined-Cycle Plants across the U.S.** For a debt holder in a portfolio of plants, estimated the fair market value of each plant in 2018 and the plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our own models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuation analyses across a range of scenarios. Provided insights into market and regulatory drivers and how they may evolve.
- **Wholesale Market Value of Storage in PJM**. For a potential investor in battery storage, estimated the energy, ancillary services, and capacity market revenues their technology could earn in PJM. Reviewed PJM's market participation rules for storage. Forecast capacity market revenues and the risk of performance penalties. Developed a real-time energy and ancillary service bidding algorithm that the asset owner could employ to nearly optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- **Valuation of a Generation Portfolio in ERCOT**. For the owners of a portfolios of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over a range of plausible scenarios. Analyzed the effects load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how future changes in these drivers could cause the value to shift over time.
- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially

on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.

- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a revenue forecast for energy and capacity. Evaluated the implications of several scenarios around key uncertainties.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net

energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

INTEGRATED RESOURCE PLANNING (IRP)

- **Resource Planning in Hawaii**. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- **IRP in Connecticut (for 2008, 2009, 2010, 2012, and 2014 Plans)**. For two major utilities and the state Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive IRPs. Plans involved projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, REC markets, and suppliers' likely investment/retirement decisions. Addressed electricity supply risks, natural gas supply into New England, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.
- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and

facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

DEMAND RESPONSE (DR) MARKET PARTICIPATION, MARKET POTENTIAL, AND MARKET IMPACT

- **Demand Response (DR) Integration in MISO**. Through a series of assignments, helped MISO incorporate DR into its energy market and resource adequacy construct, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers; (2) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets. Identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; (3) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying the practices of other RTOs and by characterizing the DR resources within the MISO footprint.
- **Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity.** For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Compensation Options for DR in ISO-NE's Energy Market**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **ERCOT DR Potential Study**. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the potential for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- **Wholesale Market Impacts of Price-Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic

retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.

- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Value of DR Investments**. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

GAS-ELECTRIC COORDINATION

- **Gas Pipeline Investment for Electricity.** For the Maine Office of Public Advocate, co-sponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other experts' reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- **Gas Pipeline Investment for Electricity.** For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- **Fuel Adequacy and Other Winter Reliability Challenges**. For an ISO, co-authored a report assessing the risks of winter reliability events due to inadequate fuel, inadequate weatherization, and other factors affecting resource availability in the winter. Evaluated solutions being pursued by other ISOs. Proposed changes to resource adequacy requirements and energy market design to mitigate the risks.
- **Gas-Electric Reliability Challenges in the Midcontinent**. For MISO, provided a PowerPoint report assessing future gas-electric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.

RTO PARTICIPATION AND CONFIGURATION

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on (1) MISO and PJM's real-time inter-RTO coordination process, and (2) the economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO's and PJM's energy prices and shadow prices on reciprocal coordinated flow gates.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

ENERGY LITIGATION

- **Enforcement Matter in ISO-NE's Day-Ahead Load Response Program**. Provided expert testimony on behalf of the FERC Office of Enforcement in "Fed. Energy Regulatory Comm'n v. Silkman" in the U.S. District Court of Maine regarding allegations that defendant "engag[ed] in a fraudulent scheme to manipulate the ISO New England, Inc. (ISO-NE) Day-Ahead Load Response Program" by gaming the baseline and claiming false reductions in load. Submitted initial and rebuttal reports analyzing whether defendant's conduct was consistent with industry practice and the purpose of demand response. Matter settled.
- **Valuation of Alleged Misrepresentations of Demand Response Company.** Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony before the American Arbitration Association (non-public).
- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice

charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's costs and operating characteristics. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

TARIFF AND RATE DESIGN

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

BUSINESS STRATEGY

- **Preparing a Gentailer for a Transformed Wholesale Market Design.** Supported a gentailer in Alberta to prepare its generation and retail businesses for the implementation of a capacity market.
- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility, evaluated a venture to build and operate cogeneration facilities. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Helped draft RFPs and develop negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance its trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the value client could bring to each customer. Worked with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a utility, performed a market assessment for DG technologies by segment in the U.S.
- **Fuel Cells**. For a fuel cell manufacturer, provided electricity market analysis to inform a market entry strategy in the U.S.

ARTICLES & PUBLICATIONS

- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 1: Foundation of Resource Accreditation, report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).

- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 2: Options for New England report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).
- *Offshore Wind Transmission: An Analysis of Options for New York*, report prepared for Anbaric, August 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- *Singapore Forward Capacity Market—FCM Design Proposal (third Consultation Paper)*, prepared for the Singapore Energy Market Authority, May 2020 (with J. Chang and W. Graf). Followed draft proposals in first and second Consultation papers in May 2019 and Dec 2019.
- *Quantitative Analysis of Resource Adequacy Structures*, report prepared for NYSERDA and NYSDPS, July 1, 2020 (with K. Spees, J. Imon Pedtke, and M. Tracy). Update to version from May 29, 2020.
- New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040 Including Alternative Scenarios, report prepared for NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Crocker Ross, and J. Moraski). Update to version from May 18, 2020.
- *Qualitative Analysis of Resource Adequacy Structures for New York*, report prepared for NYSERDA and NYSDPS, May 19, 2020 (with K. Spees and J. Imon Pedtke).
- *Offshore Transmission in New England: The Benefits of a Better-Planned Grid*, report prepared for Anbaric, May 2020 (with J. Pfeifenberger and W. Graf).
- *Implementing Recommended Improvements to Market Power Mitigation in the WEM*, report prepared for Energy Policy WA in Western Australia, April 2020 (with T. Brown).
- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, report prepared for PJM, March 17, 2020 (with M. Hagerty, S. Sergici, E. Cohen, S. Gang, J. Wroble, and P. Daou).
- "Forward Clean Energy Markets: A New Solution to State-RTO Conflicts," *Utility Dive*, January 27, 2020 (with K. Spees and J. Pfeifenberger.)
- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes: Expanded Report Including a Detailed Market Design Proposal, report prepared for NRG, September 2019 (with K. Spees, W. Graf, and E. Shorin).
- *International Review of Demand Response Mechanisms in Wholesale Markets*, report for the Australian Energy Market Commission, June 2019 (with T. Brown, K. Spees, and C. Wang).

- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes, report prepared for NRG, April 2019 (with K. Spees, W. Graf, and E. Shorin).
- *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, Final Draft*, prepared for the Electric Reliability Council of Texas, December 20, 2018 (with R. Carroll, A. Kaluzhny, K. Spees, K. Carden, N. Wintermantel, and A. Krasny).
- Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively, discussion paper, July 2018 (with K. Spees, J. Pfeifenberger, and J. Chang).
- *Fourth Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 16, 2018 (with J. Pfeifenberger, K. Spees, and others).
- *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Michael Hagerty, J. Pfeifenberger, S. Gang of Sargent & Lundy, and others).
- *Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule*, whitepaper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel).
- *Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions*, report prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, D.L. Oates, T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke).
- *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals*, whitepaper prepared for the New York Independent System Operator, August 11, 2017 (with R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee).
- "How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees).
- *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, whitepaper prepared for the Public Utilities Office in the Government of W. Australia's Department of Finance, September 1, 2016 (with T. Brown, W. Graf, J. Reitzes, H. Trewn, and K. Van Horn).
- *Western Australia's Transition to a Competitive Capacity Auction*, report prepared for Enernoc, January 29, 2016 (with K. Spees and C. McIntyre).

- *Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal*," report prepared for ERCOT, December 2015 (with R. Carroll, P. Ruiz, and W. Gorman).
- Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint—Options for MISO, Utilities, and States, report prepared for NRG, November 9, 2015 (with K. Spees and R. Lueken).
- *International Review of Demand Response Mechanisms*, report prepared for Australian Energy Market Commission, October 2015 (with T. Brown, K. Spees, and D.L. Oates).
- Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism, report prepared for EnerNOC, Inc., August 2014 (with K. Spees).
- *Third Triennial Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).
- *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pfeifenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).
- *Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).
- *Estimating the Economically Optimal Reserve Margin in ERCOT*, report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees, and I. Karkatsouli).
- "Capacity Markets: Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy*. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger and K. Spees).
- *ERCOT Investment Incentives and Resource Adequacy*, report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).
- "Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" *Public Utilities Fortnightly*, December 2011 (with J. Pfeifenberger).
- Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15, prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees).

- *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).
- "Fostering economic demand response in the Midwest ISO," *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).
- "DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.
- Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements, report prepared for MISO, January 2010 (with K. Spees and A. Hajos).
- Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design, report prepared for MISO, January 2010 (with A. Hajos).
- *Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market*, whitepaper for the NYISO and stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).
- *Fostering Economic Demand Response in the Midwest ISO*, whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).
- *Review of PJM's Reliability Pricing Model (RPM)*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).
- "Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).
- Enhancing Midwest ISO's Market Rules to Advance Demand Response, report written for MISO, March 12, 2008 (with R. Earle).
- "The Power of Five Percent," *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).
- Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).
- *Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets*, Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).
- "Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).

- *Quantifying Demand Response Benefits in PJM*, study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).
- "Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).
- "Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Observations and Implications of the 2021 Texas Freeze," presented to Power Markets Today webinar on the February 2021 ERCOT electricity failure, April 14, 2021.
- "Offshore Wind Transmission: An Analysis of Options for New York," presented at LCV Virtual Policy Forum, August 6, 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- "Possible Paths Forward from MOPR," presented to Power Markets Today webinar on "Capacity Market Alternatives for States," July 15, 2020.
- "Considerations for Meeting Sub-Annual Needs, and Resource Accreditation across RTOs," presented to MISO Resource Adequacy Subcommittee, July 8, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "New York's Evolution to a Zero Emission Power System—Modeling Operations and Investment through 2040 Including Alternative Scenarios," presented to NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Ross, and J. Moraski).
- "Singapore Foreward Capacity Market Design—Industry Briefing Sessions," presented via video to Singapore electricity market stakeholders, June 5&9, 2020 (with W. Graf).
- "Industry Changes in Resource Adequacy Requirements," presented to MISO Resource Adequacy Subcommittee, May 6, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," presented to NYISO Stakeholders, March 30, 2020 (with R. Lueken, J. Weiss, J. Moraski, and S. Ross).
- "Electricity Market Designs to Achieve and Accommodate Deep Decarbonization," presented to Advanced Energy Economy (AEE) video conference, "ISO-NE in 2050: Getting To An Advanced Energy Future In New England," March 18, 2020.

- “U.S. Offshore Wind Generation, Grid Constraints, and Transmission Needs,” presented at Offshore Wind Transmission, USA Conference, September 18, 2019 (with J. Pfeifenberger and K. Spokas).
- “Pollution Pricing in the Power Sector: Market-Friendly Tools for Incorporating Public Policy,” presented to GCPA Spring Conference, Houston, TX, April 16, 2019.
- “The Transformation of the Power Sector to Clean Energy: Economic and Reliability Challenges,” keynote address to the Power Engineers 4th Annual Power Symposium, Weehawken, NJ, April 4, 2019.
- “Market Design for Winter Energy Security in New England: Further Discussion of Options,” presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).
- “Market Design for Winter Energy Security in New England: Discussion of Options,” presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, January 9, 2019 (with D.L. Oates).
- “Market Equilibrium Reserve Margin in ERCOT,” presented to Power Markets Today webinar, “A Post Summer Check-in of ERCOT’s Market,” October 31, 2018.
- “Carbon Pricing in NYISO’s Wholesale Energy Market, and Applicability to Multi-State RTO markets,” presented to Raab Policy Roundtable, May 23, 2018; presented to the Energy Bar Association, 2018 EBA Energizer: Pricing Carbon in Energy Markets, June 5, 2018; presented to Bank of America Merrill Lynch, June 25, 2018.
- “Reconciling Resilience Services with Current Market Design,” presented to RFF/R-Street Conference on “Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System,” Washington, D.C., May 30, 2018.
- “System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches,” presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.
- “Natural Gas Reliability: Understanding Fact from Fiction,” panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).
- “Carbon Pricing in Wholesale Markets: Takeaways from NYISO Carbon Charge Study,” presented to Harvard Electric Policy Group, October 12, 2017.

- "Pricing Carbon into NYISO's Wholesale Energy Market: Study Overview and Summary of Findings," presented to NYISO Business Issues Committee, September 12, 2017.
- "Carbon Adders in Wholesale Power Markets—Preventing Leakage," panelist at Resources for the Future's workshop on carbon pricing in wholesale markets, Washington, D.C., August 2, 2017.
- "Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.
- "ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.
- "The Future of Wholesale Electricity Market Design," presented to Energy Bar Association 2016 Annual Meeting & Conference, Washington, DC, June 8, 2016.
- "Performance Initiatives and Fuel Assurance—What Price Mitigation?" presented to Northeast Energy Summit 2015 Panel Discussion, Boston, MA, October 27, 2015.
- "PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).
- "Energy and Capacity Market Designs: Incentives to Invest and Perform," presented to EUCI Conference, Cambridge, MA, September 1, 2015.
- "Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.
- Before the Arizona Corporation Commission, Commission Workshop on Integrated Resource Planning, Docket No. E-00000V-13-0070, presented "Perspectives on the IRP Process: How to get the most out of IRP through a collaborative process, broad consideration of resource strategies and uncertainties, and validation or improvement through market solicitations," Phoenix, AZ, February 26, 2015.
- "Resource Adequacy in Western Australia—Alternatives to the Reserve Capacity Mechanism (RCM)," presented to The Australian Institute of Energy, Perth, WA, October 9, 2014.
- "Customer Participation in the Market," panelist on demand response at Gulf Coast Power Association Fall Conference, Austin, TX, September 30, 2014.

- “Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy,” presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.
- “EPA’s Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d),” presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.
- “Capacity Markets: Lessons for New England from the First Decade,” presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.
- “The State of Things: Resource Adequacy in ERCOT,” presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.
- “Resource Adequacy in ERCOT,” presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.
- “Electricity Supply Risks and Opportunities by Region,” presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.
- “Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response,” presented to the Cadwalader Energy Investor Conference, New York, NY, February 7, 2013 (with K. Spees).
- “The Resource Adequacy Challenge in ERCOT,” presented to The Texas Public Policy Foundation’s 11th Annual Policy Orientation for legislators, Austin, TX, January 11, 2013.
- “Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives,” presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.
- “Resource Adequacy in ERCOT,” presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.
- “Texas Resource Adequacy,” presented to Power Across Texas, Austin, TX, September 21, 2012.
- “Resource Adequacy and Demand Response in ERCOT,” presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.
- “Summary of Brattle’s Study on ‘ERCOT Investment Incentives and Resource Adequacy’,” presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

- “Market-Based Approaches to Achieving Resource Adequacy,” presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.
- “Fundamentals of Western Markets: Panel Discussion,” WSPP’s Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with J. Weiss).
- “Integrated Resource Planning in Restructured States,” presentation at EUCI conference on “Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes,” White Plains, NY, October 17, 2011.
- “Demand Response Gets Market Prices: Now What?” NRRI teleseminar panelist, June 9, 2011.
- Before the PJM Board of Directors and senior level representatives at PJM’s General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.
- “Resource Adequacy in New England: Interactions with RPS and RGGI,” Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.
- “Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns,” Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.
- “Evaluating the Economic Benefits of Transmission Investments,” EUCI’s Cost-Effective Transmission Technology Conference, Nashville, TN, May 3, 2007 (with J. Pfeifenberger, presenter).
- “Quantifying Demand Response Benefits in PJM,” PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.
- “Who Will Pay for Transmission,” CERA Expert Interview, Cambridge, MA, January 15, 2004.
- “Reliability Lessons from the Blackout; Transmission Needs in the Southwest,” presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.
- “Application of the ‘Beneficiary Pays’ Concept,” presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

Exhibit No. 2

2022 VRR Curve Report

Fifth Review of PJM's Variable Resource Requirement Curve

FOR PLANNING YEARS BEGINNING 2026/27

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APRIL 19, 2022

Brattle

pjm

NOTICE

This report was prepared for PJM Interconnection, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

TABLE OF CONTENTS

Executive Summary

We have been commissioned by PJM Interconnection (PJM) to evaluate the parameters and shape of the administrative Variable Resource Requirement (VRR) curve used to procure capacity under the Reliability Pricing Model (RPM), as required periodically under the PJM Tariff.[1] For this Fifth Quadrennial Review, we have had more substantial opportunities to gather stakeholder feedback than in past reviews, including several rounds of stakeholder presentations and feedback sessions on preliminary analysis, in addition to individual meetings with stakeholder groups and the Independent Market Monitor (IMM).

Additionally we conducted this Fifth Quadrennial Review with special attention to PJM's Board and stakeholder stated priorities, which have emphasized three specific focus areas:[2]

- **Appropriate levels of procurement** needed to support the PJM's one-event-in-ten-years ("1-in-10"), or 0.1 loss of load events (LOLE) per year reliability standard;
- **Uncertainty in Net CONE** and the reference technology used for anchoring the VRR Curve; and
- **Changing resource mix in PJM and impact of potential reforms** that may materialize from the Resource Adequacy Senior Taskforce (RASTF).

We have conducted the entirety of this Quadrennial Review in light of the overarching design objectives of the RPM, with a particular emphasis on these focus areas.

RECOMMENDED CANDIDATE VRR CURVE AND WORKABLE RANGE

To assess the performance of the current VRR Curve and alternative curves, we have conducted both qualitative analyses and probabilistic simulation analyses, as required in the Tariff. In Figure 1 we summarize our recommended "Candidate Curve" (orange) to replace the current VRR Curve. The recommended Candidate Curve has a similar conceptual basis and similar simulated performance as compared to the current curve, but we recommend several adjustments as

1 PJM Interconnection, L.L.C. (2022). PJM Open Access Transmission Tariff. Effective January 1, 2022, ("PJM 2022 OATT"), Section 5.10 a.iii.

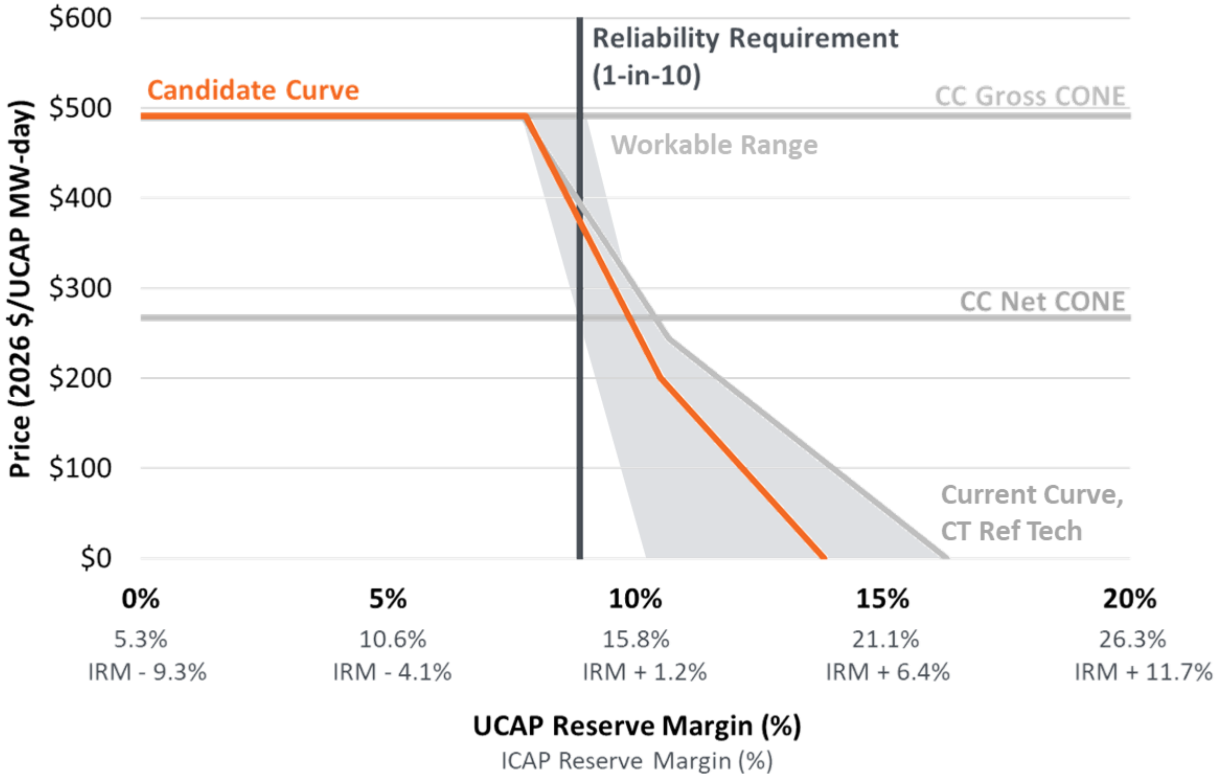
2 PJM, Board Letter Regarding Capacity Market Minimum Offer Price Rule and Initiation of the Critical Issue Fast Path Process, April 6, 2021; PJM, Resource Adequacy Senior Task Force, 2022.

compared to the current VRR Curve (grey) to balance among competing objectives in the RPM. Relative to the current VRR Curve, we recommend that the updated curve should:

- Adopt a combined cycle gas turbine (CC) as the reference technology, as documented in our separate study PJM CONE 2026/2027 Report, "2022 Net CONE Study."
- Maintain a medium-to-high price cap in the system-wide demand curve. We suggest raising the price cap formula to be the maximum of either 1.75 × Net CONE or Gross CONE. This would change the current Net CONE multiple from 1.5 to 1.75 and would ensure that the VRR price cap remains sufficiently high in the face of Net CONE uncertainty, even if future conditions differ from current Energy and Ancillary Service (E&AS) revenue offsets.
- Update the formula for the quantity points of the VRR Curve in unforced capacity (UCAP) MW terms, without reference to the Installed Reserve Margin (IRM), which is an ICAP metric.
- Maintain a quantity at the price cap equal or greater than 99% of the Reliability Requirement.
- Adjust the current curve shape to be slightly steeper to mitigate Net CONE uncertainty and reduce the curve foot to mitigate the potential for over-procurement. The specific quantity parameters in our Candidate Curve are 99%, 101.5%, and 104.5% of the Reliability Requirement for points A, B, and C respectively).

While we suggest one Candidate Curve as illustrated in the following figure, we acknowledge that there is a "workable range" of curves (shown approximately as the grey shaded area) which all would offer sufficient system reliability but with a differing balance of performance trade-offs.

FIGURE 1: RECOMMENDED "CANDIDATE" VRR CURVE
AND WORKABLE RANGE OF POTENTIAL VRR CURVE PARAMETERS



Sources/Notes: Candidate Curve price cap at Max(1.75 × CC Net CONE, **CC CONE**); Current Curve, CT Ref Tech price cap at Max(**1.5 × CT Net CONE**, CT CONE), bolded text indicates which parameter sets the price cap for each curve.

RECOMMENDATIONS RELATED TO VRR CURVE IMPLEMENTATION

Throughout this Quadrennial Review, we have identified a number of opportunities to improve the performance of the VRR Curve. These recommendations are driven by the overarching design objectives of the RPM and VRR Curve, which are to procure the volume of capacity needed to meet the 1-in-10 reliability standard in expectation while managing variability and uncertainty around that expectation, in addition to ensuring acceptable performance with respect to reliability outcomes, clearing price volatility, and mitigating the impacts from Net CONE uncertainty. Several of our recommendations related to our assessment of VRR Curve performance in light of the PJM Board and stakeholders' identified focus areas of achieving appropriate levels of procurement, managing uncertainties in Net CONE, and aligning with the changing resource mix and parallel market reforms.

Our recommendations are as follows:

1. **Eliminate over-forecast bias in the load forecast.** While acknowledging that the RPM must be robust to managing some unavoidable (but unbiased) load forecast error, we recommend

that PJM should eliminate the over-forecast bias historically seen in the load forecast. We understand that PJM has committed to and is in progress of addressing this issue. Changes adopted since approximately 2016 have indeed reduced the level of over-forecasting; however, we cannot conclude that PJM has fully eliminated the over-forecast bias based on evidence available to date. Though it is out of our scope to conduct a complete assessment of the load forecast methodology, we suggest the following adjustments to enhance the accuracy of the PJM load forecast and the ability of the RPM to manage the remaining unavoidable forecast error:

- In each load forecast report, explicitly estimate and report the uncertainty bands around the weather-normal peak load forecast by forward year (total error including model error and error in the independent variables), so as to better inform investment decisions, stakeholders, and future Quadrennial Reviews.

- Adopt a continuous improvement process for enhancing the load forecast over time, including: (1) retrospective annual reviews by PJM staff to diagnose the causes of realized forecast error (both weather-normalized and actual); and (2) periodic independent reviews of load forecast accuracy to identify opportunities for improvement. With continued changes to how electricity will be used by consumers, we anticipate that regular updates to the load forecast may be necessary to achieve the greatest possible load forecast accuracy.

- Align the Energy Efficiency (EE) resource participation model with the load forecast. Acknowledge that a centralized load forecast cannot realistically predict all EE activity across the PJM footprint. Therefore, we suggest that PJM reverts to the original concept for EE, namely, that supply-side EE can participate in the RPM if it demonstratively displaces the need for capacity that would otherwise be procured. Under this approach, PJM could develop the most accurate possible load forecast based on historical data, projected technology penetration rates, laws/regulations, and other predictors. This forecast would determine baseline assumptions with respect to the anticipated level of EE. At the same time, market participants could qualify energy efficiency as supply-side resources in the capacity market if they demonstrate that the EE measures are not already accounted for in the load forecast. EE resource UCAP ratings would decline over time as the baseline level of EE incorporated into the load forecast increases (declining to zero at the earlier of the EE measure life or when the load forecast is able to fully incorporate the measure). The EE add-back would then be eliminated from explicit consideration the VRR Curve, thus simplifying the VRR Curve and eliminating the need for iterative auction clearing associated with the EE add-back.

2. **Improve accuracy, transparency and consistency in capacity supply and demand accounting.** The need for enhanced accuracy in resource accounting has already been acknowledged by PJM and stakeholders as a priority to address in ongoing RASTF efforts. Through our assessment of historical levels of procurement, we have identified several opportunities to enhance resource accounting and reporting:

   - Transition to exclusive use of unforced capacity (UCAP) and forecast pool requirement (FPR) for all reliability and resource adequacy purposes. UCAP/FPR are a more accurate measure of capacity needs and commitments and are therefore already used for many purposes in the RPM including resource accounting and settlements. However, the less precise installed capacity (ICAP) and the Installed Reliability Margin (IRM) are still the primary (or intermediary) metrics presented for the purposes of: (a) setting the reliability standard (before converting to UCAP); (b) defining the quantity points on the VRR Curve (before converting to UCAP); and (c) issuing seasonal reliability assessments. We recommend PJM to utilize UCAP/FPR as the primary basis of measurement for all of these purposes.

   - Consider explicitly tracking reliability needs and supply commitments in the winter season. Our assessment of procurement levels has been inconclusive with respect to the winter season, given that supply and demand accounting within RPM is primarily associated with the summer season.

   - Consider updating other reliability and resource adequacy accounting reports (such as in seasonal reliability assessments) with the more accurate UCAP-based accounting approach utilized within the RPM. A portion of the stakeholder concerns about over-procurement may stem from a lack of consistency between RPM-based resource commitments and how seasonal reliability assessments are reported. Clarified reliability assessment reports can also clarify the distinction between resources that have RPM capacity commitments versus those that do not, given that non-committed resources may not be available to contribute to system reliability needs (e.g. due to export commitments or retirement).

3. **Adopt a gas-fired CC plant as the reference technology, while maintaining readiness to adopt a "clean" reference technology when needed.** The details of our recommendations related to the reference technology and Net CONE estimation are provided in our separate

2022 Net CONE Study. The pertinent subset of these recommendations relevant to this VRR Curve Study report are to:

- Adopt a gas CC as the reference technology to utilize in the system VRR Curve, as discussed in our 2022 Net CONE Study.
- Monitor States' environmental and clean energy policies across the PJM footprint to determine whether at any point it becomes clear that new fossil resources may not be feasible to develop in certain Locational Deliverability Areas (LDAs), particularly in the Commonwealth Edison (ComEd) and Public Service Electric & Gas (PSEG) regions of Illinois and New Jersey, respectively. If it becomes infeasible to develop fossil resources in these locations, adopt a clean reference technology in the affected LDAs.
- Continue to improve the ability to accurately estimate the Net CONE of one or more clean energy technologies such as batteries, solar, wind, and hybrid resources to enable the adoption of a clean reference technology if needed.

4. **Defer consideration of any additional left-shifting in the Base Residual Auction (BRA) VRR Curve.** Some stakeholders have suggested that the three-year forward BRA VRR Curve should be left-shifted to address over-procurement, with any remaining needs procured in the shorter-term Incremental Auctions (IAs). We agree that the best measurement of procurement relative to the reliability standard is the measurement immediately prior to the Planning Year. However, we do not recommend reducing procurement in the BRA below what is expected to achieve the 1-in-10 standard as of the time of the BRA because: (a) the above-recommended reforms will largely address the potential for over-procurement; and (b) there is little evidence that sufficient supply would be consistently offered in the short-term IAs to meet reliability needs in the case of a shortfall in the BRA. If the above-recommended reforms do not sufficiently achieve appropriate levels of procurement, we recommend that shifting some procurement into the shorter-term IAs should be studied and considered again in the next Quadrennial Review.

5. **Consider further adjustments to locational demand curves and associated auction clearing to moderate price volatility and manage reliability needs.** Consistent with our findings in prior Quadrennial Review, we anticipate that using one formula for VRR Curves across all sizes of LDAs will not provide a uniformly strong balance of RPM objectives. Particularly in small LDAs that are more susceptible to disproportionately large swings in supply, demand, and transmission constraints, prices can be more volatile, and reliability may be more severely affected by a shortfall. To address this concern, consider a transition to a Marginal Reliability

Impact (MRI)-based approach to setting locational VRR Curve and locational market clearing, similar to what is used in New England (or to what we have recommended in prior Quadrennial Reviews). Under the New England MRI-based curve approach, the locational VRR Curve would represent not the absolute price but the price premium (above parent LDA or system price) that would be paid to resources located in an import-constrained LDA. This demand curve approach has the potential to moderate price spikes in smaller LDAs, offer a more stable and moderated local price premium, and one that is more aligned with reliability value.

6. **As part of the ongoing RASTF, adopt conforming changes to improve performance of the VRR Curve.** Though the outcomes of the ongoing RASTF are not determined, we note several interactions among the VRR Curve and other design elements that should be updated on a joint basis to ensure consistency. Specifically:

   - Update the administrative Net CONE estimate to align with any changes to resource UCAP accounting, performance obligations, penalties, carbon pricing, or other factors that could materially affect the cost of developing new supply.

   - If PJM and stakeholders pursue a seasonal capacity market, take a fresh look at the VRR Curve shape and parameters. A seasonal capacity market may require different quantity points, reference technology, pricing parameters, and shape.

   - Simplify auction clearing by: (a) eliminating the iterative and heuristic steps associated with seasonal matching, locational clearing, and EE add-back, replacing these steps with a one-step optimized clearing; and (b) simplifying IA clearing based on a gross (rather than net) clearing optimization approach. These simplifications will improve market transparency, price formation, efficiency, and allow for other complexities that may be considered.

7. **Consider broadening the scope of future Quadrennial Reviews to the original, more comprehensive scope, as a full review of the RPM.** If there is a prospect that substantial ongoing refinements will be needed to RPM to continue supporting reliability throughout ongoing fleet transition, consider utilizing future Quadrennial Reviews as an opportunity for a regularized review and refinements.

I. Demand Curve Design Objectives

PJM's capacity market, called the Reliability Pricing Model (RPM), ensures long-term grid reliability by securing the required volume of capacity resources needed to meet predicted electricity demand in the future.[3] The RPM functions through an auction mechanism and consists of the Base Residual Auction (BRA), which procures capacity on a three-year forward basis, and three Incremental Auctions (IA), which serve to procure or release capacity closer to the Planning Year to right-size supply relative to reliability needs.[4]

The RPM employs a downward sloping demand curve, the Variable Resource Requirement (VRR) Curve, which is designed to fulfill the objectives summarized in Table 1. Some objectives such as meeting the 1-in-10 LOLE system-wide reliability standard and the 1-in to 25 conditional LOLE standard for the Locational Deliverability Areas (LDA) are codified in the PJM Tariff and PJM Manual, while others are our own interpretation of RPM's overarching role to support reliability and economic efficiency in a financially sustainable merchant investment context. These design objectives drive our assessment of VRR Curve performance, consistent with our approach in past Quadrennial Reviews.[5] We emphasize that there are inherent performance trade-offs between reliability outcomes, price volatility, procurement cost, and potential for over-procurement with a given VRR Curve shape and that any workable VRR Curve must ensure adequate performance while reasonably balancing these competing objectives.

We note that in addition to these design objectives, we conduct this Quadrennial Review while taking account of the three focus areas identified by PJM's Board and stakeholders, namely: appropriate levels of procurement, Net CONE and reference technology uncertainty, and interactions with ongoing reform efforts in the RASTF.

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3 PJM, Capacity Market (RPM), 2022.

4 The forward period for the first IA is 20 months, the second IA 10 months, and the third and final IA is 3 months prior to the Planning Year.

5 See PJM 2022 OATT, Section VI, Attachment C, Section 16; PJM, Manual 18, Section 2.2; Newell, *et. al.*, Fourth Review of PJM's Variable Resource Requirement Curve, Section IV.A, April 19, 2018; and Pfeifenberger, *et. al.*, Third Triennial Review of PJM's Variable Resource Requirement Curve, Section V.A.1, May 15, 2014.

TABLE 1: SUMMARY OF DESIGN OBJECTIVES OF VRR CURVE

Demand Curve Design Objectives	
Reliability	• Maintain 1-in-10 LOLE system-wide target on a long-term average basis; maintain 1-in to 25 conditional LOLE in each locational deliverability area. Reliability as measured immediately prior to the Planning Year • Avoid market clearing outcomes that result in insufficient capacity and out-of-market intervention • Maintain reliability across a range of potential market conditions, while mitigating the potential for over-procurement
Prices	• Prices high enough to attract entry when needed for reliability; prices low enough to enable efficient exit and retirements during surplus • Manage price volatility due to small changes in supply and demand • Mitigate susceptibility to exercise of market power • Allow prices to move sufficiently to reflect changes in market conditions • Few outcomes at the administrative price cap
Other	• Strike a balance among competing objectives • Aim for simplicity, stability, transparency, and consensus

Source/Notes: PJM, Manual 20, Section 1.4 PJM Installed reserve Margin (IRM), 2021; Section 4.1 Overview; Newell *et. al.*, Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018.

II. Target and Realized Procurement Levels

The RPM has consistently procured capacity volumes beyond the Reliability Requirement, an outcome that produces high reliability but also higher consumer and societal costs than needed to meet the market's design objectives. The PJM Board has identified the need for "appropriate levels of capacity procurement" as a focus area for this Quadrennial Review.[6] To that end, we document the magnitude and reasons for the current levels of procurement in the RPM, and suggest RPM reforms to address stakeholder concerns of over-procurement, as summarized in Table 2.[7]

6 PJM, Board Letter Regarding Capacity Market Minimum Offer Price Rule and Initiation of the Critical Issue Fast Path Process, April 6, 2021.

7 See Consumer Advocates & Environmental Organizations, Letter Regarding Long-Term Load Forecasting, December 2, 2021; Environmental Stakeholders, Letter Regarding Phase II Capacity Market Reforms, August 8, 2021.

The largest reason for the current procurement levels has historically been an upward bias in the load forecast that has resulted in procuring excess capacity in the three-year forward auction compared to what has been needed in the Planning Year. The most appropriate response to this issue is to eliminate the upward bias in the load forecast and engage in a process of continuous improvement to the forecast; PJM has already committed to improving the accuracy of its load forecast.

We have also identified several other factors contributing to historical procurement levels. Some of these are drivers that PJM has already addressed, including eliminating the prior 1% right-shift of the VRR Curve and preventing the EE gross-up to inflate procured quantities beyond the offsetting EE resource commitments. Other drivers for procurement in excess of reliability requirements could be addressed within the scope of the RASTF, including improving the accuracy of reliability modeling and Reliability Requirement, improving capacity resource accounting, improving resource obligations and performance incentives, and explicitly accounting for winter capacity needs. We note that the effort to enhance capacity resource accounting and performance may or may not materially change the apparent volumes of capacity procurement, but will improve reliability and economic performance regardless. Further, we note that our assessment of procurement levels in the winter season remains inconclusive as to whether the winter season has excess or deficient capacity supply; we therefore highlight the importance of formalizing winter capacity accounting.

The VRR Curve can be adjusted to better achieve appropriate levels of procurement by adopting a lower and more accurate estimate of Net CONE and adjusting the shape of the curve to limit the potential for over-procurement in capacity long conditions. We see additional opportunities to right-size capacity procurement by updating the framework for supply-side EE participation to align with the load forecast and by improving transparency and consistency in reliability accounting.

TABLE 2: OPPORTUNITIES TO ACHIEVE APPROPRIATE LEVELS OF PROCUREMENT

Changes already implemented or being pursued by PJM	• Improve load forecast accuracy and eliminate over-forecast bias • Eliminate 1% right-shift of VRR Curve • Eliminate discrepancy between EE gross-up and cleared quantities
Areas in scope in the RASTF	• Determine the appropriate level of capacity procurement • Explicitly measure capacity requirements and supply commitments in winter season and more fully integrate seasonal resources • Improve capacity qualification methods and performance requirements for capacity resources
Other opportunities for improvement	• Change reference technology from CT to CC • Adopt forward-looking estimate of E&AS revenues • Adjust the VRR Curve shape to mitigate potential for excess procurement in long capacity conditions (reduce the x-axis quantity at point "C") • Explore possibility of qualifying EE as supply-side resources in the capacity market if suppliers demonstrate that the EE measures are not already accounted for in the load forecast, thereby eliminating the EE add back • Improve accounting consistency and clarity by using UCAP accounting for all purposes in RPM and seasonal reliability assessments; distinguish between supply MW with and without capacity commitments in seasonal assessments

A. Historical RPM Procurement Levels

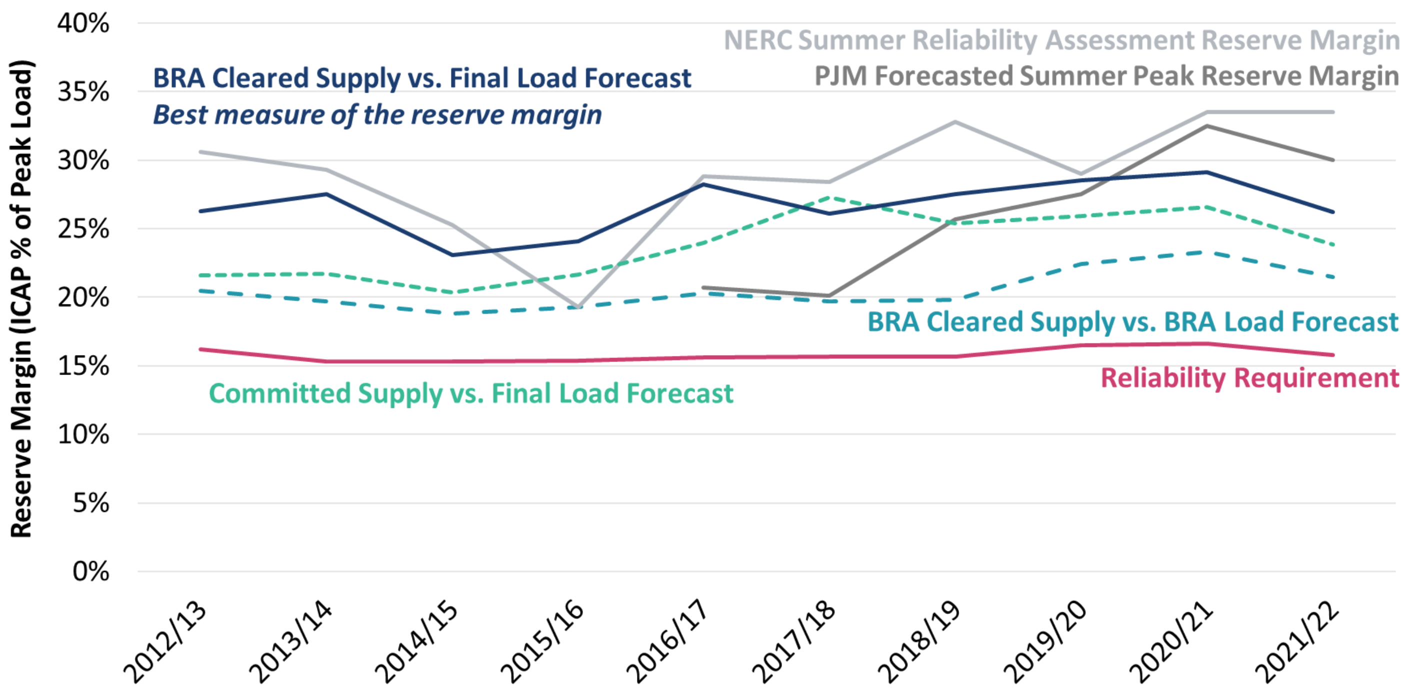
The RPM has consistently procured capacity above the Installed Reserve Margin (IRM) requirement, which has resulted in excess capacity between 9,500 MW – 11,912 ICAP MW over the most recent five Planning Years (2018/19 through 2022/23) years according to the Independent Market Monitor (IMM).[8] As illustrated in Figure 2, however, we understand that stakeholders may have multiple potential definitions of the reserve margin in mind, depending on when procured supply is measured (either as of the BRA or after the final IA) and which load forecast this supply is compared to (either the three-year forward BRA Load Forecast or the Final Load Forecast as of the Final IA). For example, the measurement of procurement levels reported

[8] Monitoring Analytics LLC, 2021 Quarterly State of the Market Report for PJM: January through September, Section 5: Capacity, November 11, 2021, Table 5-7, p. 303.

within the BRA auction results indicates reserve margins in the range of 19%-23% (compared to a 15%-16% target IRM); however the realized reserve margin prior to delivery has been higher at 23%-29% given that load growth has not been as high as was expected at the time of the BRA.

In our view, the best measure of the reserve margin is the BRA cleared supply compared to the final load forecast (the dark blue line in Figure 2) since this compares what was initially procured to the final load forecast developed three months before the Planning Year. This measures the volume of capacity paid for by consumers relative to what is needed after load forecast uncertainty has resolved.

FIGURE 2: PJM INSTALLED RESERVE MARGIN AND PROCURED AMOUNTS



Source/Notes: Reliability Requirement and BRA Load Forecast from PJM, 2012/13 to 2021/22 RPM Base Residual Auction Planning Period Parameters; BRA Cleared Supply from PJM, PJM 2022/2023 RPM Base Residual Auction Results, Table 1; Final Load Forecast from PJM, 2012/13 to 2021/22 3rd Incremental Auction Planning Period Parameters; PJM Forecasted Summer Peak Reserve Margin uses Forecasted Summer Demand from Load Forecast Report as of the Planning Year, from PJM, 2015 to 2021 Forecast Reserve Margin Graphs; NERC Summer Reliability Assessment Reserve Margin from NERC, 2012 to 2022 Summer Reliability Assessments.

An additional point of confusion is introduced by the reserve margins reported in PJM's Summer Reliability Assessment and NERC Summer Reliability Assessment reports (grey lines above), which indicate even higher reserve margins on the order of 20%-34%.[9] These Summer Reliability

[9] See PJM, 2015–2022 Forecast Reserve Margin Graphs; NERC Summer Reliability Assessment Reserve Margin from NERC, 2012–2022 Summer Reliability Assessments.

Assessment reports tend to indicate higher levels of supply availability because they include all supply on the PJM system, even if that supply does not have a capacity obligation, may retire within the Planning Year, or has capacity export obligations. Further, the accounting methods used in ICAP-based summer assessment reports are different from and less formalized than the accounting methods used for settlement purposes in the UCAP-based capacity market. To improve transparency and consistency between these approaches, we recommend that PJM adopt a unified approach to reliability accounting between the capacity market and these summer assessment reports. We recommend relying on UCAP accounting methods that are intended to offer the most accurate reflection of resources' reliability value. We further recommend clarifying the status of resources with and without capacity commitments in the reliability assessment reports.

A critical, but missing, component of our assessment relates to winter reliability. The PJM capacity market does not explicitly determine a Reliability Requirement for the winter season, and resources' UCAP MW ratings do not consider winter-specific reliability drivers (such as cold-weather-driven fuel supply and thermal outages). It is possible that the winter season may have ample supply and even higher procurement levels than summer (i.e. if the current annual resource commitments can be considered firm even in winter, which has lower peak demand). It is also possible that higher outage rates as observed in the 2014 Polar Vortex are a great concern that makes winter reliability a more substantial concern than summer.[10] PJM and stakeholders have assessed this issue in the past and implemented the current capacity performance regime as at least a partial solution. However, the RPM and reliability accounting mechanisms have not been updated to explicitly track winter needs and supply commitments. We recommend that winter capacity supply and demand should be explicitly tracked so as to clarify whether winter reliability is a substantial concern and support evaluation of updating RPM to become a seasonal construct within the parallel RASTF process.

B. Diagnosis of Capacity Procurement Beyond the Reliability Requirement

In Figure 3 we summarize the scale of impact from distinct drivers of procurement beyond the reliability requirement. We present these results for the most recent auction at the time of

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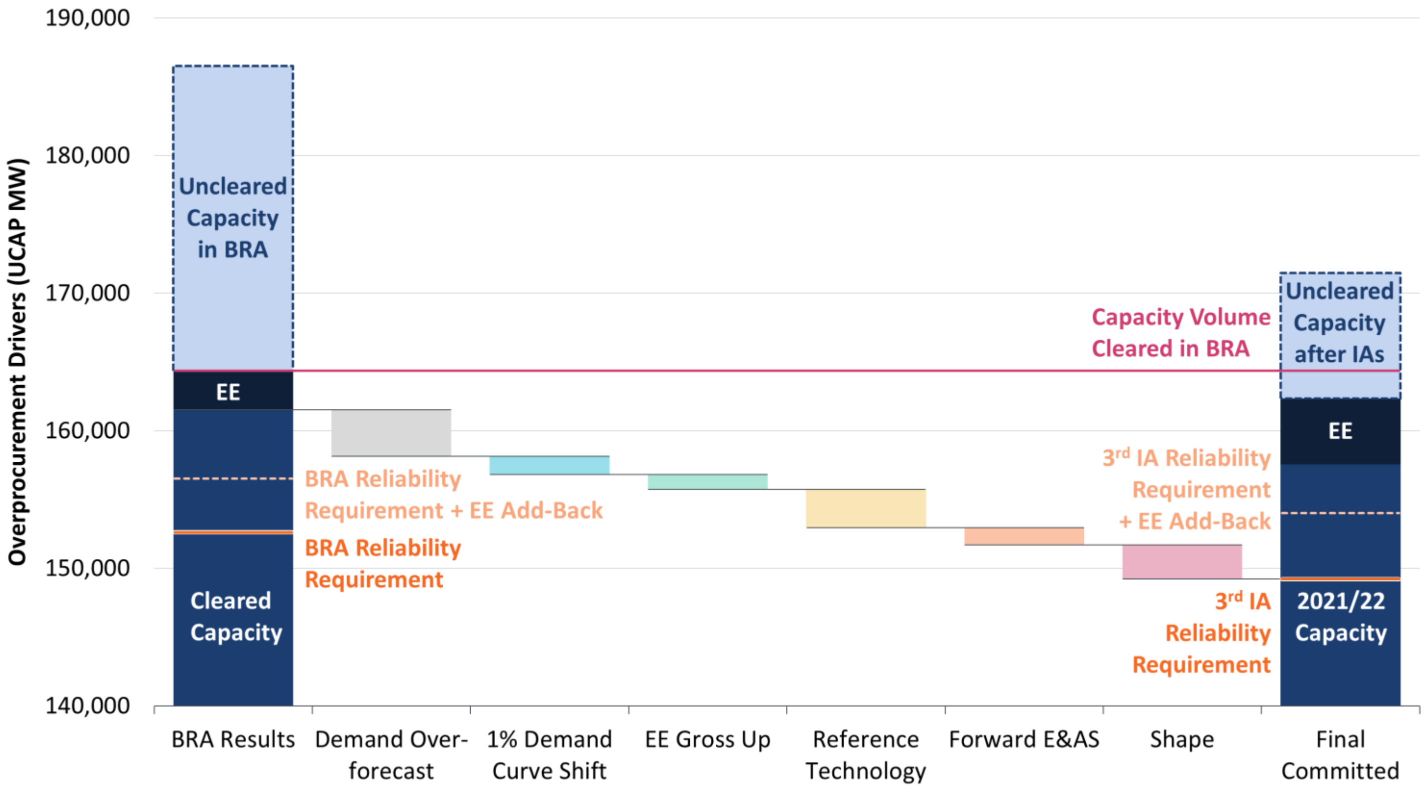
[10] During the 2014 Polar Vortex PJM faced outages of 40,200 MW or 22% of total PJM capacity. See PJM, Strengthening Reliability: An Analysis of Capacity Performance, June 20, 2018, pg. 15.

publication (2021/2022 Planning Year) noting that the relative impact of each driver has differed for each auction. The largest factor contributing to procurement beyond the reliability requirement has been a consistent over-forecasting in the load forecast.[11] However, many other factors have contributed to excess procurement within the RPM; each of these drivers will need to be addressed in a different fashion (and some have already been addressed).

FIGURE 3: DRIVERS OF OVER-PROCUREMENT (2021/22 PLANNING YEAR)



Source/Notes: Cleared Capacity, Final Committed Capacity, Uncleared Capacity, BRA and Final Reliability Requirement (adjusted for FRR), Cleared EE, Final Cleared EE from data provided by PJM; Impact of 1% Demand Curve Shift, Reference Technology, and Forward E&AS from PJM, 2021/22 BRA Planning Period Parameters, May 3, 2018 and data provided by PJM; EE Gross Up from PJM, 2021/22 RPM Base Residual Auction Results, May 23, 2018, Table 6.

The left-hand side of the chart shows BRA Cleared Capacity (blue), the Cleared EE (dark blue), and Uncleared Capacity (light blue). The far right-hand side shows the same three components of the supply stack after the final Incremental Auction. Any capacity procured above the final IA Reliability Requirement is excess relative to what is needed to meet the 1-in-10 standard. In the

[11] Our findings in this respect are generally consistent with prior work on this topic. See Public Interest and Environmental Organizations User Group (PIEOUG), Posted Meeting Materials, January 17, 2020 and James F. Wilson, Over-Procurement of Generating Capacity in PJM: Causes and Consequences, Wilson Energy Economics, prepared for Sierra Club and Natural Resources Defense Council, February 2020.

colored boxes in between, we show the impact of each factor contributing to excess procurement.

Our assessment of each driver and recommendations for how to address each contributing factor are as follows:

- **Demand Over-Forecast (grey, partially addressed):** Demand over-forecasting has been the largest single contributor to over-procurement. Beginning with the 2016 load forecast, PJM has taken measures to improve their load forecast model and address over-forecasting bias. Since then, the size of the bias has been substantially reduced.[12] However, we cannot confirm whether the bias has been eliminated, given that to date there has not been a Planning Year in which weather-normalized peak load has been under-forecasted. PJM has committed to address load forecast error and improve the forecast within the Load Analysis Subcommittee.[13] We recommend that PJM continue to address this issue though periodic load forecast improvements and independent reviews until all bias is eliminated. We also recommend to place particular focus on aligning the treatment of EE between the load forecast with the supply-side EE RPM participation model. We also recommend to re-examine the topic of forward and prompt procurement levels in light of load forecast uncertainties in future Quadrennial Reviews (see additional discussion in the following section).

- **1% Demand Curve Shift (blue, already addressed):** For several years, the VRR Curve had been implemented with a 1% right-shift compared to what we had recommended in the latest Quadrennial Review. This right-shift applied in the 2021/22 BRA depicted in this figure, but has since been eliminated. No further changes are needed to address the 1% right-shift.

- **EE Gross Up (green, partially addressed):** Under the RPM's participation model for EE, the underlying assumption is that PJM's load forecast is already accounting for all EE in the footprint. In order for EE to be incorporated as a supply-side resource in the capacity market, the demand curve is also right-shifted by the "EE add-back" or the expected UCAP MW volume of EE that is expected to clear in the auction. In the 2021/22 capacity auction however, the EE add-back was larger than the volume of EE that cleared, resulting in over-procurement. PJM has since updated its treatment of the EE add-back however, so as to iteratively adjust

12 PJM, Load Forecast Report, January 2016; average over-forecast bias between the BRA and Third IA was 9,518 UCAP MW from 2012/13 to 2016/17 but 6,681 UCAP MW between the 2017/18 to 2021/22 Planning Years; data provided by PJM.

13 PJM, Load Analysis Subcommittee.

the EE add-back and until it exactly matches and cancels out the volume of EE cleared.[14] This change will prevent one component of over-procurement as associated with the EE add-back. There is an additional concern (not pictured in the above chart) related to the EE participation model however, which is the underlying assumption that the load forecast has already accounted for all EE in the footprint. While it is not in the scope of the Quadrennial Review to conduct a comprehensive review of the load forecast, we do not believe it is a realistic expectation to require the market operator to accurately predict all EE investments that could occur throughout the PJM footprint (particularly those EE investments that may be incrementally driven by the prices and clearing results of the RPM). If the forecast under-predicts EE, this could be a contributing factor to the historical over-forecasting bias. A more realistic and self-consistent approach would be to clarify the EE assumptions within the load forecast; qualify EE measures as supply-side resources within the RPM if they will reduce consumption relative to the load forecast; maintain EE measures' capacity eligibility for the greater of the measure life or the timeframe needed to fully incorporate EE trends into the load forecast; and clear EE in the RPM in competition with other capacity supply options. This participation model would offer greater accuracy and consistency between RPM and the load forecast, allow for the elimination of the EE add-back, and eliminate the need for iterative steps in auction clearing.

- **Reference Technology (yellow, not yet addressed):** This item shows the difference in the cleared volume of capacity the VRR Curve procured (based on the current gas CT reference technology), compared to the VRR Curve if it were based on a gas CC reference technology. A CC-based curve would reduce the price parameters of the VRR curve, resulting in lower procurement volumes at a given price compared to the current CT-based curve. To improve the accuracy of the Net CONE parameter and address this driver of over-procurement, we recommend to adopt a gas CC as the system-wide reference technology, as documented in our separate Net CONE Study.[15]

- **Forward E&AS (orange, not yet implemented):** As also documented in our Net CONE Study and prior Quadrennial Reviews, we recommend to adopt a forward-looking estimation of the E&AS offset to more accurately estimate Net CONE. If a forward-looking E&AS offset had been used as of the 2021/22 BRA it would have further reduced the Net CONE, VRR Curve pricing points, and resulting procurement volumes. A forward E&AS offset will not always reduce Net

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[14] PJM Resource Adequacy Planning Department, PJM Load Forecast Report, January 2016, pg. 1.

[15] We offered the same recommendation in the last Quadrennial Review. See Newell *et.al,* Fourth Review of PJM's Variable Resource Requirement Curve, p. vii, April 19, 2018.

CONE and procurement levels; however, it can result in a higher or lower value than the current backward-looking approach. Rather, the reason to adopt a forward-looking estimate is that it is likely to be more stable and accurate. PJM has previously proposed to adopt a forward-looking approach, but FERC did not approve it for unrelated reasons. We recommend a forward-looking E&AS offset should be adopted.[16]

- **Shape (pink, not yet addressed):** A portion of the reason for procurement beyond the Reliability Requirement is associated with the downward-sloping shape of the VRR Curve, an outcome that may or may not be viewed as over-procurement depending on one's perspective. As we discuss in the remainder of this report, we assess that the potential for over-procurement under long-capacity conditions can be reduced by reducing the quantity point at point "C" in the demand curve without materially sacrificing overall VRR Curve performance. See additional discussion in Section III below.

C. Addressing Impacts of Over-Forecasting Bias

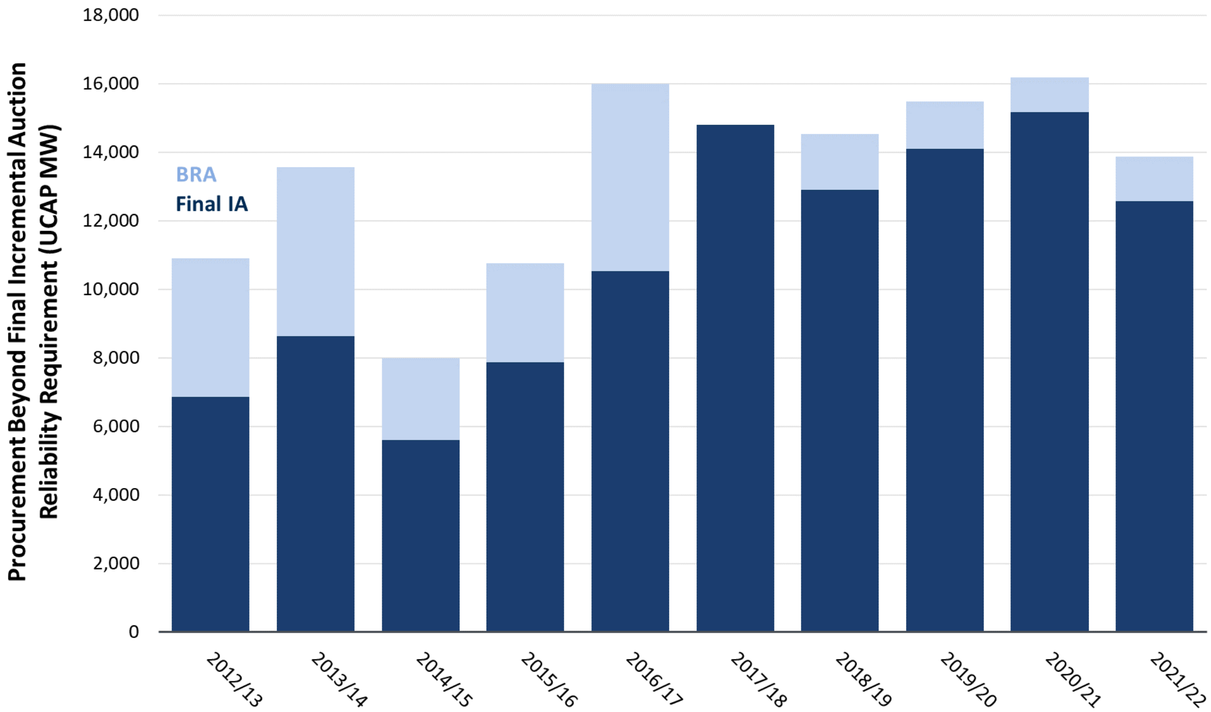
We recognize, and the RPM as a construct must anticipate, that some level of load forecast error is unavoidable. However, the construct can and should aim to eliminate any systematic bias in the load forecast. Historically in RPM, there has been an over-forecast bias, meaning that forecasted load has consistently been higher than realized demand, which has contributed to over-procurement.

Figure 4 shows the historical excess procurement for the past ten years. The dark blue is the capacity procured in excess of the Reliability Requirement of the Final IA; the light blue is the additional excess capacity that was procured in the BRA. Over-procurement has increased in recent years (as evidenced by the sum of the two bars); however, the BRA and final IA capacity procurement levels are converging (evidenced by the smaller light blue bars indicating less additional procurement in the BRA versus the final IA). This convergence is due to improved load forecasting that PJM has actively pursued. Between these improvements to the load forecast and other adjustments that PJM has made to partly address over-procurement issues (discussed in the prior section), we anticipate that the level of over-procurement will decline in coming years even if none of our additional recommendations are adopted. The three-year forward nature of

[16] The FERC identified deficiencies with portions of PJM's Operating Reserve Demand Curve filing, which had the collateral effect preventing implementation of the forward-looking E&AS offset, though the concept of the forward E&AS offset itself was not found deficient. FERC emphasizes this point in the remand order: "*As discussed below*, ***we are not determining that a forward-looking E&AS Offset is unjust and unreasonable***." Federal Energy Regulatory Commission, 177 FERC ¶ 61,209, Order on Voluntary Remand, Issued December 22, 2021, pg. 13.

the RPM and BRA creates a lag period before these improvements can materialize in the historical record.

FIGURE 4: EXCESS CLEARED CAPACITY IN BRA AND FINAL IA, ABOVE RELIABILITY REQUIREMENT AS OF THE FINAL IA



Source/Notes: BRA Cleared Capacity from PJM, 2022/23 RPM Base Residual Auction Results, Table 6, January 6, 2022; Final Incremental Auction Reliability Requirement and Final Cleared Quantity data provided by PJM.

Some stakeholders have suggested to reduce procurement levels in the BRA by the amount of historical over-forecast. This would result in buying less capacity in the forward auction and instead planning to buy more in the short-term IAs. We do not recommend to adopt this approach. If the load forecast is corrected to fully eliminate the over-forecast bias, a forecast-adjusted BRA would under-procure compared to the Reliability Requirement.[17] The more direct approach is to eliminate any bias in the load forecast, as we recommend.

Even if the load forecast is unbiased, we do see some conceptual rationale to consider incrementally shifting a portion of RPM procurement volumes from the BRA to the shorter-term

[17] An additional issue to contend with in a partial forward auction is how to update market monitoring and mitigation provisions. Requiring all supply or nearly all supply to offer into the market with a must-offer and offer cap, while incorporating only a portion of the demand in the forward auction has the potential to cause price suppression. Though this issue likely could be addressed in a mixed forward-and-prompt construct, it would require robust analysis and likely a meaningful update to the monitoring and mitigation framework.

IAs, as a possible avenue to manage the potential for over-procurement. To date, the BRA VRR Curve has been slightly right-shifted relative to the Reliability Requirement under the concept that RPM should procure enough supply to achieve a system-wide Loss of Load Event (LOLE) standard of 1-in-10 as measured at the time of the BRA. A revised approach could be to develop the VRR Curve in the BRA considering the possibility that additional capacity may be available for purchase in the subsequent IAs. The IAs would be relied upon to procure any remaining capacity needs. This approach would reduce forward procurement volumes, thereby reducing the potential cost of over-procurements in the event that the three-year foreword forecast is high. The risk of this approach however, arises in a tight capacity supply scenario in which forward procurements are low and the load forecast increases between the forward and prompt auctions. In that scenario, the IAs would need to attract additional supply offers beyond what was offered in the BRA or else the system would face a capacity shortfall.

To assess the merits of shifting demand from the BRA to subsequent IAs, we have reviewed both historical market data and model simulations. Table 3 summarizes the offered volumes in RPM BRA and IA auctions, with the far right column tabulating the Net Supply increases (or decreases, where negative) that have been offered into the IAs as compared to the BRA. If the volume of supply offered in the IA is lower than the uncleared supply from the BRA, this shows up as a negative number and indicates that supply available for purchase is contracting as the forward timeframe becomes short. Historically the IAs have shown a consistent pattern of uncleared supply from the BRA dropping out between the three-year forward BRA and the non-forward Final IA. This is logical since RPM has historically over-procured in the BRA relative to reliability needs, and uncleared resources may retire (or not build) such that they can no longer make themselves available in the non-forward auctions. Prices in the IAs have also been low and generally unattractive, likely contributing to the contraction of available supply in the IAs. Recent history shows however that approximately 53.8% of BRA Uncleared Supply has been retained and continued to offer as of the final IA.[18]

We do not yet have evidence regarding whether incremental supply would be available in the IAs under shortage conditions when the BRA has cleared with short supply and the near-term load forecast has increased. This is the primary scenario of interest however, when considering whether the RPM could shift procurement volumes from the BRA to the IA without introducing reliability risks. To maintain reliability, the prospect of increasing load forecast and a potential

[18] Here we refer to the average since the 2017/18 Planning Year after PJM implemented notable improvements in the load forecast, excluding 2018/19, which was an outlier. With the exception of the 1st IA Auction for the 2014/15 Planning Year, all Incremental Auctions since 2012/13 have resulted in negative Net Supply. See also Table 3 and the Appendix Section D.

shortfall in the IAs would need to be communicated to prospective sellers. Anticipating high prices in the IAs, sellers could then mobilize incremental supply offers that they had not offered into the BRA. If sufficient supply offers are made available in the IAs, prices may be high but reliability can be maintained. If insufficient supply offers are made available in the IAs, prices will be high but the market will clear with a shortage. We are optimistic that incremental supply could be attracted into the IAs under such a scenario, but there are no market data available to date to demonstrate this.

TABLE 3: SUPPLY OFFERED, CLEARED, AND NET SUPPLY INCREASE (DECREASE)

Year	Auction	Supply Offered			Supply Cleared			Uncleared Supply		Cumulative Uncleared Supply	Net Supply Increase (Decrease)
		Sell Offers (MW) [A] See notes	PJM Buy Bids (MW) [B] See notes	Net (MW) [C] [A]-[B]	Sell Offers (MW) [D] See notes	PJM Buy Bids (MW) [E] See notes	Net (MW) [F] [D]-[E]	Sell Offers (MW) [G] [A]-[D]	PJM Buy Bids (MW) [H] [B]-[E]	(MW) [I] [I][t-1] - [F]	(MW) [J] [A] - [I][t-1]
2017/18	BRA	178,839	n/a	178,839	167,004	n/a	167,004	11,835	n/a	11,835	n/a
	Transition	10,408	0	10,408	10,017	0	10,017	391	0	1,818	(1,426)
	1st IA	1,705	10,880	(9,175)	605	4,184	(3,579)	1,100	6,696	5,397	(113)
	2nd IA	2,842	12,223	(9,381)	1,448	4,211	(2,763)	1,394	8,012	8,160	(2,556)
	3rd IA	2,533	13,786	(11,253)	1,452	4,019	(2,567)	1,081	9,767	10,728	(5,627)
2018/19	BRA	179,891	n/a	179,891	166,837	n/a	166,837	13,054	n/a	13,054	n/a
	1st IA	16,487	9,602	6,885	2,545	2,366	180	13,942	7,236	12,875	3,433
	2nd IA	13,061	12,996	65	2,378	4,888	(2,510)	10,683	8,108	15,385	186
	3rd IA	13,109	15,712	(2,604)	4,197	4,199	(2)	8,912	11,513	15,387	(2,276)
2019/20	BRA	185,540	n/a	185,540	167,306	n/a	167,306	18,234	n/a	18,234	n/a
	1st IA	17,914	18,274	(361)	2,295	3,992	(1,697)	15,619	14,282	19,931	(320)
	2nd IA	16,891	15,329	1,562	1,613	2,294	(681)	15,279	13,036	20,612	(3,039)
	3rd IA	13,097	15,944	(2,847)	5,827	5,962	(135)	7,270	9,982	20,747	(7,514)
2020/21	BRA	183,352	n/a	183,352	165,109	n/a	165,109	18,242	n/a	18,242	n/a
	1st IA	16,413	13,372	3,041	3,554	4,326	(772)	12,859	9,046	19,014	(1,829)
	2nd IA	12,525	8,499	4,027	1,909	1,964	(55)	10,617	6,535	19,069	(6,489)
	3rd IA	10,478	11,401	(923)	3,503	4,547	(1,044)	6,975	6,854	20,114	(8,591)
2021/22	BRA	186,505	n/a	186,505	163,627	n/a	163,627	22,878	n/a	22,878	n/a
	1st IA	17,748	8,966	8,782	2,143	2,029	114	15,605	6,937	22,763	(5,129)
	2nd IA	16,755	18,021	(1,267)	3,708	6,485	(2,777)	13,047	11,537	25,541	(6,009)
	3rd IA	14,337	12,232	2,106	5,236	4,516	720	9,102	7,716	24,821	(11,203)

Sources/Notes: The 2017/18 auction cycle features a Transition Auction due to the introduction of Capacity Performance products. A negative Net Supply Increase (Decrease) [J] value indicates that the Sell Offers [A] in the current auction have decreased relative to the Cumulative Uncleared Supply from the previous auction [I][t-1], while a positive Net Supply value indicates an addition of new incremental capacity, [t -1] refers to previous auction year. Results from 2019/2020 auctions contain a mix of Base and Capacity Performance products. [A], [B], [D], & [E] from PJM, 2019/20 to 2021/22 BRA and IA Results Reports. Average Final IA Total Supply as a percent of BRA Uncleared Supply = 53.8% from years 2017/18 to 2021/22, excluding 2018/19. Calculated as: ([I][BRA] + [J][3rd IA]) / [I][BRA].

We have also conducted a simulation analysis of the potential reliability outcomes under RPM when considering the opportunity to procure capacity first from the BRA, and later through the IAs (see Appendix Section E, Table 17). In that simulation we examine reliability in a scenario with an unbiased load forecast, subject to three-year-ahead forecast error. We further assume that 53.8% of supply that was uncleared as of the BRA will remain available and offer into the IAs consistent with recent historical data. We find that our estimate of reliability is improved by accounting for the effect of the IA procurements, but this improvement is immaterial, changing from 0.73 LOLE in the BRA to 0.71 LOLE as of the final IA for the Candidate Curve. If more supply can be attracted into the IAs under shortage conditions, there could be a more notable improvement to reliability than we have estimated.

Based on this assessment, we recommend to defer until the next Quadrennial Review any further consideration of shifting procurements volumes from the BRA to the IAs. Between the changes PJM has already made and others that we recommend, we anticipate that the challenges associated with the potential for over-procurement should be largely addressed. As a result, we anticipate that the IAs will no longer be systematically oversupplied, pricing in the IAs could become more attractive, and we will have the opportunity to observe whether incremental supply can be attracted to participate in the IAs. At that time, we recommend to reconsider the question of whether and how much demand should be shifted from the BRA to the IAs to address any remaining over-procurement risks.

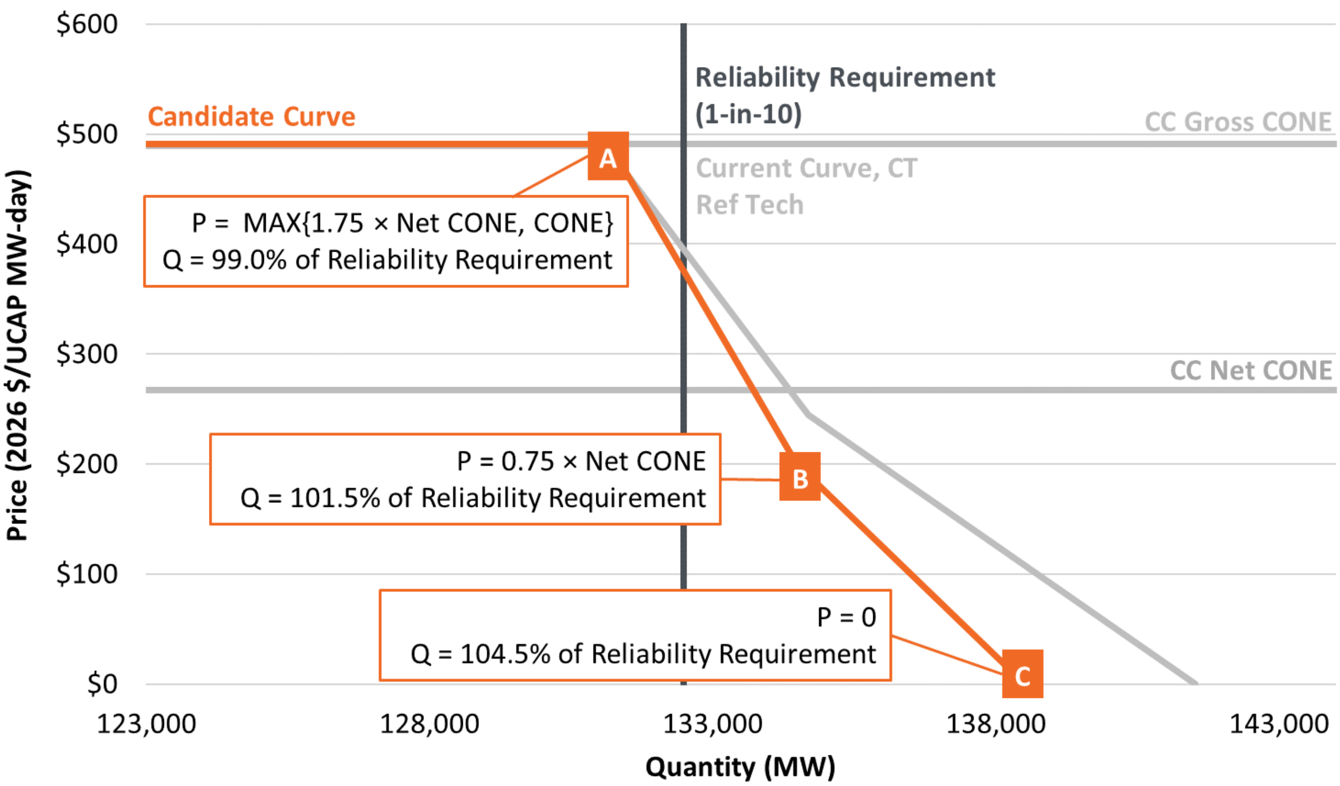
III. Evaluation of Candidate VRR Curve and Recommended Adjustments

Based on a combination of qualitative analysis and probabilistic simulations, we recommend that PJM should adopt a Candidate Curve that incorporates several adjustments relative to the current VRR curve. The Candidate Curve is a steeper kinked curve based on a gas CC reference technology with a reduced foot compared to the current VRR Curve. While we suggest a specific formula for each defined point in the Candidate Curve, we believe there is a “workable range” of curves that all would offer sufficient system reliability but with a differing balance of performance trade-offs.

A. Candidate VRR Curve

In Figure 5 we show our suggested Candidate Curve (orange) along with the formulas for creating each defined point, in comparison to the Current Curve (grey). The updated Candidate Curve would be defined based on a gas CC as the reference technology (rather than a gas CT); incorporate an adjusted formula for setting the price cap based on the greater of CONE or 1.75 × Net CONE (rather than the greater of CONE and 1.5 × Net CONE); produce a steeper kinked shape by reducing the quantity definition of Point C; and simplify the calculation of the other quantity points by referencing the UCAP-based Reliability Requirement (rather than referencing the ICAP-based IRM).

FIGURE 5: CANDIDATE VRR CURVE RECCOMMENDED TO REPLACE THE CURRENT VRR CURVE



Sources/Notes: Reliability Requirement is calculated based on UCAP Reserve Margin provided by PJM and BRA Peak Load (adjusted for FRR) from PJM, 2022/2023 RPM Base Residual Auction Planning Period Parameters, February 8, 2021; Net CONE estimates from the Brattle 2022 Net CONE Study.

The rationale for these proposed adjustments to the VRR Curve is as follows:

- **Reference Technology:** As discussed at length in our separate Net CONE Study and prior Quadrennial Reviews, we recommend to update the reference technology based on a gas CC.

- **Price Cap:** The price cap in the current VRR Curve is already defined as the maximum of Gross CONE and 1.5 × Net CONE, with the maximum serving to prevent the possibility of the demand curve collapsing to zero if administrative Net CONE would be estimated as very low or zero. We recommend to adjust the formula to the greater of Gross CONE and 1.75 × Net CONE in consideration of the substantial uncertainty in Net CONE that we perceive at the present moment.[19] As a practical matter, this change is unlikely to materially affect the VRR curve given that Gross CONE and 1.75 × Net CONE happen to be nearly identical under our current estimates. Still, the change may provide some incremental protection against the possibility of too-low pricing during short supply conditions.

- **Steeper Shape:** As seen in Figure 5, the Candidate Curve is steeper and slightly left-shifted compared to the Current Curve, achieved primarily by adjusting the foot position (Point C) to 4.5% above the Reliability Requirement. We offer this recommended adjustment to Point C based on several observations. First, we observe that under recent market conditions, the RPM has experienced a sustained long-market condition associated in part with a large turnover of the resource mix. Prices even in the "foot" region of the VRR curve have been high enough to retain existing supply and attract new supply. Reducing administrative Net CONE to a more accurate level based on a CC we expect will prevent the market from continuing to attract additional supply into an already-long market, but this may not sufficiently discipline continued going-forward investments to retain aging supply that could be allowed to retire without posing reliability problems. Put differently, the RPM has attracted large volumes of supply offers beyond what is needed for reliability and across a highly elastic supply stack; under these market conditions a relatively steep demand curve can more effectively "right-size" capacity procurements without introducing large problems with price volatility. A flatter curve is more susceptible to exacerbating current surpluses, particularly if Net CONE would be over-estimated. Our simulation results confirm these same observations (see below).

- **Simpler, UCAP-Based Quantity Formulas:** Consistent with our recommendation to simplify and improve capacity and reliability accounting by relying exclusively on a UCAP-based accounting system, we recommend to implement a simpler formula for calculating the

[19] As an example, consider a stress test scenario in which the "True" Net CONE needed to attract supply into the market is 1.4 × the administrative Net CONE used to set the demand curve. There would then be an insufficient small "buffer" of only 0.1 × Net CONE between the price cap and the long-run average price needed to attract entry. The only way to produce average prices near the long-run cost of supply would be to clear at the price cap (*i.e.*, in shortfall) approximately half of the time. This would be an unsustainable outcome and would result in administrative intervention, though we acknowledge that the scenario assumes a large error in Net CONE.

quantity points of the VRR Curve based on a straightforward percentage of the Reliability Requirement (99%, 101.5%, and 104.5% of the Reliability Requirement for Points A, B, and C, respectively).

To examine the likely performance of the Candidate Curve compared to the Current Curve, and other alternative VRR Curves, we have conducted a probabilistic simulation analysis of potential market outcomes under long-run equilibrium conditions. As described more fully in Appendix and similar to the approach used in prior Quadrennial Reviews, we conduct a Monte Carlo analysis to simulate the estimated range of price, quantity, and reliability outcomes under each VRR curve considered.

We summarize the results of this simulation analysis Table 4 and Figure 6, comparing the estimated performance of the Candidate Curve and the Current Curve. The Candidate Curve has a slightly steeper slope to mitigate over-procurement risks in the face of Net CONE uncertainty.[20] A tradeoff of a steeper slope is the slight increase in price volatility (measured in Table 4 as the standard deviation of clearing prices).

Because the Candidate Curve reduces procurement volumes, it will also produce slightly poorer reliability compared to the Current Curve. However, we estimate that both curves would outperform the 0.1 LOLE reliability standard on average, at least under our base simulation assumptions. We do see some rationale for further left-shifting the curve toward one that exactly supports the 1-in-10 standard (rather than exceeding the standard), but this would introduce other trade-offs as we discuss further in Sections III.C and III.E below.

TABLE 4: BASE CASE RESULTS OF CANDIDATE CURVE COMPARED TO CURRENT CURVE

	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Candidate Curve	$267	$85	2.7%	0.073	1,221	1.1%	10.9%	3.3%	$13,104
Current Curve, CT	$267	$74	1.5%	0.059	2,026	1.8%	7.5%	2.0%	$13,169

Source/Notes: All prices in 2026$/UCAP MW-Day and all quantities in UCAP MW; The Base Case results assesses curve performance when Administrative Net CONE is equal to the True Net CONE, whereby both are the CC Net CONE ($267/UCAP MW-Day) estimate from the Brattle 2022 Net CONE Study.

[20] We note that the Net CONE values used in our simulation analysis are slightly different from the final numbers in the 2022 Brattle Net CONE study; however, this does not materially impact our conclusions of the simulation analyses.

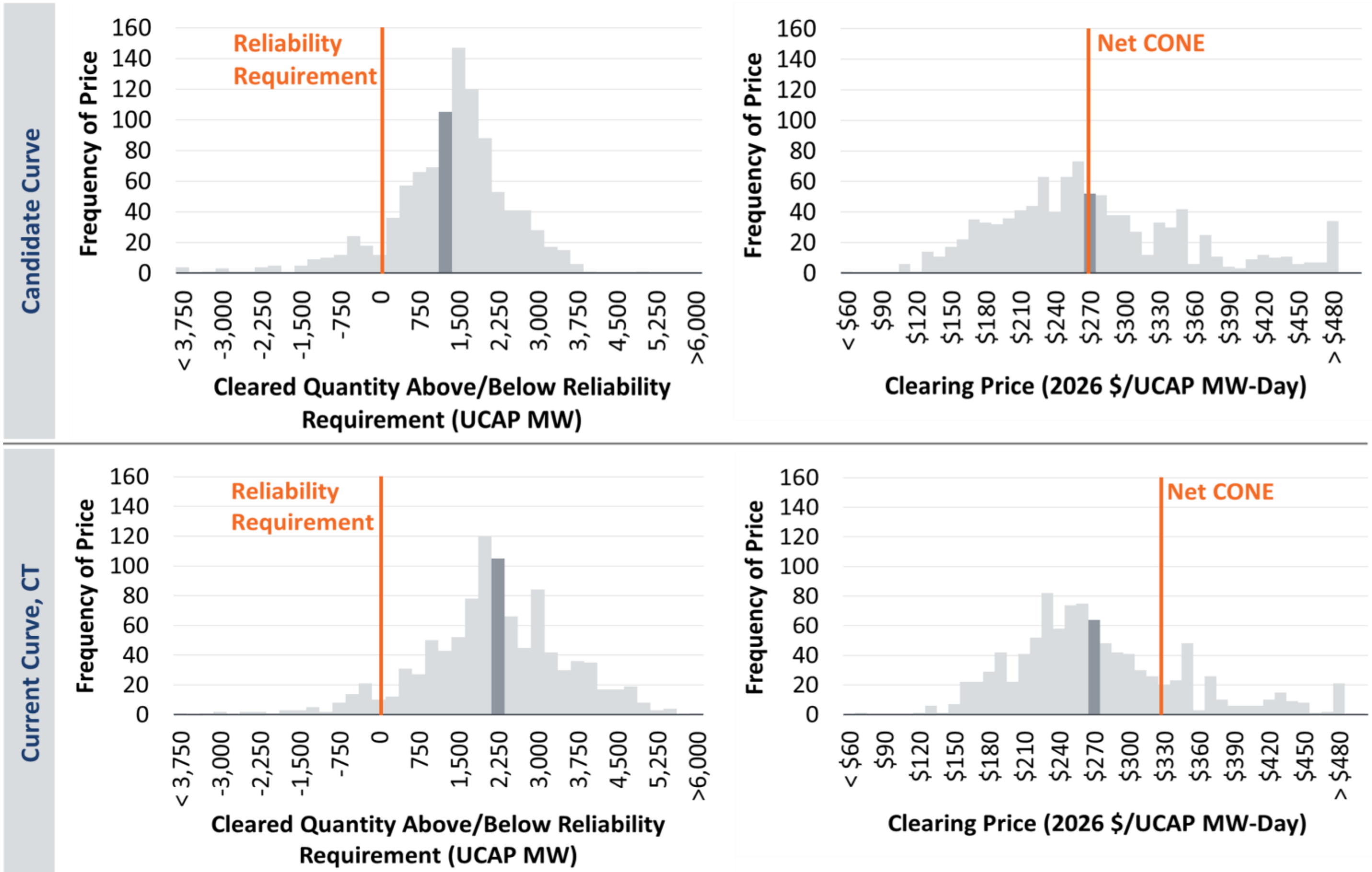
Figure 6 summarizes our estimated distributions of simulated clearing quantities and prices of the Candidate Curve and the Current Curve, CT under equilibrium market conditions. As seen on the left-hand side (Cleared Quantity Above/Below Reliability Requirement) the Current Curve, CT would over-procure by a greater volume and with a slightly greater frequency than the Candidate Curve. Furthermore, the quantity distribution of the Current Curve, CT is slightly wider, meaning that a greater window of clearing quantities would be experienced more frequently; this results in higher quantity uncertainty, as expected from a flatter curve. By comparison, the Candidate Curve has a slightly tighter quantity distribution since it is a steeper curve, thereby reducing clearing quantity uncertainty. Additionally, the Candidate Curve reduces expected procurement beyond the Reliability Requirement by 805 UCAP MW on average compared to the Current Curve, CT under our base assumptions.

On the right-hand side of Figure 6 (Clearing Price) we see the opposite effect, the Candidate Curve has a wider distribution meaning that clearing price volatility is slightly greater than the Current Curve, CT. However as seen in the figure and confirmed by the results in Table 4, the increase in price volatility for the Candidate Curve is modest, on the order of $11/UCAP MW-day. Furthermore, as we show in Figure 6 (in Section III.E below) the Candidate Curve is approximately in the middle of the range of tested curves in terms of key performance trade-offs, specifically, the clearing price volatility and expected excess procurement.

Overall, both curves produce price and quantity outcomes that are generally "workable", and without substantial concerns.[21] Overall, we view the Candidate Curve as offering improved performance compared to the Current Curve given that it reduces total procurement levels and associated costs, while still exceeding the 1-in-10 standard and offering otherwise similar performance.

[21] The problematic outcomes that we would be concerned about with a poorly performing curve include average quantities below the Reliability Requirement, high frequency of outcomes far below the Reliability Requirement, average quantities far above the Reliability Requirement, a bimodal distribution of prices, and/or a high frequency of outcomes at the price cap. Such problematic outcomes can occur with curves that are too flat, too steep, have a too-low price cap, or quantity points that far above or far below the Reliability Requirement. None of these features is present within the Current Curve or the Candidate Curve.

FIGURE 6: DISTRIBUTIONS OF CLEARED QUANTITY AND PRICE FROM THE CANDIDATE CURVE (TOP) AND THE CURRENT CURVE (BOTTOM)

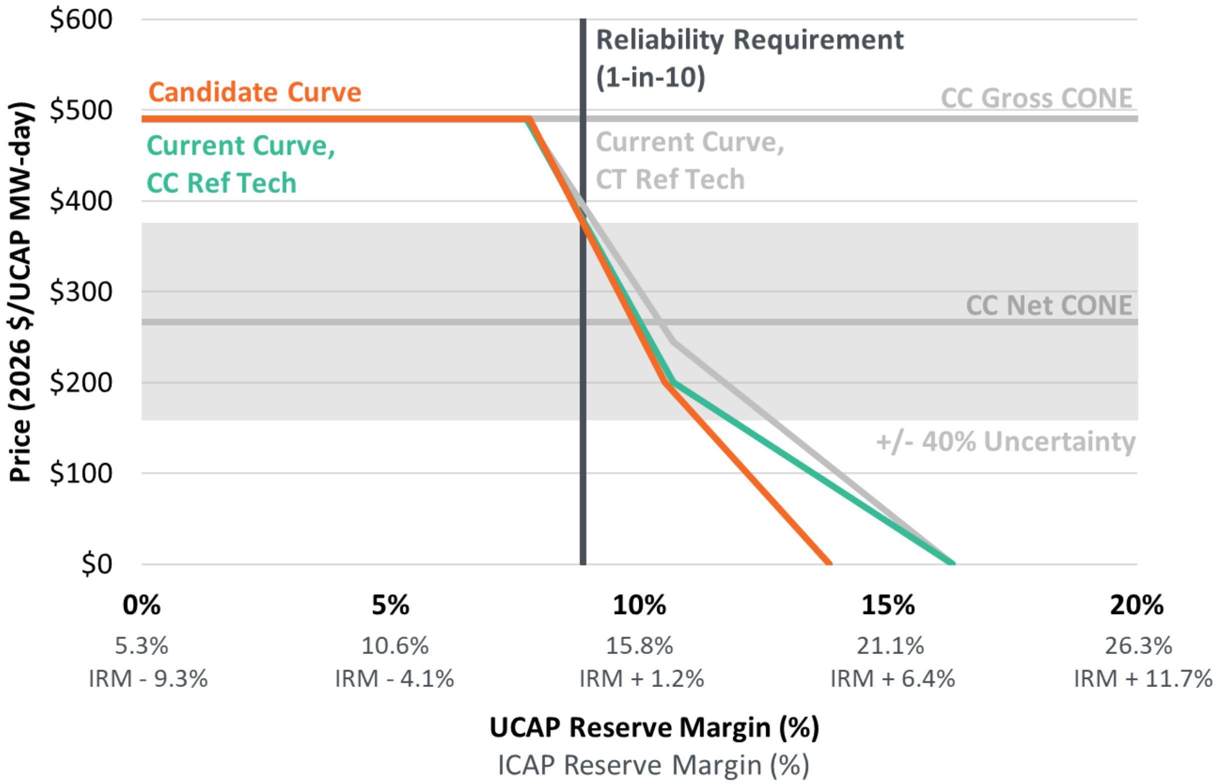


Sources/Notes: All results are generated from Base Case model run where True Net CONE is equal to CC Net CONE ($267/UCAP MW-Day); Top results are for Candidate Curve where Administrative Net CONE is equal to CC Net CONE; Bottom results are for Current Curve, CT, where Administrative Net CONE = CT Net CONE ($326/UCAP MW-Day); Histograms are reflective of results after the BRA, created from the last 1,000 model draws; Historical 2009/10 to 2022/23 RTO clearing price volatility is $48.59, calculated from PJM, 2009/10 to 2022/23 Base Residual Auction Results.

B. Performance in the Context of Net CONE Uncertainties

As discussed in our separate Net CONE Study, we perceive substantial uncertainties in administrative Net CONE under present market conditions. To evaluate the robustness of the Candidate Curve to Net CONE uncertainty, we perform stress testing equivalent to a window of ± 40% of CC Net CONE. We additionally test scenarios where the True Net CONE is a CC as we expect (the Base Case) and if the True Net CONE is instead a CT. Therefore, our stress test encompasses four scenarios in total where True Net CONE is: (1) -40% of CC Net CONE, (2) CC Net CONE, (3) CT Net CONE, and (4) +40% CC Net CONE. Figure 7 illustrates this uncertainty band in Net CONE as compared to the Candidate Curve, Current Curve with a CT as the Reference Technology, and the Current Curve with a CC as the Reference Technology.

FIGURE 7: CURRENT CURVE BASED ON CT VS CC REFERENCE TECHNOLOGY



Sources/Notes: Candidate Curve price cap at Max(1.75 × CC Net CONE, **CC CONE**); Current Curve, CC Ref Tech price cap at Max(1.5 × CC Net CONE, **CC CONE**); Current Curve, CT Ref Tech price cap at Max(**1.5 × CT Net CONE**, CT CONE), **bolded text** indicates which parameter sets the price cap for each curve.

Table 5 shows the simulated performance of these three curves across the stress test range. For the CC-based Current Curve, Gross CONE is higher than 1.5 × Net CONE meaning that the price cap (Point A) is higher relative to the target point (Point B where the kink begins). Therefore by only changing the reference technology (i.e. the Current Curve, CC Ref Tech), the resulting curve is slightly steeper. As seen in the simulation results, a consequence of changing the reference technology is a reduction in over-procurement compared to the Current Curve, CT Ref Tech. However, since the foot position would still be in the same wide position, changing the reference technology alone would not fully mitigate the potential for over-procurement. Therefore, to further address the potential for over-procurement, our recommended Candidate Curve has a reduced foot and is a slight departure from the Current Curve, CC Ref Tech. The Candidate Curve would be expected to reduce average procurement levels by 805 MW compared to the Current Curve, CT Ref Tech and by 210 MW compared to the Current Curve, CC Ref Tech in the Base Case, while still exceeding the 0.1 LOLE standard. If True Net CONE is substantially lower than the administrative estimate, the potential for over-procurement can become larger with both the CC-based and CT-based Current Curve (estimated at 3,716 MW and 4,548 MW respectively). The Candidate Curve would also produce excess procurement, but by a smaller estimated 2,026 MW.

In the event that True Net CONE is substantially higher than the administrative estimate, all curves perform worse from the perspective of estimated reliability outcomes and all produce reliability that would not meet the 1-in-10 reliability standard. That being said, all of the three curves produce reliability in the range of 0.117-0.128 LOLE (translating to a range of 1-in-8.5 to 1-in-7.8 LOLE). This level of reliability would be unacceptably poor if it were anticipated under base assumptions, but we view this as an acceptable level of risk under a stress test scenario. The curves perform similarly in this scenario due primarily to the similar placement of the price cap across the three curves (in prior Quadrennial Reviews, we have identified proper placement of the price cap as the most important factor for preventing extreme poor reliability outcomes).

TABLE 5: CANDIDATE CURVE VS CURRENT CURVE WITH CC AND CT REFERENCE TECHNOLOGIES

	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Candidate Curve									
True Net CONE = 0.6 x CC	$160	$57	0.0%	0.043	2,861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1,221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 x CC	$374	$94	21.2%	0.128	-393	-0.3%	50.0%	24.8%	$18,092
Current Curve, CT									
True Net CONE = 0.6 x CC	$160	$52	0.0%	0.026	4,548	4.0%	0.0%	0.0%	$8,029
True Net CONE = CC	**$267**	**$74**	**1.5%**	**0.059**	**2,026**	**1.8%**	**7.5%**	**2.0%**	**$13,169**
True Net CONE = CT	$326	$86	7.8%	0.085	922	0.8%	23.2%	9.0%	$15,941
True Net CONE = 1.4 x CC	$374	$87	17.9%	0.117	-25	0.0%	43.2%	20.0%	$18,133
Current Curve, CC									
True Net CONE = 0.6 x CC	$160	$52	0.0%	0.034	3,716	3.2%	0.0%	0.0%	$7,978
True Net CONE = CC	**$267**	**$81**	**2.1%**	**0.069**	**1,431**	**1.3%**	**10.0%**	**2.9%**	**$13,119**
True Net CONE = CT	$326	$92	9.3%	0.095	510	0.5%	28.8%	10.8%	$15,900
True Net CONE = 1.4 x CC	$374	$92	19.6%	0.126	-318	-0.2%	48.4%	24.4%	$18,100

Source/Notes: All prices in 2026$/UCAP MW-Day and all quantities in UCAP MW; Administrative Net CONE is equal to CC Net CONE ($267/UCAP MW-Day) for Candidate Curve, and Current Curve, CC runs above; Administrative Net CONE is equal to CT Net CONE ($326/UCAP MW-Day) for Current Curve, CT runs above.

C. Comparison to Curves "Tuned" to 1-in-10 Reliability Standard

The Current VRR Curve is anchored to the RPM Reliability Requirement and the 1-in-10 reliability standard. In prior Quadrennial Reviews, we have recommended curves (including the Current VRR curve) based on parameters that were "tuned" to achieve a 1-in-10 LOLE on average in the BRA given observed supply and demand variability. Under this approach, we have previously recommended a VRR curve that is slightly right-shifted compared to the Reliability Requirement due to: (1) the asymmetry of the LOLE curve, which means the market must remain above the Reliability Requirement more often than it falls below the Reliability Requirement in order to produce LOLE at 1-in-10 on average; (2) a price cap defined at 1.5 × Net CONE, which also would tend to require a flatter and more right-shifted curve (compared to a steeper curve with a higher price cap) in order to support reliability at 1-in-10; and (3) prior market conditions that indicated low supply elasticity around prices near Net CONE, which tended to produce more price volatility and hence a wider curve to achieve 1-in-10 and long-run equilibrium prices at estimated Net CONE.[22]

In the present Quadrennial Review, we have conducted a similar analysis to identify potential VRR curves that exactly support the 1-in-10 standard under our base assumptions. Figure 8 shows two such curves, straight line (no kink) curves with a price cap at the reliability backstop threshold and a foot at Point C that is adjusted until the curve produces an estimated LOLE of 0.1 in simulation modeling under base assumptions. In both cases, we define the price cap quantity as being fixed at near the reliability backstop threshold, which is currently defined as IRM-1%. As we have discussed in prior Quadrennial Reviews, the price cap quantity should be set at or above IRM-1%, as it represents the threshold below which PJM would consider corrective actions to ensure sufficient system capacity.[23] A well-functioning VRR Curve should limit or eliminate any need for out-of-market or corrective actions to maintain reliability, and procure all in-market capacity that has been offered before any out-of-market or backstop actions would be triggered. The curves have price caps at prices of 1.5 × Net CONE up to 1 × Gross CONE respectively, and illustrate the shape of a tuned curve would need to vary to maintain capacity procurement at the

[22] Newell, *et. al.*, Fourth Review of PJM's Variable Resource Requirement Curve, Section IV.A, April 19, 2018; and Pfeifenberger, *et. al.*, Third Triennial Review of PJM's Variable Resource Requirement Curve, Section II.C, May 15, 2014.

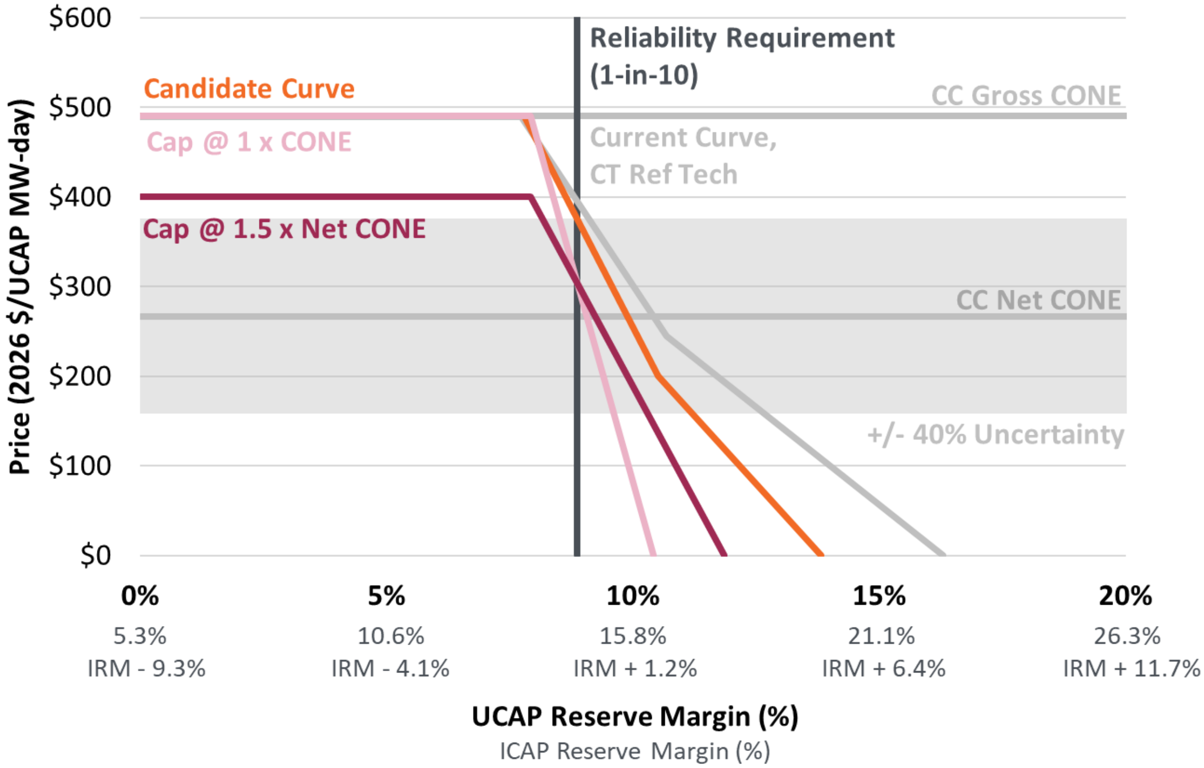
[23] As per PJM's tariff, if the RPM clears below the reliability backstop threshold three years consecutively, this would trigger a Reliability Backstop Auction; PJM, 2022 OATT, Attachment DD, Section 16.3.a.i.

1-in-10 LOLE reliability level on average. As seen in Figure 8, as the price cap increases, the demand curve foot moves to the left and the overall curve becomes steeper. Stated differently, a higher price cap allows for a steeper curve.

The 1-in-10 "turned" curves that we estimate in this Quadrennial review are substantially left-shifted compared to our findings in prior Quadrennial reviews primarily due to changes in prevailing market conditions.[24] Specifically, our updated estimate of Net CONE based on a gas CC power plant is a lower number than we have used in prior Quadrennial Reviews, and is at a price level that is within a range of the capacity supply curve with substantially greater supply elasticity. This update is consistent with observed reality that many new gas CC plants have offered into and entered into the RPM market at price levels that are intermixed with other sources of capacity supply including demand response, aging resources that may retire if they do not clear, energy efficiency, etc. Under these observed market conditions, a relatively steeper demand curve can "right-size" capacity supply every year (rather than procuring more excess in some years, so as to ensure adequate supply on average after considering yearly variability in the supply-demand balance). If these conditions persist, with ample new supply available and offering at price levels that are intermixed in a competitive fashion with existing supply, it suggests that a steeper demand curve can be adopted that will align more closely with the Reliability Requirement.

[24] The changes we discuss as driving this result all relate to the availability and cost of capacity supply. Other factors that can similarly influence this result (supply variability, demand variability, PJM's estimate of reliability vs. reserve quantity), have not materially affected the shape and placement of a tuned VRR curve as compared to prior Quadrennial Reviews.

FIGURE 8: CURVES "TUNED" TO ACHIEVE 1-IN-10 LOLE IN THE BRA



Source/Notes: Candidate Curve price cap at Max(1.75 × CC Net CONE, **CC CONE**), **bolded text** indicates which parameter sets the price cap; Cap @ 1 × CONE and Cap at 1.5 × Net CONE curves are both tuned to achieve 1-in-10 LOLE in the BRA.

Performance of these tuned curves as estimated in simulation results are shown in Table 6. Compared to the Candidate Curve, the steeper "tuned" curves reduce reliability to exactly support 0.1 LOLE, reduce average procurement levels, and reduce capacity procurement costs accordingly. The version with a higher price cap is steeper and produces higher price volatility than the Candidate Curve; the version with a lower price cap is wider produces lower price volatility. While the steeper "tuned" curve would modestly increase price volatility, the overall impact is substantially mitigated by high elasticity in the supply stack. A higher price cap is also more robust to Net CONE estimation uncertainty whereas a lower price cap is more susceptible, which could cause reliability concerns if the market clears too far below the Reliability Requirement.

Of these two tuned curves, we view the steeper curve as within the workable range of acceptable performance, particularly if recent market conditions with ample capacity supply offers remain available across a price range above and below Net CONE. However, we offer some hesitation against adopting the 1-in-10 tuned curve immediately, given that we are not confident as to whether recent market conditions (relatively lower Net CONE and greater fleet turnover than observed in prior Quadrennial Reviews) will persist indefinitely. Among other reasons, we have incorporated this analysis into our recommended Candidate Curve, which will incrementally adjust the Current VRR curve toward a curve that supports the 1-in-10 standard. In the next Quadrennial Review, we recommend revisiting this question again and considering the adoption of a curve that is exactly aligned with 1-in-10 as long as it sufficiently supports other performance objectives.

TABLE 6: PERFORMANCE OF CURVES "TUNED" TO ACHIEVE 1-IN-10 LOLE IN THE BRA

	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Candidate Curve									
True Net CONE = 0.6 x CC	$160	$57	0.0%	0.043	2,861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1,221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 x CC	$374	$94	21.2%	0.128	-393	-0.3%	50.0%	24.8%	$18,092
Current Curve, CT									
True Net CONE = 0.6 x CC	$160	$52	0.0%	0.026	4,548	4.0%	0.0%	0.0%	$8,029
True Net CONE = CC	**$267**	**$74**	**1.5%**	**0.059**	**2,026**	**1.8%**	**7.5%**	**2.0%**	**$13,169**
True Net CONE = CT	$326	$86	7.8%	0.085	922	0.8%	23.2%	9.0%	$15,941
True Net CONE = 1.4 x CC	$374	$87	17.9%	0.117	-25	0.0%	43.2%	20.0%	$18,133
Cap @ 1 x CONE									
True Net CONE = 0.6 x CC	$160	$65	0.0%	0.078	876	0.8%	1.5%	0.0%	$7,840
True Net CONE = CC	**$267**	**$98**	**5.6%**	**0.100**	**126**	**0.1%**	**29.5%**	**5.6%**	**$13,017**
True Net CONE = CT	$326	$106	14.8%	0.121	-417	-0.3%	52.2%	14.8%	$15,810
True Net CONE = 1.4 x CC	$374	$105	29.1%	0.150	-1,003	-0.8%	70.6%	29.1%	$18,024
Cap @ 1.5 x Net CONE									
True Net CONE = 0.6 x CC	$160	$60	0.0%	0.061	1,701	1.5%	0.6%	0.0%	$7,879
True Net CONE = CC	**$267**	**$75**	**9.9%**	**0.100**	**248**	**0.2%**	**31.1%**	**9.9%**	**$13,000**
True Net CONE = CT	$326	$71	32.4%	0.151	-914	-0.8%	62.0%	32.4%	$15,710
True Net CONE = 1.4 x CC	$374	$49	62.8%	0.258	-2,625	-2.2%	88.0%	62.8%	$17,746

Source/Notes: All prices in 2026$/UCAP MW-Day and all quantities in UCAP MW; Administrative Net CONE is equal to CC Net CONE ($267/UCAP MW-Day) for Candidate Curve, Cap @ 1 × CONE, and Cap @ 1.5 × Net CONE runs above; Administrative Net CONE is equal to CT Net CONE ($326/UCAP MW-Day) for Current Curve, CT runs above.

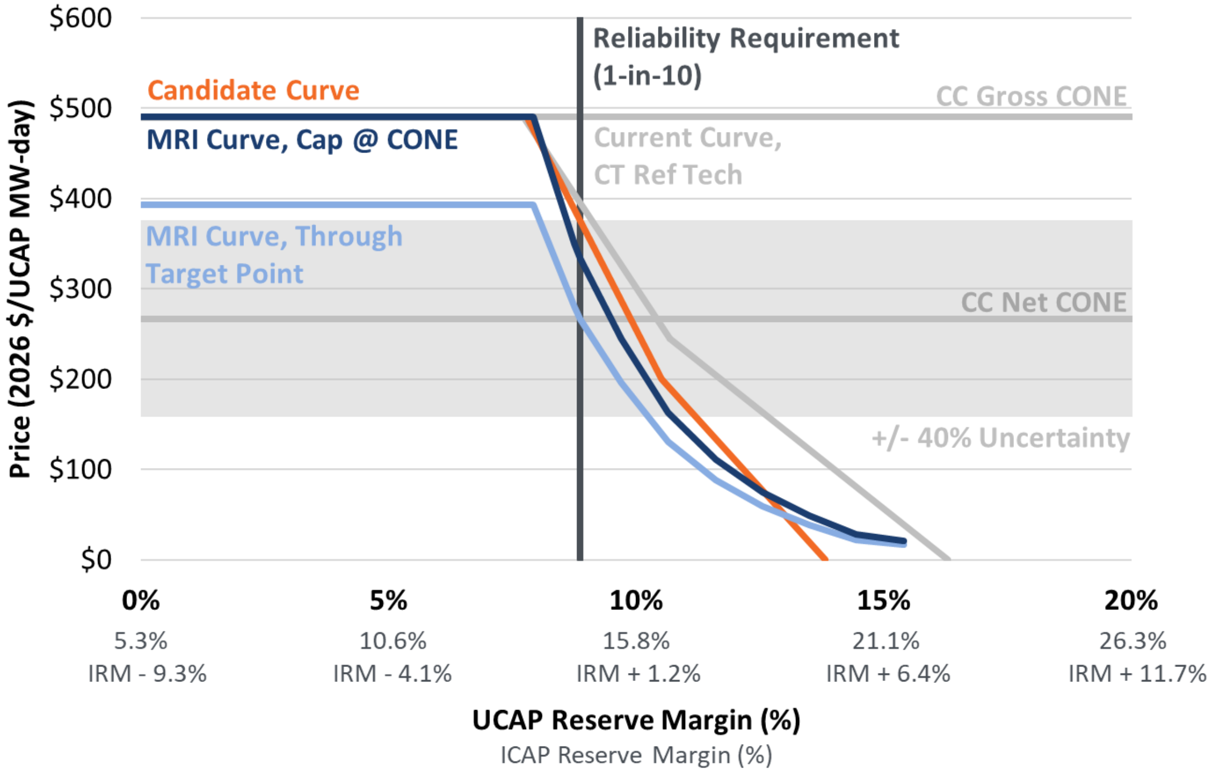
D. Comparison to Marginal Reliability Value-Based Curves

The Marginal Reliability Impact (MRI) of capacity reflects the expected improvement in reliability associated with adding incremental capacity. A demand curve constructed from the MRI would consist of price/quantity pairs such that the price at each volume of capacity is proportional to its MRI value. Under an MRI-based demand curve, prices would rise at an increasing rate as reserve margins decline to provide an increasingly strong price signal to avoid very low reliability outcomes. In a similar manner, prices decrease slowly at higher levels of reliability as reserve margins increase to reflect the diminishing, but non-zero, value of additional capacity beyond the Reliability Requirement. The primary conceptual advantage of an MRI-based curve is that all quantities on the demand curve are defined according to a consistent willingness-to-pay to avoid outage events. The MRI curve can be updated each year and used directly to calculate the parameters of a capacity demand curve, as is done in New England, or can be used more indirectly to inform the shape of the demand curve.

As shown in Figure 9, we have defined and tested two potential MRI curves, defined as: (1) an MRI curve that passes through the intersection of Net CONE and the Reliability Requirement, and at a price cap just below 1.5 × Net CONE; and (2) an MRI curve that has the price cap at Gross CONE.[25] The price cap of both curves begins where the curve quantity intersects with a quantity equivalent to the PJM reliability backstop threshold.

[25] To create these MRI-based VRR curves, we first begin with the Loss of Load Hours (LOLH) (in units of hours per year), which is one of the reliability metrics produced in PJM's annual reliability modeling study, and that is produced at each quantity of capacity (UCAP MW along the x-axis). We then adopt the assumption that 1 MW of UCAP at each quantity point, would incrementally displace the estimated LOLH times 1 MW across the year. The result is a calculation of avoided Expected Unserved Energy (EUE) per each 1 UCAP MW of capacity added to the market (in units of MWh/UCAP MW). This incremental avoided EUE can be translated into a willingness-to-pay unit for capacity ($/MW-day) via a penalty factor or value of reliability metric in units of ($/MWh). The two MRI-based curves illustrated here have two different penalty factor values, but are otherwise identical.

FIGURE 9: MARGINAL RELIABILITY IMPACT BASED CURVES



Source/Notes: Candidate Curve price cap at Max(1.75 × CC Net CONE, **CC CONE**), **bolded text** indicates which parameter sets the price cap; MRI Curve, Through Target Point passes through CC Net CONE at the Reliability Requirement and has price cap at 1.47 × CC Net CONE. Both curves have price caps where the quantity intersects with IRM-1%.

As shown in the numerical simulation results in Table 7, the MRI Curve, Through Target Point would slightly under-procure capacity relative to the 0.1 LOLE standard under the Base Case due to the lower price cap. The MRI Curve Cap @ CONE however would reduce procurement quantities while still achieving the 0.1 LOLE standard in the Base Case and result in less procurement cost on average but with an increased price volatility compared to the Candidate Curve.

Overall, we view a demand curve based on the MRI curve has a sound theoretical basis and could be a workable option that performs similarly to (or arguably better than) our recommended Candidate Curve. However, the MRI curve is based on the simulated PJM EUE reliability metric and therefore is dependent on the accuracy of the underlying reliability modeling. Given that PJM's reliability model is currently under review in the RASTF due to known deficiencies, we at the present time have only used the MRI-based curve to inform the parameters and shape of recommended Candidate Curve. We do not yet recommend to utilize these results directly in setting future VRR curves until PJM's ongoing review and enhancements to the reliability modeling are completed. Once completed within the RASTF or in future Quadrennial Reviews, we recommend that an MRI-based curve should be reviewed again and possibly considered for adoption as the basis for future VRR curves.

TABLE 7: PERFORMANCE OF CURVES BASED ON MARGINAL RELIABILITY IMPACT

	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Candidate Curve									
True Net CONE = 0.6 x CC	$160	$57	0.0%	0.043	2,861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1,221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 x CC	$374	$94	21.2%	0.128	-393	-0.3%	50.0%	24.8%	$18,092
Current Curve, CT									
True Net CONE = 0.6 x CC	$160	$52	0.0%	0.026	4,548	4.0%	0.0%	0.0%	$8,029
True Net CONE = CC	**$267**	**$74**	**1.5%**	**0.059**	**2,026**	**1.8%**	**7.5%**	**2.0%**	**$13,169**
True Net CONE = CT	$326	$86	7.8%	0.085	922	0.8%	23.2%	9.0%	$15,941
True Net CONE = 1.4 x CC	$374	$87	17.9%	0.117	-25	0.0%	43.2%	20.0%	$18,133
MRI Curve, Cap @ CONE									
True Net CONE = 0.6 x CC	$160	$56	0.0%	0.050	2,449	2.1%	0.1%	0.0%	$7,913
True Net CONE = CC	**$267**	**$88**	**4.5%**	**0.083**	**802**	**0.7%**	**18.7%**	**4.5%**	**$13,065**
True Net CONE = CT	$326	$98	12.8%	0.108	27	0.1%	42.1%	12.8%	$15,849
True Net CONE = 1.4 x CC	$374	$99	26.3%	0.139	-696	-0.6%	60.7%	26.3%	$18,056
MRI Curve, Through Target Point									
True Net CONE = 0.6 x CC	$160	$56	0.0%	0.061	1,788	1.6%	2.3%	0.0%	$7,873
True Net CONE = CC	**$267**	**$74**	**11.3%**	**0.110**	**-52**	**0.0%**	**44.0%**	**11.3%**	**$12,968**
True Net CONE = CT	$326	$69	37.0%	0.167	-1,274	-1.1%	75.9%	37.0%	$15,665
True Net CONE = 1.4 x CC	$374	$47	67.3%	0.279	-2,930	-2.5%	93.9%	67.3%	$17,699

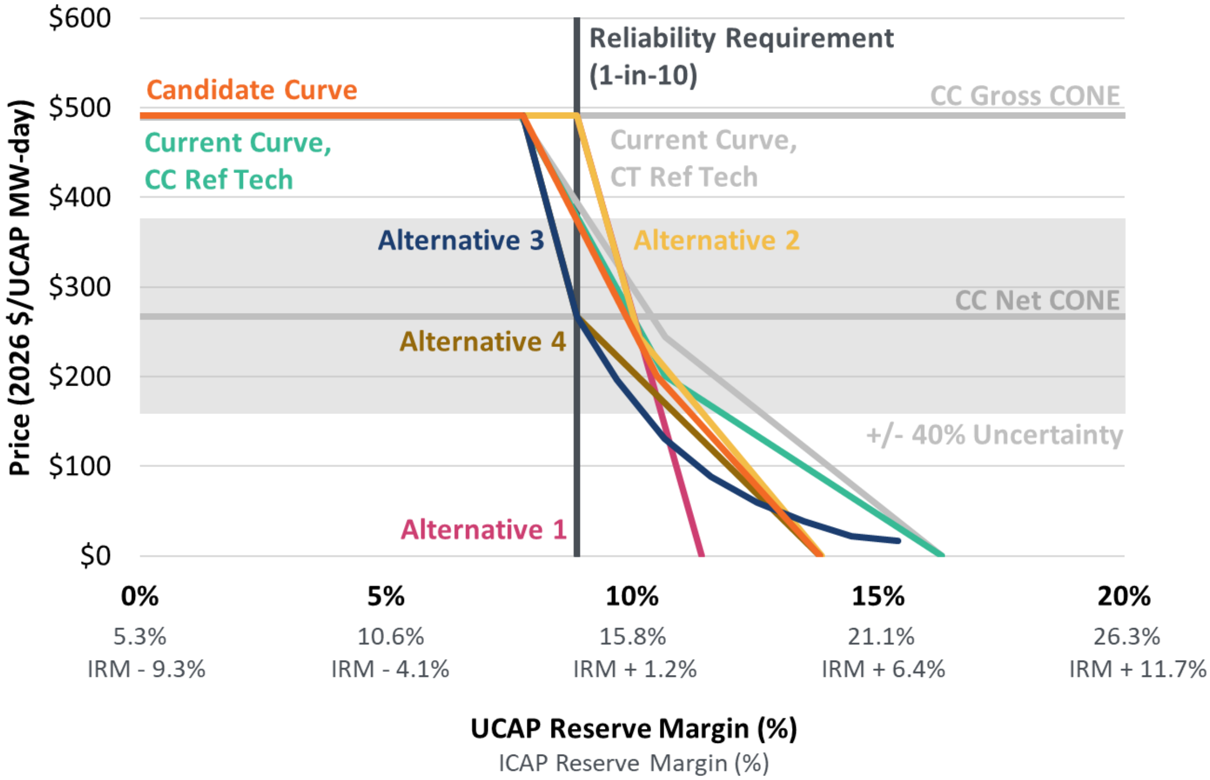
Sources/Notes: All prices in 2026$/UCAP MW-Day and all quantities in UCAP MW; Administrative Net CONE is equal to CC Net CONE ($267/UCAP MW-Day) for Candidate Curve, MRI Curve, Cap @ CONE, and MRI Curve, Through Target Point runs above; Administrative Net CONE is equal to CT Net CONE ($326/UCAP MW-Day) for Current Curve, CT runs above.

E. Comparison to Alternative VRR Curves in the Workable Range

In addition to the curves examined in the previous sections, we have also considered four Alternative Curves. Each of these curves contains features derived from one of the tested curves listed above. Additionally, the prices at the price cap for the Alterative Curves all follow the same formula for the price cap at the maximum of Gross CONE or 1.75 × Net CONE. Along with the Current Curve CT and the Current Curve, CC these Alternative Curves illustrate what we view as the “workable range” of curves (gray shaded area) previously shown in Figure 1.

In Figure 10 we show the alternative curves alongside a +/-40% Net CONE uncertainty range. Due to the inherent performance trade-offs present in designing the VRR Curve, the Alternative Curves result in a range of outcomes in terms of reliability, procurement volumes, and clearing price volatility.

FIGURE 10: ALTERNATIVE CURVES



Sources/Notes: See above for details on Alternative Curves; Current Curve, CT Ref Tech price cap at Max(**1.5 × CT Net CONE**, CT CONE), Candidate Curve, Current Curve, CC Ref Tech, and all Alternative Curve price caps at Max(1.75 × CC Net CONE, **CC CONE**); Alternatives 1 and 2 pass through CC Gross CONE at the Reliability Requirement; Alternative 3 and Alternative 4 pass through CC Net CONE at the Reliability Requirement; **bolded text** indicates which parameter sets the price cap.

Figure 11 shows the average price volatility and average excess (or deficit) across the stress test range +/-40% Net CONE uncertainty for all assessed curves. Each curve was constructed under a different concept and offers a different balance of performance trade-offs, as follows:

- **Alternative 1,** (steeper straight curve): Alternative 1 is constructed based on the tuned Curve with the Cap @ CONE (see Figure 8). As shown in Table 6 the tuned curve results in an expected reliability of exactly 0.1 LOLE when True Net CONE is equal to Administrative Net CONE, by design. However, when True Net CONE is greater than Administrative Net CONE, this curve falls short of the Reliability Requirement on average. To address this shortcoming, we move Point A to intersect with the Reliability Requirement, so the cleared quantity will only fall below the Reliability Requirement when clearing at the price cap. Point B is set so that Alternative 1 has the same slope as the tuned curve, Cap @ CONE which results in a foot position at 102.3% of the Reliability Requirement.

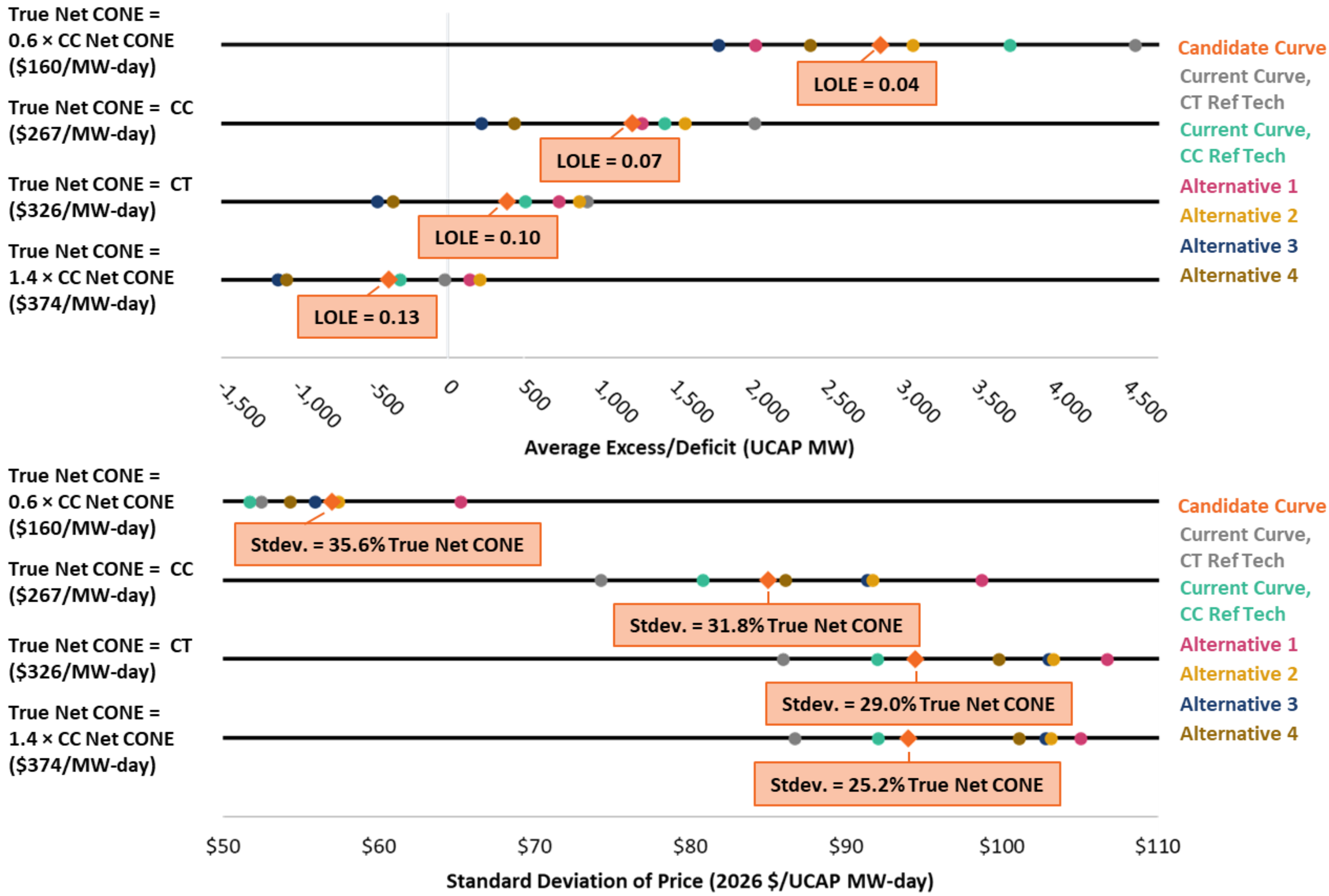
- **Alternative 2,** (steeper kinked curve): Alternative 2 has the same price cap and the same slope between point A and point B as Alternative 1. Point B is set at the same price, in $ UCAP/MW-Day, as Point B from the Current Curve, CT Ref Tech. However, Alternative 2 has a right-shifted foot compared Alternative 1 to result in a kinked curve. The foot position is set halfway between the foot position of the Current Curve, CT and Alternative 1 to result in a zero intercept at 104.6% of the Reliability Requirement. Therefore, the Alternative Curve 2 provides better protection against quantity shortfalls when Net CONE is underestimated, though it tends to over-procure more than Alternative 1 due to the kinked construction with a right-shifted foot.

- **Alternative 3,** (based on the MRI curve): Alternative 3 is straight from Point A (set at 99% of the Reliability Requirement) to Point B, which is set at the intersection of CC Net CONE and the Reliability Requirement. To the right of the target point, Alternative 3 is the MRI curve with a penalty factor chosen so that the curve passes through the target point (see "MRI curve, Through Target Point" in Figure 9). Alternative 3 results in the least excess procurement when Net CONE estimation is accurate and therefore is the closest curve to achieving an 0.1 LOLE in the Base Case. However, when Net CONE is underestimated Alternative 3 will tend to under-procure leading to potential reliability shortfalls.

- **Alternative 4,** (straight-line MRI curve): Alternative 4 is a linear approximation of Alternative 3. Points A and B are the same as Alternative 3 however the foot position is chosen to approximate the MRI curve's downward slope. This makes Alternative 4 steeper than the Candidate Curve from Point A to Point B, so it has greater price volatility but tends to over-procure less when Net CONE is overestimated. However when Net CONE is underestimated, Alternative 4 would be expected to under-procure relative to the Reliability Requirement.

The Candidate Curve falls in the middle of this range at each of the Net CONE scenarios, which is one of the reasons that we have opted to recommend the Candidate Curve as compared to these other workable alternatives. Though we do recommend the Candidate Curve as offering robust performance across a range of stress tests, we also acknowledge that these and likely other curves within the workable range could be adopted with a somewhat different balance of competing objectives. For more information on the estimated performance of the Alternative Curves, see Appendix F, Table 19.

FIGURE 11: COMPARISON OF PERFORMANCE OF ALTERNATIVE CURVES, CLEARED QUANTITY (TOP) AND PRICE VOLATILITY (BOTTOM)



Sources/Notes: 2009/10 to 2022/23 RTO clearing price volatility is $48.59, calculated from PJM, 2009/10 to 2022/23 Base Residual Auction Results.

F. Additional Considerations within Constrained LDAs

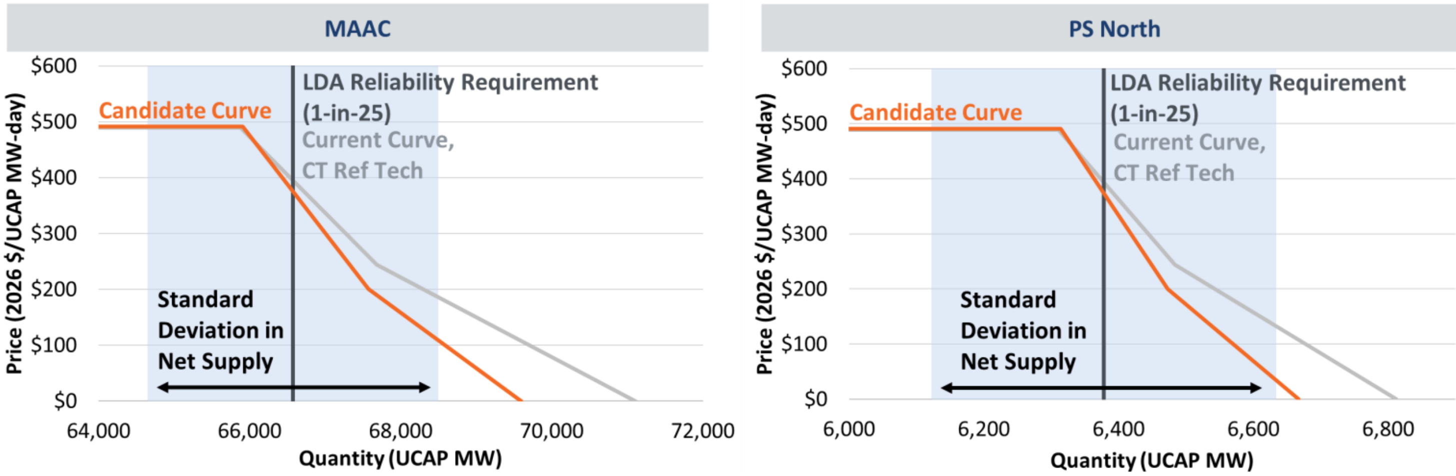
The VRR Curves for the LDAs presently use the same formula as the system-wide curve, even though LDAs are subject to distinct environments. Locational Net CONE estimation is subject to greater uncertainty and administrative error, partly driven by the use of localized E&AS revenue offsets that can be more volatile (especially under a backward-looking estimation approach). LDAs also tend to face other reliability and economic challenges that are different from the system as a whole in that they can be subject to greater capacity price volatility due to small changes in supply, demand, and transmission parameters; this volatility manifests as periodic price spikes (given that downward price volatility is buffered by parent LDAs' pricing). We have identified these same challenges in prior Quadrennial Reviews.

Managing Net CONE variability by location has always been challenging, especially among the smaller LDAs that do not have location-specific Gross CONE or E&AS estimates. Smaller LDAs can have idiosyncratic siting and land costs, differing environmental policies, or infrastructure limitations that do not apply in the larger CONE Areas. Further, these locations are unlikely to have a substantial number of projects similar to the reference unit used to estimate the Area Net CONE, limiting the available evidence that can be used to inform the LDA Net CONE and reference resource assumptions. Going forward, we anticipate that locational differences in viable reference technologies and Net CONE can become even greater as more states and local governments pursue greater environmental policies. One question we have reviewed throughout this Quadrennial Review is whether there may already be some locations within PJM where the recommended gas CC reference technology cannot be built. At this time, we have not identified regulatory or statutory limits that will prevent new fossil resources from being developed, but we anticipate that such limits could be implemented over the coming years in some locations given the substantial greenhouse gas and clean energy policy mandates already in place across the PJM footprint. We therefore recommend that PJM monitor the regulatory and statutory developments across the footprint and transition to using a clean reference technology for those LDAs if it becomes clear that gas plants cannot be built.

Managing proportionally large supply-demand variability is another reality that is more challenging across the LDAs, particularly the smallest LDAs. Figure 12 and Table 8 illustrate the scale of year-to-year supply-demand variability experienced across capacity LDAs in relationship to the size of the VRR curve. Because the same VRR Curve shape as a percentage of the Reliability Requirement is used in all LDAs, the curve becomes steeper in absolute terms in the smallest LDAs. In these locations, small increases or decreases in supply can substantially impact clearing results, even the size of a single generation plant could result in price changes from the price cap to the price floor.[26] In fact, a single 700 MW power plant has a size greater than the entire width of the LDA VRR Curve in PS-N, DPL South, PEPCO, ATSI-Cleveland, BGE, Dayton, and DEOK under the current curve parameters. Together, these characteristics increase the susceptibility of smaller LDAs to price spikes, exercise of localized market power, and proportionately large reliability challenges (or out-of-market actions to prevent reliability shortfalls) when a single large resource retires.

[26] LDAs can only clear prices at or above their parent LDA. The clearing price in the parent zone therefore acts as a soft price floor for the LDA, with the LDA price-separating above the parent only when import limits are binding.

FIGURE 12: COMPARISON OF NET SUPPLY VARIABILITY BETWEEN LARGE AND SMALL LDAS



Sources/Notes: Standard Deviation in Net Supply calculated over period 2013/14 to 2022/23; LDA Reliability Requirements from PJM, 2013/14 to 2022/23 RPM Planning Period Parameters; CONE values from 2022 Net CONE Study.

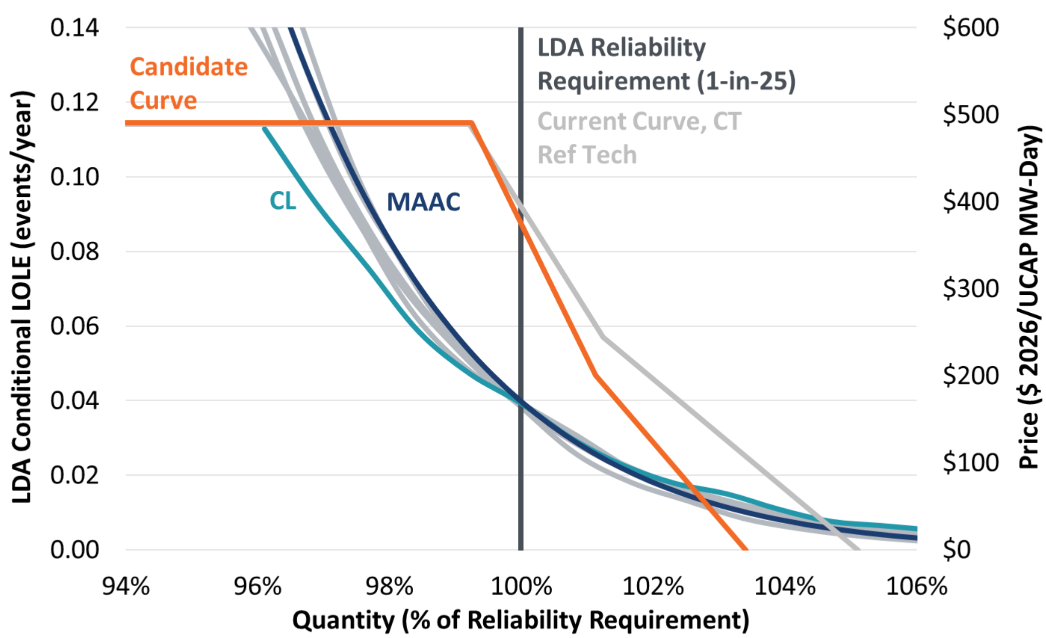
TABLE 8: LOCAL NET SUPPLY VARIABILITY COMPARED TO LOCATIONAL VRR CURVE WIDTH

	Net Supply Variability (Standard Deviation)					
LDA	Supply	CETL	Reliability Requirement	Net Supply	**Demand Curve Width**	**Net Supply Variability as Percentage of Width**
	(MW)	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(%)*
RTO	9,636	n/a	10,061	9,720	10,396	94%
MAAC	2,280	1,472	3,265	3,851	5,071	76%
EMAAC	2,260	662	1,667	2,467	2,821	87%
SWMAAC	796	985	1,030	1,958	1,174	167%
PSEG	1,351	1,001	643	864	919	94%
PS-N	611	703	215	506	486	104%
DPL-S	64	146	96	129	248	52%
PEPCO	603	959	577	1,772	605	293%
ATSI	769	1,375	410	1,481	1,180	126%
ATSI-C	202	351	329	543	453	120%
COMED	3,223	1,116	1,700	4,866	1,881	259%
BGE	435	283	384	362	615	59%
PPL	478	1,169	378	1,516	805	188%
DAYTON	200	287	39	137	311	44%
DEOK	128	266	15	242	558	43%

Sources/Notes: Standard Deviation in Net Supply calculated over period 2013/14 to 2022/23; LDA Reliability Requirements from PJM, 2013/14 to 2022/23 RPM Planning Period Parameters.

Another factor to consider when examining LDA VRR Curve is the relationship between reliability and quantity procured. PJM's local resource adequacy requirements are set based on a 1-in-25 or 0.04 *conditional* LOLE standard.[27] The LDA Reliability Standard reflects the reliability events that may be caused by location-specific shortages, which are additive to any events that may experienced due to system-wide shortages. As we show in Figure 13, the conditional LOLE curves in all currently modeled LDAs intersect with the price cap at a relatively high quantity before very poor reliability (*e.g.*, 0.1 locational LOLE) is observed, which will ensure that all in-market capacity is procured before extreme poor reliability events are observed. This relatively right-shifted price cap, combined with the 1 × CONE minimum on the price cap provide some protection against poor reliability outcomes in all of the LDAs. However, the shape of the VRR curve and pricing outcomes are otherwise disconnected from the reliability value of capacity resources in the LDAs. Capacity resources in the most constrained sub-zones have greater reliability value than capacity resources in the broader RPM footprint, but the usual outcome of RPM is that these LDAs do not produce higher prices consistent with incrementally higher reliability value (unless the LDA happens to be facing a temporary price spike and shortfall).

FIGURE 13: LDA CONDITIONAL LOLE CURVES VS THE SYSTEM-WIDE VRR CURVE



Sources/Notes: Candidate Curve price cap at Max(1.75 × CC Net CONE, **CC CONE**); Current Curve, CT Ref Tech price cap at Max(**1.5 × CT Net CONE**, CT CONE), bolded text indicates which parameter sets the price cap for each curve. Data provided by PJM.

[27] See Newell, *et. al.*, Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018, Section V.A for an in-depth description of the conditional LDA LOLE standard.

We recommend that PJM should consider locational VRR curves that are aligned with localized MRI in order to more meaningfully reflect local reliability value, manage locational supply-demand variability, reduce susceptibility to price spikes, and reduce the susceptibility to exercise of local market power. The most effective use of a local MRI curve would be combined with enhanced market clearing, following the model already in use in ISO-NE.[28] Under MRI-based VRR curves and locational clearing, an MRI curve would be calculated for the system and each LDA, reflecting the incremental value of avoided EUE achieved by adding 1 UCAP MW of capacity in each location. The system-wide MRI curve would reflect avoided EUE from reduced system-wide shortfall events, which can then be translated into units of capacity price using a value-of-reliability or penalty factor translation factor. The LDA MRI curves would be different since they would reflect the *additional* avoided EUE associated with locating capacity in a particular LDA, rather than locating that capacity elsewhere in the unconstrained system. The LDA MRI curves would then be translated into units of capacity price using the same penalty factor as used in the system curve. However, the LDA MRI curve would reflect the locational price adder to be awarded in addition to the system price, in recognition of the greater reliability value produced by resources in import-constrained locations.[29] This new MRI-based definition of local VRR would produce a flatter and lower demand curve in the LDAs, producing a more stable and modestly-sized pricing premium for locating capacity in an import-constrained region, reduced likelihood of price spikes, less susceptibility to exercise of localized market power, and pricing in alignment with differentiated reliability value. A side-benefit of redefining local VRR curves in this way is that it would simplify RPM auction clearing to eliminate the iterative steps currently required to establish LDA prices.

We recommend this approach to MRI-based LDA VRR Curves and auction clearing be reviewed for consideration in the RASTF, after PJM completes its review and enhancement to its reliability modeling framework. The enhancement of reliability modeling and MRI curves could be considered as an opportunity to align and enhance several features of the RPM including the establishment of separate summer and winter reliability requirements, separate seasonal VRR curves, LDA VRR curves, and enhanced auction clearing so as to consistently align procurement volumes and prices with reliability value.

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[28] ISO-NE, MRI Based System-wide and Zonal Sloped Demand Curves, August 25, 2016. We have also recommended similar changes in the past several Quadrennial Reviews, see Newell, *et. al.* Fourth Review of PJM's Variable Resource Requirement Curve, Section V.B.2, April 19, 2018; and Pfeifenberger, *et. al.*, Third Triennial Review of PJM's Variable Resource Requirement Curve, Section D.4 of Recommendations, May 15, 2014.

[29] This definition of the locational VRR curve pricing points is different from the definition in place in the RPM today. Local curves today reflect the absolute price that can be paid for local resources, rather than the price adder.

IV. Changing Resource Mix and Interactions with Potential RPM Reforms

The PJM Tariff identifies the scope of the Quadrennial Review as including a review of the Net CONE parameter and formula for the VRR Curve shape. In this Quadrennial Review, we have been tasked with a slightly broader scope so as to align with identified priorities and related ongoing activities of the PJM Board, OPSI, and related stakeholder initiatives, particularly those of the Resource Adequacy Senior Task Force (RASTF).[30] Though our recommendations remain mostly focused on the role of the VRR Curve within the PJM capacity market, we are acutely aware of the much more foundational transformation of the RPM that may come about as the outcome of ongoing parallel reform efforts. We also understand, and entirely agree, that foundational reforms such as those being considered in the RASTF will be necessary for the RPM to continue to maintain reliability levels, improve economic performance, align with a changing resource mix, and potentially to advance states' and consumers' resource preferences. The RPM cannot be viewed as a static construct, but rather one that must be updated over time to maintain relevance throughout industry transition.

Conducting this independent review of the VRR Curve has presented new challenges given the context of fleet transition and the large uncertainties regarding potential reforms to the broader PJM market. The VRR Curve that PJM adopts upon conclusion of this review is scheduled to be implemented in the market for Planning Years 2026/27 to 2029/30, a timeframe over which nearly every aspect of the RPM has the potential to be at least adjusted and in some cases substantially reformed. Table 9 provides a summary of the key work activities currently underway within the RASTF and scheduled for completion throughout 2023 (a timeframe that extends beyond the Fall 2022 deadline for PJM to file any VRR Curve updates with the FERC). Many of the potential RPM reforms may have limited interactions with the demand curve shape, and would require nothing more than a double-check to ensure alignment or a refinement to the administrative Net CONE estimate. Other reforms, such as adopting a seasonal capacity market, likely would require revisiting the question of the VRR Curve shape entirely. We summarize our initial sense of these potential interactions below, but note that we are unable to provide a complete assessment without having a clearer picture of the specific reforms that will be implemented.

[30] See PJM, PJM Board of Managers; Organization of PJM States (OPSI); and Resource Adequacy Senior Task Force.

TABLE 9: INTERACTIONS BETWEEN VRR CURVE AND KEY WORK ACTIVITIES OF THE ONGOING PJM RESOURCE ADEQUACY SENIOR TASK FORCE

Key Work Activity	Potential Interactions with VRR Curve
1. Determine whether a forward procurement of clean resource attributes should be pursued, and investigate the inclusion of the Social Cost of Carbon in PJM	• Incorporating the Social Cost of Carbon would pose **modest interactions** and would require updating the Net CONE estimate • Forward clean energy or capacity attribute procurements could pose anywhere from **modest to large interactions** depending on the scope of reforms. An entirely separate clean energy attributes market may pose minimal interactions with the current VRR Curve; but a fully integrated clean energy/capacity market could introduce substantial interactions and may require a new demand curve or constraint to be defined for the new product(s)
2. Determine the types of reliability risks and risk drivers the capacty market should consider and how they should be accounted for	• Improved reliability assessments can more accurately determine the quantity placement of the VRR Curve and can inform the VRR Curve shape in future reviews, but will have otherwise **minimal interactions** • If a seasonal capacity market is adopted, the **VRR Curve likely would need to be considered afresh** with the possibility of different interpretations of the Reliability Requirement reference technologies, Net CONE values, and parameters in each season. Similarly, other new/segmented capacity products could also require a fresh look at the VRR Curve
3. Determine the desired procurement metric and level to maintain the desired level of reliability	• Similar to #2, **minimal interactions** unless this also introduces changes to the number of distinct capacity products (e.g. seasonal capacity commitments)
4. Determine the performance expected from a capacity resource	• May require an update to the Net CONE estimate, otherwise **modest interactions**
5. Determine the qualification and accreditation of capacity resources	• May require an update to the Net CONE estimate, otherwise **modest interactions**
6. Determine the desired obligations of capacity resources	• Seasonal market would require **a fresh VRR Curve review** (see #2). May require an update to the Net CONE estimate
7. Determine if there are needed enhancements to the capacity procurement process	• **Unclear interactions** until potential reforms are more fully specified • To enhance performance with VRR Curve we recommend updating optimized auction clearing to remove iterative and heuristic steps, and to incorporate MRI concepts into locational clearing and price formation
8. As applicable, determine any remaining design details for a seasonal capacity market construct not addressed in other key work activities	• If a seasonal market is implemented, **a fresh look at the VRR Curve** likely would be required for each defined season
9. Determine if supply-side market power mitigation rules in the capacity market need to be enhanced	• Based on sensitivity testing reported in the Appendix, we anticipate **modest interactions** between VRR Curve performance and adjustments to the mitigation framework
10. Determine if the FRR rules need to be synchronized with any changes made	• **Modest interactions** unless the scale of implications for year-to-year changes in RPM cleared market size becomes much larger

Among these reforms, we highlight the possibility of a seasonal capacity market (key work activities 2, 3, 6, and 8) as having a large interaction with the VRR Curve, and likely requiring a fresh look at the VRR Curve shape once the basic construct for the seasonal market (number of seasons, nature of procurement) is identified. One variation of a seasonal capacity market would require a demand curve to be determined for each defined season, which would have its own capacity product and supply/demand accounting. Under such a seasonal design, it may be necessary to define separate reference technologies, separate Net CONE parameters, separate Reliability Requirements, and otherwise examine the VRR Curve parameters for each season.

Related to clean resource attributes procurement (key work activity 1), we note that there is the potential to require substantial VRR Curve reforms, but the topic is not sufficiently explored to evaluate the scope of interactions. We do offer a recommendation to continue developing PJM's capability to accurately estimate the Net CONE of clean resources, denominated in both clean energy attribute (e.g. \$/MWh and/or \$/REC terms) and in capacity (e.g. \$/MW-day) terms in order to improve the accuracy of the parameters. A clean resource Net CONE parameter may be required in any case if there are LDAs where new fossil supply will eventually not be possible to be developed and may eventually be needed for use in a regional clean energy/capacity market construct.

Related to procurement processes (key work activity 7), again the activity is not yet sufficiently defined to evaluate the scope of interactions. That being said, we offer several recommendations here for how the RPM procurement process could be enhanced to improve the relevance and performance of the system and locational VRR Curves (also touched on in prior sections of this report). We recommend to eliminate all iterative and heuristic steps from capacity market clearing, and replace them with optimized clearing. As of now, iterative/heuristic steps are used for seasonal resource matching, locational clearing, and matching cleared EE with the volume of the EE gross up. Each of these iterative clearing processes can be improved by replacing them with a simpler one-step optimization; as relevant examples for how this can be done we point to Ontario's seasonal two-season optimized capacity market clearing, ISO-NE's MRI-aligned locational market clearing approach (see Section III.D above), and recommend using an entirely supply-side EE accounting approach (see Section II.C above).[31] Auction clearing in the Incremental Auctions can also be simplified and clarified by using a "gross clearing" rather than a "net clearing" approach, with all existing capacity commitments pre-scheduled into the auction

[31] See Ontario's two season (summer/winter) capacity market IESO, Capacity Auction, and ISO-NE's MRI locational clearing approach, ISO-NE, MRI Based System-wide and Zonal Sloped Demand Curves, August 25, 2016.

clearing.[32] Simplifying auction clearing will improve transparency, enhance optimized resource selection, and refine pricing signals, especially for signalling seasonal and locational capacity needs. A simpler auction clearing platform that eliminates iterative/heuristic steps will also create a more robust framework that can be used to layer on new products or constraints should the need be identified.

As a final observation related to the ongoing fleet transformation and RPM reform efforts, we note that the scope of the Quadrennial Review is relatively limited compared to the scope of reforms that could be needed over the coming decades. Some of the challenges and issues that have been identified by stakeholders in the QER process cannot be meaningfully addressed via changes to the VRR Curve shape or parameters. The scope of the RASTF, on the other hand, is quite broad and therefore has the potential to produce the range of enhancements needed to improve the performance and sustainability of the capacity market. Even after the present RASTF process is concluded, there is a possibility that additional ongoing refinements could be needed over the coming date throughout fleet transition. If it is determined that a regularized process for RPM reform updates would be helpful, one option would be to broaden the scope of future Quadrennial Reviews (e.g. starting with Planning Years 2030/31 to 2033/34).

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[32] The current approach to incremental auction clearing uses a "net clearing" approach that aims to clear only residual capacity needs (or release excess capacity), recognizing only a limited portion of the system and locational VRR Curves; the IAs also recognize only a portion of the system's capacity transmission capability. This approach to IA clearing has the potential to under-utilize the transmission system, and (at least in our view) reduces the transparency of the IAs. A simplified gross IA clearing approach would account for all supply (including supply already committed and not yet committed), all portions of all demand curves as updated with the latest load forecast, and all transmission capability. Any capacity supplies already committed would be pre-scheduled into the clearing so that the volumes could be accounted for in auction clearing, but these resources would not have any financial implications. Incremental and decremental supply/demand bids would then be determined to clear optimally against the IA price and in full use of the transmission system. This gross clearing model would be more analogous to how the real-time energy market is cleared, and is largely the same as the model that the Midcontinent ISO uses to clear its locational capacity auction in consideration of the capacity obligation commitments that are made largely in advance of the auction (and that therefore are accounted for in auction clearing even though they do not "clear" that auction). See MISO, Business Practices Manual: Resource Adequacy (BPM 011: Resource Adequacy), Sections 5.3 and 5.5.

List of Abbreviations

A/S	Ancillary Service
ATSI-Cleveland	American Transmission Systems, Inc.-Cleveland
BGE	Baltimore Gas and Electric
BRA	Base Residual Auction
CC	Combined Cycle
CETL	Capacity Emergency Transfer Limit
ComEd	Commonwealth Edison, Exelon Corporation
CONE	Cost of New Entry
CT	Combustion Turbine
CP	Capacity Performance
Dayton	Dayton Power and Light Company
DEOK	Duke Energy Ohio/Kentucky
DPL South	South Delmarva Power and Light-South
DR	Demand Response
E&AS	Energy and Ancillary Services
EE	Energy Efficiency
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FPR	Forecast Pool Requirement
FRR	Fixed Resource Requirement
IA	Incremental Auction
ICAP	Installed Capacity
IMM	Independent Market Monitor
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kWh	Kilowatt Hours
LDA	Locational Deliverability Area
LOLE	Loss of Load Event
MAAC	Mid-Atlantic Area Council
MISO	Midcontinent Independent System Operator
MOPR	Minimum Offer Price Rule
MRI	Marginal Reliability Impact
MW	Megawatts

MWh	Megawatt Hours
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
PEPCO	Potomac Electric Power Company
PJM	PJM Interconnection, LLC
PPL	Pennsylvania Power and Light Company
PS-N	North Public Service Enterprise Group-North
PSEG	Public Service Enterprise Group
RASTF	Resource Adequacy Senior Taskforce
Ref Tech	Reference Technology
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
UCAP	Unforced Capacity
VOM	Variable Operations and Maintenance
VRR	Variable Resource Requirement

Appendix: Detailed Modeling Assumptions and Approach

In this Appendix we provide additional detail on the structure and input assumptions for the probabilistic Monte Carlo simulation modeling, utilized to examine performance of a range of VRR Curves. Additionally, we provide the results of additional sensitivity analyses to illustrate the sensitivity of model results to our input assumptions and modeling approach.

A. Overview of Model Structure and Assumptions

To evaluate PJM's current VRR Curve and possible alternative curves, we conducted Monte Carlo simulations using an updated and enhanced version of the model used in the 2018 review.[33] This analysis allows us to estimate distributions of price, quantity, and reliability outcomes under a particular VRR Curve, and review these outcomes in light of the performance objectives of the VRR Curve and RPM. Though we continue to focus primarily on the estimated outcomes in the three-year-forward BRA, we have also updated the model to account for supply and demand uncertainties that unfold after the BRA and before the Planning Year begins.

The Monte Carlo simulation model we employ in this analysis evaluates capacity market outcomes probabilistically, given realistic variability in supply and demand in both the forward and prompt periods, and under the long-run equilibrium assumption that merchant generation will enter the market until average prices equal Net CONE. Due to unavoidable variability in supply-demand conditions, it is not possible to ensure that procured capacity will land exactly at the Reliability Requirement in every year. We therefore simulate a distribution of cleared reserve margins produced by the capacity market, and evaluate how a demand curve performs. Given our assumption of economically rational new entry, our simulations reflect long-term economic equilibrium conditions and average performance of tested curves, and do not reflect a forecast of outcomes over the next several years or any particular year.

We use historical market data to calibrate the size and standard deviations of supply and demand; every input parameter utilized in the model is derived directly from auction parameters, historical market data, and historical offer prices. By ensuring that all model inputs and parameters are derived directly from observable data, we aim to improve the accuracy and validity of modeling results and minimize the importance of subjective judgements.

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[33] See Newell, *et. al.*, Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018.

Figure 14 shows a stylized depiction of how the model estimates a distribution of price and quantity distributions driven by supply and demand variability. We derive parameters causing supply and demand variability from the historical variation of supply and demand in the BRA and IA, using data from the 2013/14 to 2021/22 Planning Years. For each model draw, the model chooses one supply curve (with quantity represented as a percent of BRA total supply) from the range of normalized and smoothed supply curves. On the demand side, the VRR Curve is calculated relative to the Reliability Requirement, which is subject to variability in each model draw. The intersection of supply and demand determines the clearing price, quantity, and reliability in each draw. These clearing results as tabulated across many draws provide the estimated distribution of market clearing results. The shape of the demand curve under consideration will result in different price and quantity distributions compared to other tested curves. To simulate rational economic entry and exit, we modify the quantity of BRA total supply offered into the market such that average prices across 1,000 distinct simulated draws in the market converge to an equilibrium price at Net CONE.[34]

[34] We utilize a "smart block" in the supply curve that grows or contracts as needed to achieve pricing convergence at Net CONE. Pricing convergence is achieved in the first 9,000 draws of the model. After the model converges, the model begins tabulating price, quantity, and reliability outcomes across another 1,000 draws. We report the results from these final 1,000 draws throughout this study. Differently-shaped demand curves will result in different average cleared quantities and average performance metrics. This Monte Carlo approach allows us to examine the performance of each candidate VRR Curve in a long-term equilibrium state under total expected variability in supply and demand.

FIGURE 14: ILLUSTRATION OF CLEARING OUTCOMES ACROSS MODELING DRAWS

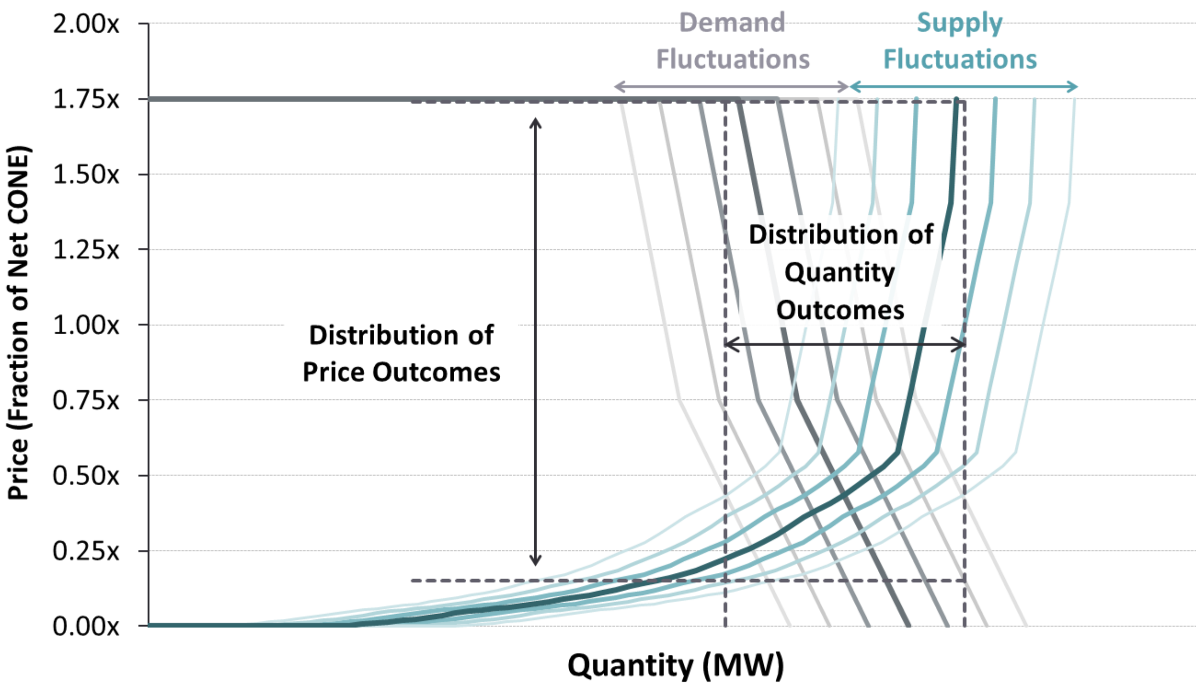


Table 10 summarizes the Base Case input assumptions. We detail the derivation of each parameter in its respective sub-sections in the Appendix. Most modeling inputs such as system peak load are consistent with the 2022/23 BRA Planning Period Parameters, whereas Gross and Net CONE values are from the concurrently released 2022 Net CONE Study.[35]

[35] There are slight differences in Gross and Net CONE parameters between this study and the Net CONE Study due to ongoing refinements of the Net CONE parameters. We anticipate these refinements may continue throughout an ongoing PJM and stakeholder engagement process; however, we have recommended a Candidate VRR Curve that will offer strong performance over a large uncertainty range in Net CONE and Gross CONE parameters.

TABLE 10: BASE CASE INPUT ASSUMPTIONS

Parameter	Unit	Value
PJM System Parameters		
Peak Load	(MW)	121,693
Forecast Pool Requirement	(UCAP %)	8.9%
Reliability Requirement	(UCAP MW)	132,495
Net CONE		
CC Net CONE	($2026/MW-day)	$267
CC Gross CONE	($2026/MW-day)	$491
CT Net CONE	($2026/MW-day)	$326
CT Gross CONE	($2026/MW-day)	$408
Supply and Demand Variability		
BRA Total Supply	(Std. Dev as % of BRA Total Supply)	3.2%
BRA Reliability Requirement	(Std. Dev as % of BRA Reliability Requirement)	4.1%
Forward-to-Prompt Supply	(Std. Dev as % of BRA Total Supply)	1.0%
Forward-to-Prompt Reliability Requirement	(Std. Dev as % of Final IA Reliability Requirement)	1.7%
Incremental Auction		
IA Available Supply	(% of BRA Uncleared Supply)	53.8%
Capacity Released in IA	(% of Target Quantity)	50.0%
Minimum Supply Offered in IA	(MW)	1,000

Sources/Notes: BRA Reliability Requirement and Peak Load are adjusted for FRR; Peak Load from PJM, 2022/23 Base Residual Auction Planning Period Parameters; UCAP Reserve Margin provided by PJM; CONE values from Brattle 2022 Net CONE Study; IA data and Variability calculations based on historical deviation from trend, data from PJM, 2013/14 to 2021/22 Base Residual Auction Planning Parameters, PJM, 2013/14 to 2021/22 Base Residual Auction Results, and PJM, 2013/14 to 2021/22 RPM Incremental Auction Results.

B. Demand and Reliability

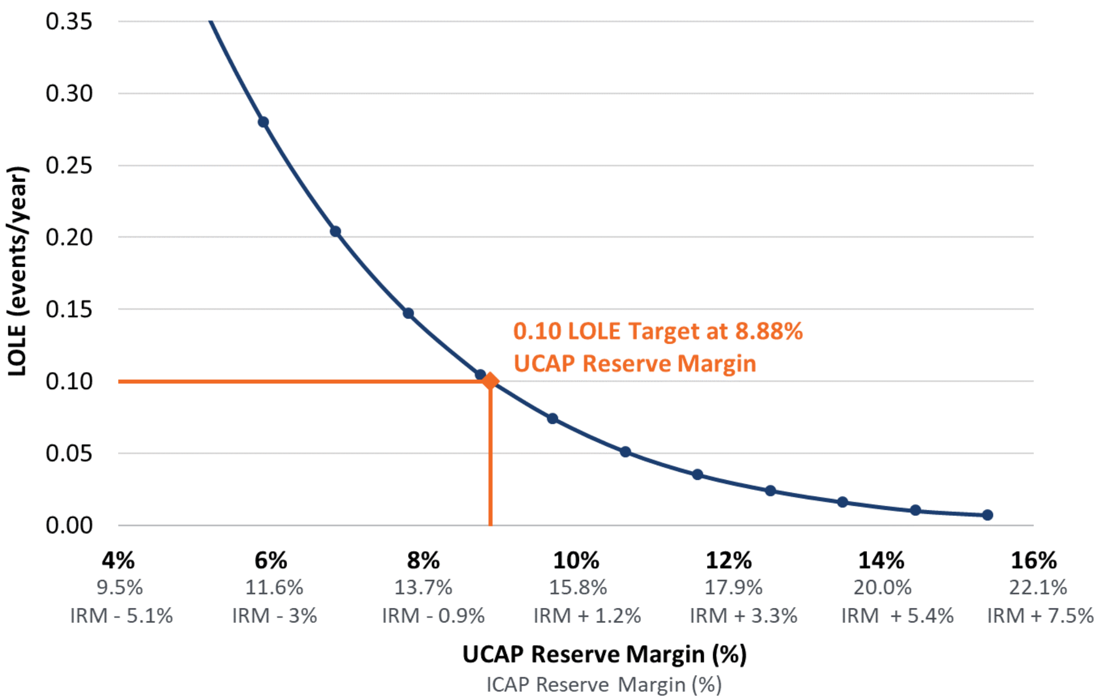
Demand parameters summarized in Table 10 are consistent with the 2022/23 Base Residual Auction, and exclude demand associated with FRR entities.[36] We estimate reliability outcomes from the cleared UCAP reserve margin in each draw.[37] Figure 15 shows the relationship between LOLE and cleared quantity as estimated by PJM staff in the most recent reliability study. This relationship is asymmetrical, with LOLE increasing more steeply (indicating worsening reliability outcomes) below the Reliability Requirement but with LOLE decreasing more gradually (meaning improving reliability) at reserve margins above the Reliability Requirement. An implication of this

[36] PJM, 2022/23 Base Residual Auction Planning Period Parameters, February 8, 2021.

[37] In our analyses, the average LOLE reported for a given demand curve is calculated as the average of the LOLE at the cleared reserve margin in each individual draw, rather than the LOLE at the average cleared reserve margin across all draws.

asymmetry is that a demand curve that results in a distribution of clearing outcomes centered on the Target Point (i.e. the Reliability Requirement) with equal variance above and below the target will fall short of the 0.1 LOLE target on an average basis.

FIGURE 15: LOSS OF LOAD EVENTS VS UCAP RESERVE MARGIN



Sources/notes: LOLE at each quantity point were estimated by PJM reliability modeling staff.

In each model draw, the Reliability Requirement is updated after applying normally-distributed randomized variability. The magnitude of this variability parameter is based on historical variation in the RTO Reliability Requirement relative to a linear trend. Table 11 shows the historical Reliability Requirement values, as well as the linear prediction and the deviation from the trend, which sets the BRA Reliability Requirement variability. The average historical deviation from the trend is 6,467 UCAP MW, or 4.1% of the average BRA Reliability Requirement.[38]

[38] The 2022/23 BRA was a notable outlier due to the exit of Dominion Energy Virginia, which extracted over 18 GW of resources and load from RPM by switching to the FRR option. Therefore, we excluded the 2022/23 when calculating historical variation in both supply and demand. FRR-based entry and exit have the effect of simultaneously decreasing (or increasing) supply and demand, and so the net effect on the remaining RPM market is mitigated as compared to a large withdrawal of supply (e.g. a large amount of retirements) which would still leave demand in RPM or vice versa. Nevertheless FRR-based exits or entry can have the effect of increasing supply-demand uncertainties as experienced in the remaining RPM market because the size of supply and demand that exit (or enter) RPM will not be exactly balanced. To ensure that our modeling accurately reflects realized supply-demand variability *including* accounting for the impact of FRR exit/entry, we have also confirmed that the Net Supply variability in our modeling is consistent with magnitudes realized in the market by applying a correlation factor between supply and demand (as discussed further in the following section).

TABLE 11: HISTORICAL VARIABILITY IN BRA RELIABILITY REQUIREMENT

Year		Historical BRA Reliability Requirement [A] *(UCAP MW)*	Linearized BRA Reliability Requirement [B] *(UCAP MW)*	Residual Above (Below) Linear Trend [C] *(UCAP MW)*
2013		149,989	156,567	(6,578)
2014		148,323	156,799	(8,475)
2015		162,777	157,030	5,747
2016		166,128	157,262	8,866
2017		165,007	157,493	7,514
2018		160,607	157,725	2,883
2019		157,092	157,956	(864)
2020		154,355	158,188	(3,833)
2021		153,161	158,420	(5,259)
Average BRA Reliability Requirement		[1]	Average [A]	157,493
Standard Deviation of Residuals		[2]	Std. Dev. [C]	6,467
BRA Reliability Requirement Variability		[3]	[2]/[1]	4.1%

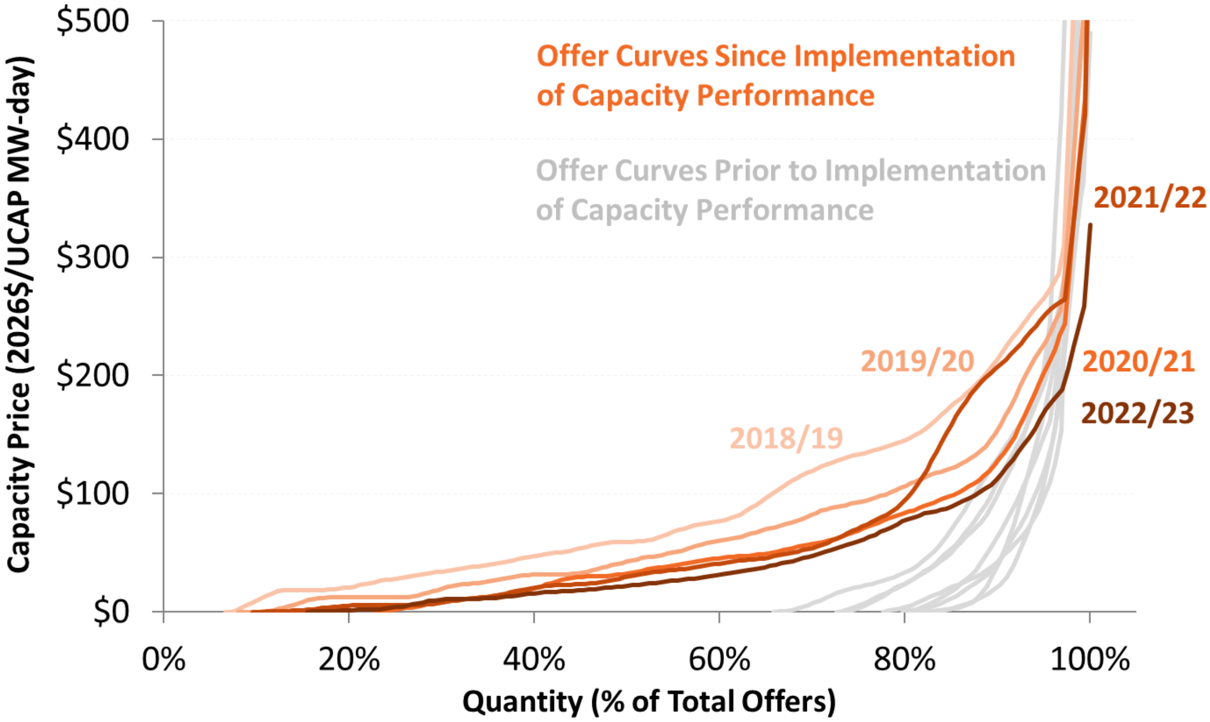
Sources/Notes: All quantities in UCAP MW; [A]: From PJM, 2013/14–2021/22 Base Residual Auction Planning Parameters; [B]: Expected value of [A] based on linear trend; [C]: [A] – [B].

C. Capacity Supply

Unlike the demand curve, the capacity market supply curve is not administratively determined and under the control of PJM. Instead, it is constructed from price-quantity pair supply offers by market participants. For our modeling, we use supply curve shapes derived from historical RPM offers from the 2009/10 to 2022/23 Planning Years. These supply curves reflect a wide range of capacity resources offered into the market and account for participant bidding behavior changes in response to rule changes and market conditions over time.

To prepare these curves for our model, we construct smoothed and normalized supply curves from the 2009/10 to 2022/23 Base Residual Auction offer data. We smooth price-quantity pairs into 1,000-MW standard blocks, adjust prices for inflation so that all prices are in 2026$, and normalize MW quantity bids so that the final supply curves quantities are represented as a percentage of BRA Total Supply for each year. Figure 16 shows these normalized curves.

FIGURE 16: NORMALIZED SUPPLY CURVES



Sources/Notes: BRA supply offer data provided by PJM.

We highlight that auctions from 2009/10 to 2017/2018 are from before PJM introduced the "Capacity Performance" measures.[39] Under Capacity Performance, resources that fail to fulfill their capacity obligation during emergency events are penalized, while resources that do fulfill their obligation are awarded bonus payments.[40] At the same time that Capacity Performance was implemented, sellers' offer caps were also increased and the resulting RPM supply curves have increased to a more elastic shape (orange lines). Upcoming changes to seller offer caps and performance regimes within the ongoing RASTF may have the potential to once again cause somewhat different characteristics in future supply curve shapes. To examine the impact of steeper and flatter supply curves on our conclusions, we have conducted additional sensitivity analysis and found relatively modest impacts as shown later in Table 17.

The total volume of supply incorporated into each draw of BRA clearing results is subject to normally-distributed random variability. Table 12 contains data from 2013/14 to 2021/22 and shows that the historical deviation of BRA Total Supply from the linear trend is 5,683 UCAP MW.

[39] PJM replaced the pre to 2018/19 capacity products with interim capacity products (with lower performance expectation than Capacity Performance resources) for the 2018/19 and 2019/20 Planning Years; 2020/21 was the first year in which exclusively Capacity Performance resources were offered in the BRA and IAs; Federal Energy Regulatory Commission, 151 FERC ¶ 61,208, Order on Proposed Tariff Revisions, Issued June 9, 2015,.

[40] PJM, PJM Manual 18: PJM Capacity Market, Section 8.4A, October 20, 2021.

This value is equivalent to 3.2% of the average BRA Total Supply from 2013/14 to 2021/22, setting the supply variability we utilize in our modeling.

TABLE 12: HISTORICAL VARIABILITY IN BRA TOTAL SUPPLY

Year	Historical BRA Total Supply [A] *(UCAP MW)*		Linearized BRA Total Supply [B] *(UCAP MW)*	Residual Above (Below) Linear Trend [C] *(UCAP MW)*
2013	160,898		165,580	(4,682)
2014	160,486		168,587	(8,101)
2015	178,588		171,594	6,994
2016	184,380		174,601	9,779
2017	178,839		177,608	1,230
2018	179,891		180,615	(724)
2019	185,540		183,623	1,917
2020	183,352		186,630	(3,278)
2021	186,502		189,637	(3,135)
Average BRA Total Supply		[1]	Average [A]	177,608
Standard Deviation of Residuals		[2]	Std. Dev. [C]	5,683
BRA Total Supply Variability		[3]	[2]/[1]	3.2%

Sources/Notes: [A]: From auction data provided by PJM; [B]: Expected value of [A] based on linear trend; [C]: [A] – [B].

In the RPM, there is a partial correlation between supply and demand. This correlation can be explained by changes in the size of PJM, as PJM's footprint has increased and demand growth proceeds, supply and demand typically both increase at comparable rates. Conversely, when a substantial volume of demand exits the market under FRR, it will exit along with a similarly-sized share of the total supply mix. Separately estimating supply and demand variability without accounting for this correlation would overstate resulting variability in net supply (i.e. offered supply minus Reliability Requirement) that produces the effect of market price volatility. We therefore apply a correlation factor between supply and demand variability parameters to ensure that net supply variability produced by our simulation model exactly matches historically observed net supply variability.

We estimate the deviation of Net Supply from a linear trend in the same manner as with the other variability calculations. The historical deviation of Net Supply from the linear trend is 2,983 UCAP MW, as shown in Table 13. This value is equivalent to 1.9% of the average BRA Reliability

Requirement from 2013/14 to 2021/22, which sets the BRA Net Supply variability size as implemented in our model.

TABLE 13: HISTORICAL VARIABILITY IN BRA NET SUPPLY

Year	Historical BRA Reliability Requirement [A] *(UCAP MW)*	Historical BRA Total Supply [B] *(UCAP MW)*	Historical BRA Net Supply [C] *(UCAP MW)*	Linearized BRA Net Supply [D] *(UCAP MW)*	Residual Above (Below) Linear Trend [E] *(UCAP MW)*
2013	149,989	160,898	10,909	9,013	1,896
2014	148,323	160,486	12,163	11,788	375
2015	162,777	178,588	15,810	14,564	1,246
2016	166,128	184,380	18,253	17,339	913
2017	165,007	178,839	13,831	20,115	(6,284)
2018	160,607	179,891	19,284	22,891	(3,607)
2019	157,092	185,540	28,447	25,666	2,781
2020	154,355	183,352	28,996	28,442	555
2021	153,161	186,502	33,341	31,217	2,124
Average BRA Reliability Requirement			[1]	Average [A]	157,493
Standard Deviation of Residuals			[2]	Std. Dev. [E]	2,983
BRA Net Supply Variability			[3]	[2]/[1]	1.9%

Sources/Notes: All quantities in UCAP MW; [A]: From PJM, 2013/14 to 2021/22 Base Residual Auction Planning Parameters; [B]: From auction data provided by PJM; [C]: [B]-[A]; [D]: Expected value of [C] based on linear trend; [E]: [C] – [D]. If we would have included the year 2022/23 that included a large exit of both supply and demand from RPM, the net supply variability would be 1.8% and would not materially impact our conclusions. In our simulation sensitivity analyses we test a large range of parameters to illustrate the implications to our estimated results if net supply variability is substantially larger or smaller than under our base assumptions.

D. Modeling the Incremental Auctions

We have updated our probabilistic simulation model in this Quadrennial Review to account for supply-demand uncertainties that unfold after the three-year BRA and before the Planning Year. The modeling accounts for load forecast uncertainty that can cause increases or decreases in the reliability requirement between the BRA and the final IA, as well as changes to supply availability that can be offered into the IAs. If the load forecast decreases, then excess supply will remain available beyond what was anticipated at the time of the BRA. If the load forecast increases, the IA will aim to procure more capacity to meet the increase in demand.

We model these forward-to-prompt adjustments as time-sequential changes between the BRA and IA within a single modeling draw:[41]

1. **Model the BRA** and determine the resulting quantity of cleared and uncleared capacity

2. **Determine IA Reliability Requirement** as of the time of the last IA, after accounting for three years of load forecast uncertainty between the BRA and the last IA. Starting with the BRA Reliability Requirement, we apply a normally distributed random variable of 1.7% to determine the IA Reliability Requirement. Under base assumptions we assume no bias to the load forecast, but we test the implications of potential load forecast bias in a sensitivity analysis.

3. **Determine IA Available Supply Offers** that can be procured. We begin with the BRA capacity that was offered but remained uncleared, under the assumption that some of these resources will remain available for purchase in the subsequent IAs (others may retire or cease development efforts and become unavailable for procurement in the IAs). We assume that 53.8% of BRA uncleared supply will remain available for procurement as of the last IA, consistent with historical market data (see Table 3).[42] We also apply a normally-distributed random variable to represent variability in the total volume of IA supply offered, the size of which is 1.0% of total BRA supply quantities, as shown in Table 15. We also assume that a minimum quantity of 1,000 MW will always be offered into the IAs.[43]

4. **Estimate Final Quantity Procured (or Released) as of the Final IA.** We utilize a simplified representation of IA auctions in our modeling, treating the auctions in a combined fashion (rather than as three separate auctions) and calculating only the final resulting quantity rather than aiming to estimate pricing outcomes in the IAs. If the Reliability Requirement increases between the BRA and the final IA, we assume that PJM will procure 100% of the

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[41] Each of the 1,000 draws from the BRA results are randomized draws that we do not attempt to capture in a time-sequential fashion; however, within each draw the BRA and IA are treated in a time-sequential fashion.

[42] This is the average Net Supply available as of the Final Incremental Auction as a percentage of BRA Uncleared Supply from the 2017/18 to 2021/22 auction cycles. We exclude 2018/19 however, due to the idiosyncratic effects of Capacity Performance transition auctions. See Table 3.

[43] See Table 3 for data on final IA total supply; 2,533 MW was offered in 2017/18 Third Incremental Auction, which was the minimum supply offered in any auction over 2012/13 and 2021/22. The volume of capacity offered in these historical auctions has been larger than the minimum 1,000 MW that we assume, because of historical supply excesses. We do not have sufficient historical data to determine the volume of capacity that might be offered in a scenario of short supply in the forward auction combined with load forecast increases. In our modeling we assume that at least 1,000 MW of incremental supply can become available in that scenario, but we acknowledge that this assumption is speculative.Table 3: Supply Offered, cleared, and Net Supply

increase, subject to limitations in IA Available Supply.[44] IA if the Reliability Requirement decreases, the model releases 50% of the reduction (in line with historically observed levels of released capacity).[45] We then estimate the final achieved level of reliability based on the final committed volume after the last IA.

Consistent with our modeling approach for the other variability calculations, we calculate historical variability in IA Reliability Requirement relative to the BRA Reliability Requirement, after removing the historical load forecast bias (see Table 14). The IA Reliability Requirement deviates from the linear trend by an average of 2,495 UCAP MW. This is equal to 1.7% of the average final IA Reliability Requirement from 2013/14 to 2021/22, and we define this percentage as the forward-to-prompt Reliability Requirement variability in our model.

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[44] We note that PJM's current approach pursues IA procurements based primarily on changes to the Reliability Requirement, rather than on the absolute need for capacity after accounting for the volumes that have already cleared in prior auctions. Our modeling aims to reflect PJM's current IA procurement practice, even though we believe that conducting IA procurements relative to residual needs would be a simpler and more straightforward approach. The current approach to determining IA procurement volumes is described in Manual 18, Section 3.5, October 20, 2021. Under current rules, if the Reliability Requirement decreases by an amount greater than the lesser of 500 UCAP MW or 1% of the prior auction's Reliability Requirement, then PJM seeks to release capacity in the IA, and vice versa if the Reliability Requirement increases.

[45] This approach aims to reflect the current market rules and historically observed levels of capacity released by PJM in the IAs. PJM currently determines the volume of capacity released based on changes in the Reliability Requirement between auctions, rather than the remaining need (or excess supply) at the time of the IAs. In each auction cycle between 2012/13 and 2021/22, the Reliability Requirement has decreased from the BRA to the Final IA. Consequently, the net effect of the IAs has been to release capacity. Therefore, we model capacity release in the IA based on historical data. The volume of capacity released in prior auctions has never been enough to fully reduce excess system capacity so that the final committed quantity is equal to the final IA Reliability Requirement. From 2013/14 to 2021/22, on average 44% of the Target Quantity (difference between BRA Reliability Requirement and IA Reliability Requirement) was released as of the Final IA. We round this to 50% for our modeling purposes. We do not have historical data to confirm how IA supply would respond if the BRA clears short. Therefore, we model IA procurement assuming PJM would acquire sufficient capacity to cover any deficit to meet the 1-in-10 LOLE target in the case of a shortfall, subject to the IA available supply.

TABLE 14: HISTORICAL VARIABILITY IN FINAL IA RELIABILITY REQUIREMENT

Year	Historical BRA Reliability Requirement [A] *(UCAP MW)*	Historical Final IA Reliability Requirement [B] *(UCAP MW)*	Delta of IA Above (Below) BRA Requirement [C] *(UCAP MW)*	Linearized Delta [D] *(UCAP MW)*	Residual Above (Below) Linear Trend [E] *(UCAP MW)*
2013	149,989	139,184	(10,805)	(10,073)	(732)
2014	148,323	141,983	(6,340)	(9,509)	3,169
2015	162,777	153,800	(8,977)	(8,945)	(32)
2016	166,128	153,158	(12,969)	(8,381)	(4,588)
2017	165,007	153,969	(11,039)	(7,818)	(3,221)
2018	160,607	152,316	(8,292)	(7,254)	(1,038)
2019	157,092	151,832	(5,260)	(6,690)	1,429
2020	154,355	148,939	(5,417)	(6,126)	709
2021	153,161	149,765	(3,396)	(5,562)	2,166
Average Final IA Reliability Requirement			[1]	Average [B]	149,438
Standard Deviation of Residuals			[2]	Std. Dev. [E]	2,495
Final IA Reliability Requirement Variability			[3]	[2]/[1]	1.7%

Sources/Notes: All quantities in UCAP MW; [A] & [B]: From auction data provided by PJM; [C]: Historical difference between Final IA Reliability Requirement [B] and BRA Reliability Requirement [A]; [D]: Expected difference between Final IA Reliability Requirement [B] and BRA Reliability Requirement [C] based on linear trend; [E]: [C] – [D].

We estimate forward-to-prompt supply variability based on historical data as shown in Table 15. Consistent with our modeling approach for other variability calculations, we calculate historical variability in final IA available supply relative to a linear trend. Final IA available supply deviates from the linear trend by an average of 1,698 MW or 1.0% of the average BRA Total Supply from 2013/14 to 2021/22, as seen in Table 15. This percentage is the forward-to-prompt supply variability assumption in our simulation modeling.

TABLE 15: HISTORICAL VARIABILITY IN IA AVAILABLE SUPPLY

Year	Historical BRA Total Supply [A] *(UCAP MW)*	Historical Final IA Total Supply [B] *(UCAP MW)*	Linearized Final IA Total Supply [C] *(UCAP MW)*	Residual Above (Below) Linear Trend [D] *(UCAP MW)*
2013	160,898	(571)	933	(1,504)
2014	160,486	1,293	2,311	(1,019)
2015	178,588	992	3,690	(2,698)
2016	184,380	3,697	5,068	(1,371)
2017	178,839	6,208	6,447	(239)
2018	179,891	10,778	7,825	2,953
2019	185,540	10,719	9,203	1,516
2020	183,352	9,651	10,582	(931)
2021	186,505	11,674	11,960	(286)
Average BRA Total Supply		[1]	Average [A]	177,609
Standard Deviation of Residuals		[2]	Std. Dev. [D]	1,698
Final IA Supply Variability		[3]	[2]/[1]	1.0%

Sources/Notes: All quantities in UCAP MW; [A] & [B]: From data provided by PJM; [C]: Expected value of [B] based on linear trend; [D]: [B] – [C].

E. Additional Sensitivity Analysis of Candidate Curve

To understand the impact of modeling assumptions on our results, we conduct various sensitivity analyses to understand how these assumptions change our estimates of VRR Curve performance. We summarize here the impact of alternative assumptions with respect to: (a) larger or smaller assumed supply and demand variability; (b) supply curve shape; and (c) the impact in the IA of load forecast bias in the three-year ahead BRA load forecast.

SENSITIVITY TO SUPPLY AND DEMAND VARIABILITY

We report here simulated performance of the Candidate Curve to alternative assumptions about the size of the variability in supply and demand. Table 16 summarizes estimated performance if variability is 33% larger and 33% smaller than base assumptions. The Candidate Curve offers comparable reliability to the Base Case when supply and demand variability is 33% smaller or larger than history. As expected, greater supply-demand variability would produce greater price volatility, lower supply-demand variability would reduce price volatility.

TABLE 16: SENSITIVITY ANALYSIS OF SUPPLY AND DEMAND VARIABILITY

	Measured After the BRA								
	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Candidate Curve									
33% Smaller Variability	$267	$68	0.6%	0.071	1,230	1.1%	7.2%	0.9%	$13,066
Base	**$267**	**$85**	**2.7%**	**0.073**	**1,221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
33% Larger Variability	$267	$99	5.6%	0.078	1,183	1.1%	14.4%	6.3%	$13,147

Sources/Notes: All prices in 2026$ and all quantities in UCAP MW; Both BRA Total Supply variability and BRA Reliability Requirement variability were modified to be 33% larger/smaller than their base values reported in Table 10.

SENSITIVITY TO SUPPLY CURVE SHAPE

As explained above, we use smoothed, inflation-adjusted, normalized supply curves from 2009/10 to 2022/23 to reflect the shape of the capacity supply curve. After introduction of Capacity Performance in 2018/19 auction cycle, capacity supply curves have been higher and relatively more elastic than previously. To test the impact of the supply curve shape on our simulated results, we evaluate how the Candidate Curve performs under the steeper curve shapes that existed prior to 2018/19, the more elastic curves observed since 2018/19, and compared these results to our base assumptions (incorporating all curves both before and after 2018/19).

We find that the shape of the supply curves does not have a substantial impact on the performance of the Candidate Curve. Table 17 shows that while the steeper pre-Capacity Performance supply curves would result in somewhat greater price volatility than the flatter Capacity Performance supply curves, estimated LOLE is virtually unchanged.

TABLE 17: SENSITIVITY ANALYSIS OF SUPPLY CURVE SHAPE

	Measured After the BRA								
	Price			Reliability					Cost
	Average ($/MW-d)	Standard Deviation ($/MW-d)	Frequency at Cap (%)	Average LOLE (events/yr)	Average Excess (Deficit) (MW)	Average Excess (Deficit) (IRM + X %)	Frequency Below Target (%)	Frequency Below IRM - 1% (%)	Average Procurement Cost ($ mln/yr)
Candidate Curve									
Pre-CP Supply Curves	$267	$91	2.8%	0.074	1,246	1.1%	12.0%	3.3%	$13,109
Base	**$267**	**$85**	**2.7%**	**0.073**	**1,221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
CP Supply Curves	$267	$67	1.4%	0.071	1,231	1.1%	8.4%	1.7%	$13,090

Sources/Notes: All prices in 2026$ and all quantities in UCAP MW; All results use Candidate Curve, with Net CONE = $267/UCAP MW-Day; Pre- Capacity Performance Supply Curves are smoothed, inflation-adjusted, normalized curves from 2009/10 to 2017/18 auctions; Capacity Performance Supply Curves are smoothed, inflation-adjusted, normalized curves from 2018/19 to 2022/23 auctions; Base run is Candidate Curve, with all supply curves from 2009/10 to 2022/23.

SENSITIVITY TO LOAD FORECAST BIAS

We analyze the performance impact of load forecast bias as a sensitivity. Despite improvements to the load forecast accuracy in recent auction years, the Reliability Requirement for the 2021/22 Third Incremental Auction was 2.2% lower compared to the Reliability Requirement from the BRA.[46] For this sensitivity, we considered the impact of a 2% and 4% over-forecast bias (when IA Reliability Requirement is smaller than the BRA Reliability Requirement), as well as a 2% under-forecast bias (when IA Reliability Requirement is greater than the BRA Reliability Requirement). Results from this sensitivity analysis are shown in Table 18. The forecast bias only affects the results of the IA, so BRA results will be equivalent for each run.

As expected, greater over-forecast bias causes greater over-procurement after the IA. Even a 2% over-forecast bias (which is close to the bias in the most recent auction cycle) has a substantial impact on over-procurement. In this scenario, the average excess grows from 1,221 UCAP MW in the BRA to 2,560 UCAP MW after the IA, an increase of 1,339 UCAP MW. In the case of the 2% under-forecast bias, the opportunity to procure additional capacity in the incremental auctions provides a modest boost in reliability to protect against capacity shortfalls. However, since we base our model on market evidence, our representation of the ability of the IA to address shortfalls is limited given the historically observed short-term supply when the RPM has been

46 For recent Capacity Performance auction cycles (2018/19 to 2021/22), the average over-forecast bias as a percent of the BRA Reliability Requirement (adjusted for FRR) is 3.6%; Data from 2018/19 to 2021/22 RPM Base Residual Auction Planning Period Parameters and 2018/19 to 2021/22 3rd Incremental Auction Planning Period Parameters.

exclusively in long market conditions. We conclude that load forecast bias does have a significant impact on curve performance, see Section II.B for additional discussion of how this issue could be addressed.

TABLE 18: SENSITIVITY ANALYSIS OF LOAD FORECAST BIAS

	Measured After the BRA				Measured After the Final Incremental Auction			
	Reliability				Reliability			
	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target
	(events/yr)	*(MW)*	*(IRM + X %)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*
Candidate Curve								
Over-forecast bias = 4%	0.073	1,221	1.1%	10.9%	0.033	3,828	3.5%	1.3%
Over-forecast bias = 2%	0.073	1,221	1.1%	10.9%	0.050	2,560	2.3%	4.0%
Base	**0.073**	**1,221**	**1.1%**	**10.9%**	**0.071**	**1,459**	**1.3%**	**11.9%**
Under-forecast bias = 2%	0.073	1,221	1.1%	10.9%	0.110	282	0.3%	34.2%

Sources/Notes: Since Base Case run assumes no load forecast bias between the BRA and the Final IA, the full Base Case results presented elsewhere (see Table 4) are the same as the Base Case run here; Therefore we do not report the full results in the table (Base Case run has Standard Deviation of Price of $85/MW-d, not shown here); All prices in 2026$ and all quantities in UCAP MW; All results use Candidate Curve, with Net CONE = $267/UCAP MW-day; Over-forecast bias indicates the BRA Reliability Requirement is greater than the Incremental Auction Reliability Requirement (and vice versa for under-forecast bias).

F. Additional Sensitivity Analysis of Alternative Curves

Table 19 provides detailed simulation results regarding the estimated performance of the alternative VRR curves developed and evaluated in Section III.E, as well as comparing these curves to the Candidate Curve and the Current VRR Curve with either a CT or CC Reference Technology.

TABLE 19: SIMULATED PERFORMANCE OF ALTERNATIVE CURVES

	Price			Reliability					Cost
	Average	Standard Deviation	Frequency at Cap	Average LOLE	Average Excess (Deficit)	Average Excess (Deficit)	Frequency Below Target	Frequency Below IRM - 1%	Average Procurement Cost
	($/MW-d)	*($/MW-d)*	*(%)*	*(events/yr)*	*(MW)*	*(IRM + X %)*	*(%)*	*(%)*	*($ mln/yr)*
Candidate Curve									
True Net CONE = 0.6 x CC	$160	$57	0.0%	0.043	2,861	2.5%	0.0%	0.0%	$7,939
True Net CONE = CC	**$267**	**$85**	**2.7%**	**0.073**	**1,221**	**1.1%**	**10.9%**	**3.3%**	**$13,104**
True Net CONE = CT	$326	$94	9.8%	0.098	388	0.4%	31.0%	11.5%	$15,889
True Net CONE = 1.4 x CC	$374	$94	21.2%	0.128	-393	-0.3%	50.0%	24.8%	$18,092
Current Curve, CT									
True Net CONE = 0.6 x CC	$160	$52	0.0%	0.026	4,548	4.0%	0.0%	0.0%	$8,029
True Net CONE = CC	**$267**	**$74**	**1.5%**	**0.059**	**2,026**	**1.8%**	**7.5%**	**2.0%**	**$13,169**
True Net CONE = CT	$326	$86	7.8%	0.085	922	0.8%	23.2%	9.0%	$15,941
True Net CONE = 1.4 x CC	$374	$87	17.9%	0.117	-25	0.0%	43.2%	20.0%	$18,133
Current Curve, CC									
True Net CONE = 0.6 x CC	$160	$52	0.0%	0.034	3,716	3.2%	0.0%	0.0%	$7,978
True Net CONE = CC	**$267**	**$81**	**2.1%**	**0.069**	**1,431**	**1.3%**	**10.0%**	**2.9%**	**$13,119**
True Net CONE = CT	$326	$92	9.3%	0.095	510	0.5%	28.8%	10.8%	$15,900
True Net CONE = 1.4 x CC	$374	$92	19.6%	0.126	-318	-0.2%	48.4%	24.4%	$18,100
Alternative 1									
True Net CONE = 0.6 x CC	$160	$65	0.0%	0.054	2,032	1.8%	0.0%	0.0%	$7,909
True Net CONE = CC	**$267**	**$99**	**5.7%**	**0.071**	**1,280**	**1.1%**	**5.7%**	**2.6%**	**$13,132**
True Net CONE = CT	$326	$107	15.1%	0.087	732	0.7%	15.1%	8.2%	$15,949
True Net CONE = 1.4 x CC	$374	$105	29.3%	0.108	141	0.2%	29.3%	16.9%	$18,182
Alternative 2									
True Net CONE = 0.6 x CC	$160	$57	0.0%	0.040	3,077	2.7%	0.0%	0.0%	$7,953
True Net CONE = CC	**$267**	**$92**	**5.2%**	**0.066**	**1,566**	**1.4%**	**5.2%**	**2.1%**	**$13,146**
True Net CONE = CT	$326	$103	14.3%	0.084	867	0.8%	14.3%	7.6%	$15,958
True Net CONE = 1.4 x CC	$374	$103	28.8%	0.107	208	0.2%	28.8%	16.4%	$18,187
Alternative 3									
True Net CONE = 0.6 x CC	$160	$56	0.0%	0.061	1,789	1.6%	2.3%	0.0%	$7,873
True Net CONE = CC	**$267**	**$91**	**5.1%**	**0.098**	**220**	**0.2%**	**38.2%**	**6.5%**	**$13,012**
True Net CONE = CT	$326	$103	14.3%	0.124	-471	-0.4%	63.5%	16.7%	$15,796
True Net CONE = 1.4 x CC	$374	$103	28.9%	0.156	-1,126	-0.9%	79.5%	33.8%	$18,003
Alternative 4									
True Net CONE = 0.6 x CC	$160	$54	0.0%	0.051	2,397	2.1%	1.7%	0.0%	$7,907
True Net CONE = CC	**$267**	**$86**	**4.8%**	**0.093**	**440**	**0.4%**	**36.3%**	**6.0%**	**$13,025**
True Net CONE = CT	$326	$100	13.8%	0.121	-365	-0.3%	62.5%	15.9%	$15,803
True Net CONE = 1.4 x CC	$374	$101	28.4%	0.154	-1,068	-0.9%	79.2%	33.5%	$18,008

Sources/Notes: All prices in 2026$ and all quantities in UCAP MW; For Current Curve, CT, Administrative Net CONE = $326/UCAP MW-Day and price cap is Max(**1.5 × CT Net CONE**, CT CONE), for all other curves Administrative Net CONE = $267/UCAP MW-Day and price cap is Max(1.75 × CC Net CONE, **CC CONE**); **bolded text** indicates which parameter sets the price cap for each curve; All CONE values from 2022 Net CONE Study.

AUTHORS

Dr. Kathleen Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on: energy, capacity, and ancillary service market design; the design of carbon and environmental policies; valuation of traditional and emerging technology assets; and strategic planning in the face of industry disruption. Dr. Spees has supported PJM in a number of market design efforts and modeling analyses.

Dr. Samuel Newell is an economist and engineer with over 20 years of experience consulting to the electricity industry. His expertise is in the design and analysis of wholesale electricity markets and in the evaluation of energy/environmental policies and investments, including in systems with large amounts of variable energy resources. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning.

Dr. Andrew Thompson is an Electricity Modelling Specialist with expertise in electricity market design, regulatory economics, and policy analysis of network industries, particularly in the energy sector. He has assisted clients on several aspects of wholesale electricity market reform including energy, capacity, ancillary services, and demand response design, capacity auction enhancements and analysis, cost of capital estimations for electric and gas utilities, and generation asset valuation and economic damages estimations.

Xander Bartone is a Research Analyst with expertise in electricity market design and policy analysis. He earned his BA in International Relations and Mathematics from Pomona College.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Kathleen Spees**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Kathleen Spees and Samuel A. Newell on Behalf of PJM Interconnection, L.L.C. Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," are true and correct to the best of my knowledge, information, and belief.

Kathleen Spees

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Samuel A. Newell**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Kathleen Spees and Samuel A. Newell on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

____

Samuel A. Newell

Attachment D

Affidavit of
Samuel A. Newell, John M. Hagerty,
and Sang H. Gang

UNITED STATES OF AMERICA
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.

1. Our names are Dr. Samuel A. Newell, John M. Hagerty, and Sang H. Gang. Dr. Newell is employed by The Brattle Group ("Brattle") as a Principal and Mr. Hagerty as a Senior Associate. Mr. Gang is employed by Sargent & Lundy ("S&L") as a Principal Consultant. We are submitting this affidavit in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to adjust the administrative Cost of New Entry ("CONE") parameter, representing the cost of building a generation plant for use in PJM's capacity market (known as the Reliability Pricing Model or "RPM").

2. Dr. Newell and Mr. Hagerty have extensive experience estimating CONE in capacity markets administered by regional transmission organizations ("RTOs"). Dr. Newell co-authored the prior three PJM CONE studies and submitted affidavits in ensuing litigation, which informed the Net CONE values PJM used in its annual capacity auctions for the last ten years. In addition, Dr. Newell's extensive related experience in market design for resource adequacy for ISO-New England, PJM, New York Independent System Operator, Inc., Midcontinent Independent System Operator, Inc., and Electric Reliability Council of Texas, has provided broad perspective on the capacity market context in which CONE is used. Dr. Newell also has led numerous generation asset valuation studies and resource planning studies. Mr. Hagerty co-authored the 2014 and 2018 PJM CONE study as well as similar studies for ISO-NE and the Alberta Electric System Operator.

3. Dr. Newell is an economist and engineer with 24 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. Prior to joining Brattle, he was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at Kearney. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

4. Mr. Hagerty is an electricity market analyst and engineer with 10 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. He earned a M.S. in Technology and Policy from the Massachusetts Institute of Technology and a B.S. in Chemical Engineering from the University of Notre Dame.

5. Mr. Gang has extensive experience assessing power plant technologies and estimating plant capital costs, operation and maintenance ("O&M") costs, and performance characteristics. In the last six years, Mr. Gang has been leading S&L's electric power resource planning

projects including evaluation of various generation and interconnection options. Mr. Gang also led the S&L team in working with Brattle in estimating the CONE for new merchant generation resources for the new centralized capacity market in Alberta, Canada.

6. Mr. Gang is an engineer with 14 years of experience in engineering design and consulting of a wide range of electric power projects including nuclear, gas, coal, biomass, wind, solar PV, and battery energy storage technologies. He is a licensed Professional Engineer in the State of Illinois and earned a B.S. in Electrical Engineering from the University of Illinois at Urbana-Champaign.

7. Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes included as Exhibit No. 1 to our affidavit.

8. In July, 2021, PJM retained Brattle to help review, as required periodically under PJM's tariff, the Variable Resource Requirement ("VRR") Curve used as the demand curve in RPM auctions, including key components of that curve, *i.e.*, the CONE and the method to estimate the net revenues the CONE plant would earn in the PJM Region's energy and ancillary services markets ("EAS Offset"). Dr. Newell led the Brattle review of CONE parameters, together with Mr. Gang and his team at S&L as a sub-contractor. The Brattle team's role was to estimate CONE, starting by determining the configurations and locations of the reference plants, overseeing S&L's estimates of the plant proper costs and fixed O&M costs, estimating certain components of capital costs (*e.g.*, gas and electric interconnection and land costs), estimating certain components of fixed O&M costs (*e.g.*, property taxes and firm gas contracts), analyzing the key financial assumptions (*e.g.*, cost of capital), and calculating the levelized costs. S&L's role was to contribute expertise in determining the configurations and locations of the reference plants, and to provide detailed capital and fixed O&M cost estimates and performance characteristics of the reference plants specified for each PJM CONE Area.

9. The analysis involved extensive input and feedback from stakeholders, throughout the process, through several half-day workshops. The first workshop outlined the planned approach. The second presented the initial selection of reference technology. The third presented preliminary results, and the fourth presented final results. At the workshops and in writing, stakeholders had a chance to ask questions, provide comments, and offer their own presentations. We responded to questions at the workshops and in writing. Throughout the process, we discussed the assumptions and results with PJM staff and with PJM's Independent Market Monitor.

10. The results of the analysis completed by Brattle and S&L are set forth in a report entitled "PJM CONE 2026/2027 Report" ("2022 CONE Study"). A copy of the 2022 CONE Study, which was prepared under our direction and supervision, is included as Exhibit No. 2 to our affidavit.

11. This affidavit attaches our 2022 CONE Study and summarizes the methodology and results regarding the selection of reference technology, the bottom-up cost analysis, and the calculation of CONE. Separate affidavits address the cost of capital and the EAS Offset methodology.

12. The selection of reference technology considered three criteria that were reviewed with stakeholders: (1) feasibility to build within the three-year period between the Base Residual Auction and the delivery year; (2) economic viability, as indicated by actual merchant entry and competitive net costs; and (3) amenability to accurate estimation of its Net CONE. We applied those criteria to a broad range of technologies, which resulted in selecting a natural gas-fired combined cycle (CC). The CC is feasible to build, and we did not find any clear indication it cannot be built even in areas with more stringent environment regulations. It is the technology with the largest amount of recent merchant entry in PJM and a lower estimated Net CONE than the other candidate resources. It also has relatively low estimation error due to its commercial standardization and the availability of forward prices for on-peak power for estimating its EAS Offset (if using a forward EAS Offset). By comparison, combustion turbines ("CTs") continue to be less economic than CCs and have demonstrated extremely limited entry in PJM. Battery energy storage systems ("BESS") had much higher Net CONE when calculated in early 2022. We have not evaluated how the BESS Net CONE would change with the recent passage of the Inflation Reduction Act of 2022. Several other technologies were screened out earlier for having higher Net CONE, dependence on renewable energy certificates, and/or higher estimation error (wind and solar) or estimation error and non-scalability of costs (energy efficiency and demand response).

13. We provided detailed CONE estimates for BESS and CTs as well as CCs in the 2022 CONE Study, but from here forward focus on the CC as the recommended Reference Resource for the VRR Curve.

14. Our starting point for estimating CONE was to determine technical specifications and representative locations for plants. To do so, we relied primarily on the "revealed preference" of developers in the PJM region and around the U.S., as reflected by recent and proposed gas-fired plants. For CONE Areas where revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices.

15. For the reasons provided in the 2022 CONE Study, we determined the representative CC plant should be 1,182 MW (on average for the four CONE areas) with two trains each with a single gas turbine, a heat recovery steam generator, and steam turbine (*i.e.*, two "single-shaft 1×1s") with duct-firing capacity. We further determined, based on predominant practice and stakeholder input, that the representative CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability. The CC has a higher-heating value average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions.

16. Based on this configuration, we estimated capital and fixed O&M costs for each CONE Area, as described in the 2022 CONE Study. For each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction ("EPC") costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimated annual fixed O&M costs, including labor, materials, property taxes, and insurance. To properly capture the effects of the current high-inflation environment, all cost estimates are based on

actual costs of inputs as of January 2022, then escalated costs for a plant with a 2026/27 delivery year using the most recent inflation rate forecasts using Blue Chip Economic Indicators, plus a 1.6% real escalation rate for labor, as provided by S&L. The inflation forecast is 3.9% on average from January 2022 to the middle of the plant construction period in November 2024, and 2.2% thereafter.[1]

17. For the costs of firm gas transportation, we applied the tariff rates on an annual basis for representative existing pipelines in each CONE Area. Some stakeholders questioned whether that could understate the cost of obtaining firm transportation service where capacity is constrained and expansion is needed to accommodate new generation. While we acknowledged the possibility that firm gas would cost more in some circumstances (although it would be difficult to identify and quantify generically by zone), other factors could work in the other direction. In particular, a generator with firm transportation can monetize extra value during constrained periods when the local spot price of gas can exceed the cost of commodity plus transportation under the tariff rate. The generator can realize such value by generating and earning high energy margins when economic; or when uneconomic and not in electricity shortage conditions, by releasing pipeline capacity or remarketing the gas locally. Other possible ways to avoid high costs of incremental firm capacity include permitting oil backup in some circumstances, or simply bearing exposure to capacity performance penalties. In light of such countervailing possibilities, the assumed tariff rates provide a reasonable balance. Indeed, a gas marketer we interviewed agreed that the existing tariff rates provided a good estimate of the firm transport costs that a new CC would face. This is one of many such reasonable judgments necessary for estimating CONE.

18. We then calculated a levelized CONE value for the CC plant in each CONE Area employing a reasonable discount rate of 8.85% based on the estimated after-tax weighted average cost of capital ("ATWACC") value, as further explained in the affidavit of Dr. Zhou and Mr. Pfeifenberger. We calculated levelized costs assuming 20 years of cash flows that are constant in nominal terms (*i.e.*, declining in real terms). This assumed revenue trajectory reasonably reflects the expectations of developers in an environment with continued technological progress that may lower the cost per kW of newer competing plants, and with long-term threats from environmental policies and from competing technologies.

19. The resulting estimated CONE for the reference CC plant in each CONE Area with an online date of June 1, 2026 is shown in Table 1. The values shown here exceed those presented in the 2022 CONE Study by about 8.2% because of two updates that were necessary given recent changes in economic conditions: first, the estimated ATWACC has increased from 8% in our 2022 CONE Study to 8.85% today, as explained in the concurrently-filed ATWACC affidavit by Dr. Bin Zhou and Mr. Johannes Pfeifenberger. Second, inflation has increased beyond that assumed in the 2022 CONE Study, particularly

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1 See "Blue Chip Economic Indicators – Top Analysts' Forecasts of the US Economic Outlook for the Year Ahead," Vol. 47, No. 9. Wolters Kluwer, September 12th, 2022, p.5 for the latest short-term forecast through 2023. For the latest long-term forecast beyond 2023, see "Blue Chip Economic Indicators – Top Analysts' Forecasts of the US Economic Outlook for the Year Ahead," Vol. 47, No. 6. Wolters Kluwer, June 10th, 2022, p.15.

between January 2022 and the middle of the construction period, where the prior rate had been 2.9% instead of the updated 3.9% as noted above.

Table 1. CC Plant CONE Estimates

	CONE Area	CC CONE *(2026$/ICAP MW-Year)*	CC CONE *(2026$/ICAP MW-Day)*
1	EMAAC	$198,200	$543
2	SWMAAC	$193,100	$529
3	Rest of RTO	$197,800	$542
4	WMAAC	$199,700	$547

20. The two most important observations about these CONE estimates affecting their use in the VRR Curve is that they are higher than prior CC CONE estimates and more uncertain than in the past. Averaged across the four CONE Areas, the 2026/27 CC CONE is $540/MW-Day (ICAP) in 2026 dollars. This is nominally $220/MW-day (ICAP) higher than PJM's 2022/23 CC CONE of $320/MW-Day (ICAP) based on the 2018 CONE Study.[2] Four factors explain this increase: (1) bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $30/MW-Day (ICAP) to CONE; (2) ATWACC increased from 8.2% in the 2022/23 CC CONE calculation to 8.85% today, adding another $15/MW-Day (ICAP); (3) the projected costs of materials, equipment, and labor for a 2026 online date have escalated substantially, largely due to recent inflation (which has been substantially higher than projected in the 2018 study for a 2022 online date) and additional cost escalation projected through 2026, adding $104/MW-Day (ICAP) to the nominal cost; and (4) the updated CC plant configuration includes costlier dry-cooling and a gas-only design with firm gas transportation contracts due to more constrained environmental permitting regimes (along with smaller increases from changing from one 2×1 CC to two double-train 1×1 CCs), adding $71/MW-Day (ICAP).[3]

21. Yet indicative CC Net CONE remains significantly below the indicative CT Net CONE ("indicative" because actual Net CONE will be determined by PJM when it updates the EAS Offset shortly before each Base Residual Auction). Updating the CONE values to $558/MW-Day (converted to UCAP terms by dividing the $540 by (1-3.1%EFORd)) but maintaining the $209/MW-Day (UCAP) EAS Offset estimates from the 2022 CONE Study,

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[2] See 2022/23 base value referenced in the February 3, 2022 revision of PJM's "2023-2024 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy;" https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-default-new-entry-mopr-offer-prices.ashx. We reproduced this value by changing the ATWACC in our 2022 CONE Study model to PJM's 8.2% filed value.

[3] These contributions to the total difference were derived by starting with the 2022/23 value and applying changes incrementally, in the sequence presented in this paragraph. A different sequence would indicate different contributions, due to interactions among the factors. For example, if the changes in plant configuration were applied first, their contribution would appear smaller, and if bonus depreciation and ATWACC were changed last, their contributions would appear substantially larger.

the indicative CC Net CONE for the RTO becomes \$349/MW-day (UCAP), which is \$39/MW-day lower than for the CT, all in 2026 dollars. This advantage supports our recommendation that the CC should be used as the Reference Resource. The CC's economic advantage would be even higher now that forward prices have increased substantially relative to June 2021, the date of forward curves used in the 2022 CONE Study.

22. In May 2022, PJM updated its estimate of forward-looking CC EAS Offsets using forward curves from April 2022 and found that EAS Offsets had increased by \$84/MW-Day (UCAP) for the RTO in 2026 dollars.[4] This reduces indicative CC Net CONE from \$349/MW-Day (UCAP), noted above, to \$264/MW-Day (UCAP). Thus the adoption of the CC as the Reference Resource and the higher EAS revenue offset results in a 2026/27 indicative Net CONE that is nominally lower than the \$276/MW-Day (UCAP) CT Net CONE used in the most recent BRA for the 2023/24 commitment period.

23. These estimates are uncertain, particularly in the current context of the industry's rapid transition to lower-emitting resources and volatility in fuel markets and the economy generally.[5] That uncertainty makes it more difficult to know investors' long-term revenue recovery expectations affecting CONE. Our 2022 CONE Study shed some light on the degree of uncertainty through sensitivity analyses with different assumptions on a CC's economic lifetime, and on different possible plant configurations. With our updated financial assumptions and substantially higher indicative EAS Offset, the range we reported becomes even larger as a percentage of a (reduced) indicative Net CONE, now −30% to +21%. The full uncertainty range should be even wider considering EAS uncertainties and other variables beyond those we analyzed. These uncertainties have implications for the VRR curve design, as discussed in our concurrent VRR Curve affidavit.

24. This concludes our affidavit.

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4 See Natalie Tacka, *Forward Net Energy & Ancillary Services Revenue Offset Methods & Comparisons*, PJM Interconnection, L.L.C. (May 20, 2022), https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220520-special-session/item-03---forward-net-energy--ancillary-services-revenue-offset-methods--comparisons---post-meeting.ashx, showing \$286/MW-Day for the RTO. We have confirmed with PJM that the units are in 2026 dollars per MW-Day in ICAP terms, and that the \$286/MW-Day included \$9.18/MW-Day of Net Reactive Service Revenue. Since then, PJM has decided to assume Net Reactive Service Revenues of only \$6.98/MW-Day, so the most updated EAS Offset becomes \$284/MW-Day (ICAP) in 2026 dollars. We translate this to \$293/MW-Day (UCAP), by dividing by (1 − 3.1% EFORd), with EFORd taken from PJM's May presentation. Compared to the \$209/MW-Day (UCAP) EAS Offset presented in Table 20 of the 2022 CONE Study, the updated \$293/MW-Day EAS Offset is \$84/MW-Day (UCAP) higher.

5 Factors contributing to Net CONE uncertainty include technological change; uncertainties in expected gas market prices (and consequently, in electricity prices and EAS Offsets); recent uncertainties and instabilities in commodity markets, labor markets, supply chains, and financial markets across many sectors that have introduced challenges in estimating an accurate CONE; and the effects of state and federal policies and fleet turnover.

Exhibit No. 1

Samuel A. Newell,
John M. Hagerty,
and Sang H. Gang
Qualifications

Samuel Newell

PRINCIPAL

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Dr. Newell leads Brattle's Electricity Group of over 50 consultants addressing the most challenging economic questions facing an industry transforming to clean energy.

His expertise centers on electricity wholesale markets, market design, generation asset valuation, integrated resource planning, and transmission planning. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Electricity Litigation & Regulatory Disputes

EDUCATION

- **Massachusetts Institute of Technology**
  PhD in Technology Management and Policy
- **Stanford University**
  MS in Materials Science and Engineering
- **Harvard University**
  AB in Chemistry and Physics

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2004–Present)**
  Principal
- **Cambridge Energy Research Associates (2003–2004)**
  Director
- **Kearney (1998–2002)**
  Manager

CAPACITY MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **PJM's Capacity Market Reviews and Parameters**. For PJM, conducted all five official reviews of its Reliability Pricing Model (2008, 2011, 2014, 2018, and 2022). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE) parameter, and the methodology for estimating net energy and ancillary services revenues. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. Relatedly, have also provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources, for use in the Minimum Offer Price Rule. Submitted testimonies before FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at FERC.
- **Buyer Market Power Mitigation in PJM**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Resource Accreditation**. Co-authored two whitepapers in 2022 for the Massachusetts Attorney General's Office on resource accreditation methodologies, including "ELCC" and empirical methods; evaluated reform options for New England.
- **ISO-NE Capacity Demand Curve Design.** For ISO New England (ISO-NE), developed a demand curve for its Forward Capacity Market. Solicited staff and stakeholder input, then established market design objectives. Provided a range of candidate curves and evaluated them against objectives, showing tradeoffs between reliability uncertainty and price volatility (using a probabilistic locational capacity market simulation model we developed). Worked with Sargent & Lundy to estimate the Net Cost of New Entry to which the demand curve prices are indexed. Submitted testimonies before FERC, which accepted the proposed curve.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO-NE, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity Market. Worked with Sargent & Lundy to conduct bottom-up analyses of the costs of constructing and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable, given

their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, reducing installed capacity requirements) for capacity costs and prices, emergency procurement costs, and energy prices. Whitepaper submitted by ISO-NE to the FERC.
- **New York State Resource Adequacy Constructs**. For NYSERDA, evaluated the customer cost impacts of several alternative constructs that differ in whether FERC or the state sets the rules and how buyer-side mitigation is implemented.
- **Evaluation of Moving to a Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a 4-year forward capacity market. Evaluated options based on stakeholder interviews and the experience of PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs. Recommendations were used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- **MISO Resource Adequacy Framework for a Transforming Fleet**. Currently advising MISO in its Resource Availability and Need initiative (2020-present) to reform its resource adequacy framework to address year-round shortage risks as the fleet transforms. Presenting to stakeholders on resource accreditation, determination of LSE requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before FERC.
- **MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.

- **Singapore Capacity Market Development**. For the Energy Market Authority (EMA) in Singapore, developed a complete forward capacity market design in 2018-2021. Worked with EMA in collaboration with other government entities and stakeholders. Published high-level design documents and presented to stakeholders. Currently assisting with detailed design and implementation.
- **Western Australia Capacity Market Design**. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design and implementation of a new forward capacity market. Reviewed the high-level forward capacity market design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; helped define administrative processes needed to conduct the auction and the governance of such processes.
- **Western Australia Reserve Capacity Mechanism**. For EnerNOC, evaluated Western Australia's administrative Reserve Capacity Mechanism in comparison with international capacity markets, and made recommendations for improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other senior government officials.

ENERGY & ANCILLARY SERVICES (AND OTHER) MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **ERCOT Post-Uri Market Reform**. Advised ERCOT and the Public Utility Commission of Texas regarding market design for reliability. Interviewed Commissioners, ERCOT, and stakeholders. Helped frame the problem as primarily resource adequacy and secondarily as operational reliability; evaluated market design proposals to support resource adequacy; evaluated refinements to the Operating Reserve Demand Curve and to Ancillary Services markets; presented recommendations and commented on stakeholder proposals at numerous PUCT workshops. Later invited by the State Energy Plan Advisory Committee to testify.
- **ERCOT's Proposed Future Ancillary Services Design**. For the Electric Reliability Council of Texas (ERCOT), evaluated the benefits of its proposal to unbundle ancillary services, enable broader participation by load resources and new technologies, and tune its procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load resources, and new technologies could participate. Directed their simulation of the market using PLEXOS, and evaluated other benefits outside of the model.
- **Investment Incentives in ERCOT**. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy; and (3) evaluate options to enhance resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability.

Conclusions informed a PUCT proceeding in which I filed comments and presented at several workshops.

- **Operating Reserve Demand Curve (ORDC) in ERCOT**. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted backcast analyses using interval-level data provided by ERCOT and assuming generators rationally modify their commitment and dispatch in response to higher prices under the ORDC. Analysis was used by ERCOT and the PUCT to inform selection of final ORDC parameters.
- **Economically Optimal Reserve Margins in ERCOT**. For ERCOT, co-led studies (2014 and 2018) estimating the economically-optimal reserve margin, and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load-shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- **Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals.** Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **IESO's Market Renewal Program / Energy Market Settlements**. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for the new day-ahead and real-time nodal market, including make-whole payments for natural gas-fired combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- **Forward Energy and Ancillary Services (EA&S) Revenues in PJM**. For PJM, developed a method for using forward prices to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters. Collaborated with Sargent &

Lundy to establish resource characteristics, and with PJM staff to conduct hourly virtual dispatch. Filed successful testimony with FERC.

- **Energy Price Formation in PJM**. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with FERC, and which FERC largely accepted and cited in its April 2019 Order.
- **Energy Market Monitoring & Market Power Mitigation**. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- **Market Design for Energy Security in ISO-NE**. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to the NEPOOL Markets Committee.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **Market Development Vision for MISO**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2–5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **RTO Accommodation of Retail Access**. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.
- **LMP Impacts on Contracts**. For a California state agency, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Estimated congestion costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using a third party's GE-MAPS market simulations (and helped

to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- **Australian Electricity Market Operator (AEMO) Redesign**. Advised AEMO on market design reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives; interviewed stakeholders; assessed local market characteristics affecting the design; synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The Public Utilities Office posted our whitepaper in support of its conclusions.

TRANSMISSION PLANNING AND MODELING

- **Initial Report on the New York Power Grid Study**. With NYSERDA, NYDPS, and Pterra, submitted a report to the NYPSC projecting New York's transmission needs to support its long-term clean energy goals under the Climate Leadership and Community Protection Act. Our work synthesized findings from three sub-reports addressing local T&D needs, offshore wind, and overall bulk system needs.
- **Value of a NY Public Policy Transmission Project**. On behalf of NY Transco LLC, submitted testimony in 2020 regarding the economic benefits of Transco's proposed "Segment B" transmission project. Critiqued an opposing expert's production cost analysis and broader benefit-cost analysis.
- **Benefit-Cost Analysis of New York AC Transmission Upgrades**. For the New York Department of Public Service (DPS) and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability between Upstate and Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift the location of future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. DPS used our analysis to inform its recommendation to the NY Public Service Commission to declare a "Public Policy Need" to build a project such as the best ones identified.
- **Evaluation of New York Transmission Projects**. For the New York Department of Public Service (DPS), provided a cost-benefit analysis for the "TOTS" transmission projects.

Showed net production cost and capacity resource cost savings exceeding the project costs, and the lines were approved. The work involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.

- **Economic and Environmental Evaluation of New Transmission to Quebec**. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- **Benefit-Cost Analysis of a Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the energy market impacts using the PROMOD model.
- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.
- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.
- **Analysis of Transmission Constraints and Solutions**. Performed a multi-client study identifying major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions. Worked with transmission engineers from client organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several economic major transmission projects.
- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle evaluation of commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and other models. Intensively tested each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability to calibrate models with backcasts using actual RTO data.

ENERGY POLICY ANALYSIS

- **Life Extension for Diablo Canyon**. For an environmental organization in CA in 2022, evaluated the net benefits of extending the operating life of the Diablo Canyon Nuclear Power Plant. Calibrated the base case in Brattle's gridSIM capacity expansion model to existing studies sponsored by CA state agencies, and estimated the impacts of retaining Diablo Canyon in terms of emissions, fixed and variable costs, and ability to meet both reliability objectives and clean energy goals.
- **Tariffs on PVs**. For a renewable energy advocacy group in 2022, evaluated the impacts of potential anti-circumvention tariffs that the Department of Commerce was considering imposing on PVs from four countries. Our team developed a trade model to estimate the impact on market prices for panels in the US; then leveraged our gridSIM capacity expansion model to estimate the impact on utility-scale investments, emissions, and energy prices/costs; then incorporated into a macroeconomic model to estimate effects on jobs and GDP.

- **Renewable Energy Tax Policy Impacts**. For ACORE, a renewable energy advocacy group, evaluated alternative proposals to extend and expand tax credits in 2021. Simulated investment, costs, prices and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model. Informed client's policy position.
- **Clean Energy Transformation**. For NYISO, led a team to project how the fleet may evolve to meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used gridSIM to model investment and operations subject to constraints on reliability and clean energy. Evaluated technology needs for meeting load during extended periods of low wind/solar. Study results helped inform questions about future market design and reliability.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad group of stakeholders opposing the rule in a filing before FERC, evaluated DOE's proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply; the likely cost of the rule; and the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.

GENERATION AND STORAGE ASSET VALUATION, AND PROCUREMENTS

- **Value of Flexibility in ERCOT**. For a large company evaluating a range of investment strategies, assessed the value of flexibility in ERCOT today and in the future as wind and solar penetration increases. Used Brattle's GridSIM model to project investments and retirements over the next 10 years. Analyzed the likely increase in demand for ancillary services. Simulated system operations accounting for short-term uncertainty in net load forecasts, using ENELYTIX PSO to model day-ahead and real-time operations.
- **Storage Development Company Due Diligence**. For an international investor consider an equity investment in a storage development company in ERCOT, reviewed the developer's business model, interviewed the developer, and compared their revenue projections to our own.
- **Storage Asset Development in New York**. For a renewable generation company considering developing large new storage assets in New York City and Long Island, provided a market analysis, including a 20-year estimate of net revenues. Used Brattle's GridSIM model to simulate investment, operations, prices, and revenues over that timeframe, after calibrating the model to current actual prices.
- **Valuation of a Gas-Fired Combined-Cycle Plant in ERCOT**. For a generation company, estimated net revenues for an existing plant, using Brattle's GridSIM model to project investment/retirement, operations, prices, and revenues over that timeperiod, after calibrating the model to recent prices. Assessed market risks.
- **Evaluation of Hydropower Procurement Options**. For a potential buyer of new transmission and hydropower from Quebec, evaluated costs and emissions benefits

under a range of contracting approaches. Accounted for the possibility of resource shuffling and backfill of emissions. Considered the value of storage services.

- **Valuation of a Gas-Fired Combined-Cycle Plant in New England**. For a party to litigation, submitted testimony on the fair market value of the plant. Simulated energy and capacity markets to forecast net revenues, and estimated exposure to capacity performance penalties. Compared the valuation to the transaction prices of similar plants and analyzed the differences. Collaborated with a co-testifying export on project finance to assess whether the estimated value would suffice to cover the plant's debt and certain other obligations.
- **Valuation of a Portfolio of Combined-Cycle Plants across the U.S.** For a debt holder in a portfolio of plants, estimated the fair market value of each plant in 2018 and the plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our own models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuation analyses across a range of scenarios. Provided insights into market and regulatory drivers and how they may evolve.
- **Wholesale Market Value of Storage in PJM**. For a potential investor in battery storage, estimated the energy, ancillary services, and capacity market revenues their technology could earn in PJM. Reviewed PJM's market participation rules for storage. Forecast capacity market revenues and the risk of performance penalties. Developed a real-time energy and ancillary service bidding algorithm that the asset owner could employ to nearly optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- **Valuation of a Generation Portfolio in ERCOT**. For the owners of a portfolios of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over a range of plausible scenarios. Analyzed the effects load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how future changes in these drivers could cause the value to shift over time.
- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially

on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.

- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a revenue forecast for energy and capacity. Evaluated the implications of several scenarios around key uncertainties.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net

energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

INTEGRATED RESOURCE PLANNING (IRP)

- **Resource Planning in Hawaii**. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- **IRP in Connecticut (for 2008, 2009, 2010, 2012, and 2014 Plans)**. For two major utilities and the state Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive IRPs. Plans involved projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, REC markets, and suppliers' likely investment/retirement decisions. Addressed electricity supply risks, natural gas supply into New England, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.
- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and

facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

DEMAND RESPONSE (DR) MARKET PARTICIPATION, MARKET POTENTIAL, AND MARKET IMPACT

- **Demand Response (DR) Integration in MISO**. Through a series of assignments, helped MISO incorporate DR into its energy market and resource adequacy construct, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers; (2) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets. Identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; (3) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying the practices of other RTOs and by characterizing the DR resources within the MISO footprint.
- **Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity.** For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Compensation Options for DR in ISO-NE's Energy Market**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **ERCOT DR Potential Study**. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the potential for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- **Wholesale Market Impacts of Price-Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic

retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.

- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Value of DR Investments**. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

GAS-ELECTRIC COORDINATION

- **Gas Pipeline Investment for Electricity.** For the Maine Office of Public Advocate, co-sponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other experts' reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- **Gas Pipeline Investment for Electricity.** For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- **Fuel Adequacy and Other Winter Reliability Challenges**. For an ISO, co-authored a report assessing the risks of winter reliability events due to inadequate fuel, inadequate weatherization, and other factors affecting resource availability in the winter. Evaluated solutions being pursued by other ISOs. Proposed changes to resource adequacy requirements and energy market design to mitigate the risks.
- **Gas-Electric Reliability Challenges in the Midcontinent**. For MISO, provided a PowerPoint report assessing future gas-electric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.

RTO PARTICIPATION AND CONFIGURATION

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on (1) MISO and PJM's real-time inter-RTO coordination process, and (2) the economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO's and PJM's energy prices and shadow prices on reciprocal coordinated flow gates.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

ENERGY LITIGATION

- **Enforcement Matter in ISO-NE's Day-Ahead Load Response Program**. Provided expert testimony on behalf of the FERC Office of Enforcement in "Fed. Energy Regulatory Comm'n v. Silkman" in the U.S. District Court of Maine regarding allegations that defendant "engag[ed] in a fraudulent scheme to manipulate the ISO New England, Inc. (ISO-NE) Day-Ahead Load Response Program" by gaming the baseline and claiming false reductions in load. Submitted initial and rebuttal reports analyzing whether defendant's conduct was consistent with industry practice and the purpose of demand response. Matter settled.
- **Valuation of Alleged Misrepresentations of Demand Response Company.** Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony before the American Arbitration Association (non-public).
- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice

charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's costs and operating characteristics. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

TARIFF AND RATE DESIGN

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

BUSINESS STRATEGY

- **Preparing a Gentailer for a Transformed Wholesale Market Design.** Supported a gentailer in Alberta to prepare its generation and retail businesses for the implementation of a capacity market.
- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility, evaluated a venture to build and operate cogeneration facilities. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Helped draft RFPs and develop negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance its trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the value client could bring to each customer. Worked with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a utility, performed a market assessment for DG technologies by segment in the U.S.
- **Fuel Cells**. For a fuel cell manufacturer, provided electricity market analysis to inform a market entry strategy in the U.S.

ARTICLES & PUBLICATIONS

- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 1: Foundation of Resource Accreditation, report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).

- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 2: Options for New England report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).
- *Offshore Wind Transmission: An Analysis of Options for New York*, report prepared for Anbaric, August 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- *Singapore Forward Capacity Market—FCM Design Proposal (third Consultation Paper)*, prepared for the Singapore Energy Market Authority, May 2020 (with J. Chang and W. Graf). Followed draft proposals in first and second Consultation papers in May 2019 and Dec 2019.
- *Quantitative Analysis of Resource Adequacy Structures*, report prepared for NYSERDA and NYSDPS, July 1, 2020 (with K. Spees, J. Imon Pedtke, and M. Tracy). Update to version from May 29, 2020.
- New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040 Including Alternative Scenarios, report prepared for NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Crocker Ross, and J. Moraski). Update to version from May 18, 2020.
- *Qualitative Analysis of Resource Adequacy Structures for New York*, report prepared for NYSERDA and NYSDPS, May 19, 2020 (with K. Spees and J. Imon Pedtke).
- *Offshore Transmission in New England: The Benefits of a Better-Planned Grid*, report prepared for Anbaric, May 2020 (with J. Pfeifenberger and W. Graf).
- *Implementing Recommended Improvements to Market Power Mitigation in the WEM*, report prepared for Energy Policy WA in Western Australia, April 2020 (with T. Brown).
- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, report prepared for PJM, March 17, 2020 (with M. Hagerty, S. Sergici, E. Cohen, S. Gang, J. Wroble, and P. Daou).
- "Forward Clean Energy Markets: A New Solution to State-RTO Conflicts," *Utility Dive*, January 27, 2020 (with K. Spees and J. Pfeifenberger.)
- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes: Expanded Report Including a Detailed Market Design Proposal, report prepared for NRG, September 2019 (with K. Spees, W. Graf, and E. Shorin).
- *International Review of Demand Response Mechanisms in Wholesale Markets*, report for the Australian Energy Market Commission, June 2019 (with T. Brown, K. Spees, and C. Wang).

- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes, report prepared for NRG, April 2019 (with K. Spees, W. Graf, and E. Shorin).
- *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, Final Draft*, prepared for the Electric Reliability Council of Texas, December 20, 2018 (with R. Carroll, A. Kaluzhny, K. Spees, K. Carden, N. Wintermantel, and A. Krasny).
- Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively, discussion paper, July 2018 (with K. Spees, J. Pfeifenberger, and J. Chang).
- *Fourth Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 16, 2018 (with J. Pfeifenberger, K. Spees, and others).
- *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Michael Hagerty, J. Pfeifenberger, S. Gang of Sargent & Lundy, and others).
- *Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule*, whitepaper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel).
- *Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions*, report prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, D.L. Oates, T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke).
- *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals*, whitepaper prepared for the New York Independent System Operator, August 11, 2017 (with R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee).
- "How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees).
- *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, whitepaper prepared for the Public Utilities Office in the Government of W. Australia's Department of Finance, September 1, 2016 (with T. Brown, W. Graf, J. Reitzes, H. Trewn, and K. Van Horn).
- *Western Australia's Transition to a Competitive Capacity Auction*, report prepared for Enernoc, January 29, 2016 (with K. Spees and C. McIntyre).

- *Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal*," report prepared for ERCOT, December 2015 (with R. Carroll, P. Ruiz, and W. Gorman).
- Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint—Options for MISO, Utilities, and States, report prepared for NRG, November 9, 2015 (with K. Spees and R. Lueken).
- *International Review of Demand Response Mechanisms*, report prepared for Australian Energy Market Commission, October 2015 (with T. Brown, K. Spees, and D.L. Oates).
- Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism, report prepared for EnerNOC, Inc., August 2014 (with K. Spees).
- *Third Triennial Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).
- *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pfeifenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).
- *Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).
- *Estimating the Economically Optimal Reserve Margin in ERCOT*, report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees, and I. Karkatsouli).
- "Capacity Markets: Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy*. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger and K. Spees).
- *ERCOT Investment Incentives and Resource Adequacy*, report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).
- "Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" *Public Utilities Fortnightly*, December 2011 (with J. Pfeifenberger).
- Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15, prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees).

- *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).
- "Fostering economic demand response in the Midwest ISO," *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).
- "DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.
- Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements, report prepared for MISO, January 2010 (with K. Spees and A. Hajos).
- Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design, report prepared for MISO, January 2010 (with A. Hajos).
- *Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market*, whitepaper for the NYISO and stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).
- *Fostering Economic Demand Response in the Midwest ISO*, whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).
- *Review of PJM's Reliability Pricing Model (RPM)*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).
- "Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).
- Enhancing Midwest ISO's Market Rules to Advance Demand Response, report written for MISO, March 12, 2008 (with R. Earle).
- "The Power of Five Percent," *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).
- Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).
- *Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets*, Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).
- "Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).

- *Quantifying Demand Response Benefits in PJM*, study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).
- "Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).
- "Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Observations and Implications of the 2021 Texas Freeze," presented to Power Markets Today webinar on the February 2021 ERCOT electricity failure, April 14, 2021.
- "Offshore Wind Transmission: An Analysis of Options for New York," presented at LCV Virtual Policy Forum, August 6, 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- "Possible Paths Forward from MOPR," presented to Power Markets Today webinar on "Capacity Market Alternatives for States," July 15, 2020.
- "Considerations for Meeting Sub-Annual Needs, and Resource Accreditation across RTOs," presented to MISO Resource Adequacy Subcommittee, July 8, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "New York's Evolution to a Zero Emission Power System—Modeling Operations and Investment through 2040 Including Alternative Scenarios," presented to NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Ross, and J. Moraski).
- "Singapore Foreward Capacity Market Design—Industry Briefing Sessions," presented via video to Singapore electricity market stakeholders, June 5&9, 2020 (with W. Graf).
- "Industry Changes in Resource Adequacy Requirements," presented to MISO Resource Adequacy Subcommittee, May 6, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," presented to NYISO Stakeholders, March 30, 2020 (with R. Lueken, J. Weiss, J. Moraski, and S. Ross).
- "Electricity Market Designs to Achieve and Accommodate Deep Decarbonization," presented to Advanced Energy Economy (AEE) video conference, "ISO-NE in 2050: Getting To An Advanced Energy Future In New England," March 18, 2020.

- "U.S. Offshore Wind Generation, Grid Constraints, and Transmission Needs," presented at Offshore Wind Transmission, USA Conference, September 18, 2019 (with J. Pfeifenberger and K. Spokas).
- "Pollution Pricing in the Power Sector: Market-Friendly Tools for Incorporating Public Policy," presented to GCPA Spring Conference, Houston, TX, April 16, 2019.
- "The Transformation of the Power Sector to Clean Energy: Economic and Reliability Challenges," keynote address to the Power Engineers 4th Annual Power Symposium, Weehawken, NJ, April 4, 2019.
- "Market Design for Winter Energy Security in New England: Further Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).
- "Market Design for Winter Energy Security in New England: Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, January 9, 2019 (with D.L. Oates).
- "Market Equilibrium Reserve Margin in ERCOT," presented to Power Markets Today webinar, "A Post Summer Check-in of ERCOT's Market," October 31, 2018.
- "Carbon Pricing in NYISO's Wholesale Energy Market, and Applicability to Multi-State RTO markets," presented to Raab Policy Roundtable, May 23, 2018; presented to the Energy Bar Association, 2018 EBA Energizer: Pricing Carbon in Energy Markets, June 5, 2018; presented to Bank of America Merrill Lynch, June 25, 2018.
- "Reconciling Resilience Services with Current Market Design," presented to RFF/R-Street Conference on "Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System," Washington, D.C., May 30, 2018.
- "System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches," presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.
- "Natural Gas Reliability: Understanding Fact from Fiction," panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).
- "Carbon Pricing in Wholesale Markets: Takeaways from NYISO Carbon Charge Study," presented to Harvard Electric Policy Group, October 12, 2017.

- "Pricing Carbon into NYISO's Wholesale Energy Market: Study Overview and Summary of Findings," presented to NYISO Business Issues Committee, September 12, 2017.
- "Carbon Adders in Wholesale Power Markets—Preventing Leakage," panelist at Resources for the Future's workshop on carbon pricing in wholesale markets, Washington, D.C., August 2, 2017.
- "Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.
- "ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.
- "The Future of Wholesale Electricity Market Design," presented to Energy Bar Association 2016 Annual Meeting & Conference, Washington, DC, June 8, 2016.
- "Performance Initiatives and Fuel Assurance—What Price Mitigation?" presented to Northeast Energy Summit 2015 Panel Discussion, Boston, MA, October 27, 2015.
- "PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).
- "Energy and Capacity Market Designs: Incentives to Invest and Perform," presented to EUCI Conference, Cambridge, MA, September 1, 2015.
- "Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.
- Before the Arizona Corporation Commission, Commission Workshop on Integrated Resource Planning, Docket No. E-00000V-13-0070, presented "Perspectives on the IRP Process: How to get the most out of IRP through a collaborative process, broad consideration of resource strategies and uncertainties, and validation or improvement through market solicitations," Phoenix, AZ, February 26, 2015.
- "Resource Adequacy in Western Australia—Alternatives to the Reserve Capacity Mechanism (RCM)," presented to The Australian Institute of Energy, Perth, WA, October 9, 2014.
- "Customer Participation in the Market," panelist on demand response at Gulf Coast Power Association Fall Conference, Austin, TX, September 30, 2014.

- “Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy,” presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.
- “EPA’s Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d),” presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.
- “Capacity Markets: Lessons for New England from the First Decade,” presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.
- “The State of Things: Resource Adequacy in ERCOT,” presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.
- “Resource Adequacy in ERCOT,” presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.
- “Electricity Supply Risks and Opportunities by Region,” presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.
- “Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response,” presented to the Cadwalader Energy Investor Conference, New York, NY, February 7, 2013 (with K. Spees).
- “The Resource Adequacy Challenge in ERCOT,” presented to The Texas Public Policy Foundation’s 11th Annual Policy Orientation for legislators, Austin, TX, January 11, 2013.
- “Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives,” presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.
- “Resource Adequacy in ERCOT,” presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.
- “Texas Resource Adequacy,” presented to Power Across Texas, Austin, TX, September 21, 2012.
- “Resource Adequacy and Demand Response in ERCOT,” presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.
- “Summary of Brattle’s Study on ‘ERCOT Investment Incentives and Resource Adequacy’,” presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

- "Market-Based Approaches to Achieving Resource Adequacy," presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.
- "Fundamentals of Western Markets: Panel Discussion," WSPP's Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with J. Weiss).
- "Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.
- "Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.
- Before the PJM Board of Directors and senior level representatives at PJM's General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.
- "Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.
- "Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.
- "Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, TN, May 3, 2007 (with J. Pfeifenberger, presenter).
- "Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.
- "Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.
- "Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.
- "Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

JOHN MICHAEL HAGERTY

Senior Associate

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Mr. John Michael Hagerty is a Senior Associate at The Brattle Group with experience in wholesale market design, resource planning, electrification and deep decarbonization, and transmission planning and development. Michael has worked on several analyses in support of cost of new entry (CONE) estimates for ISO-NE, PJM and the Alberta Electric System Operator (AESO). Michael has also worked for utilities, renewable and storage developers, and state agencies to assess the least cost resources to achieve system reliability and climate goals and the role of specific generation resources to achieve those goals.

Mr. Hagerty received his M.S. in Technology and Policy from the Massachusetts Institute of Technology and his B.S. in Chemical Engineering from the University of Notre Dame. Prior to joining Brattle, Mr. Hagerty was a research assistant at the MIT Energy Initiative, an oil refinery process engineer at Honeywell, and a research chemist at GE Global Research.

AREAS OF EXPERTISE

- Electricity wholesale market design
- Resource planning
- Electrification and deep decarbonization
- Transmission planning and development

EXPERIENCE

Electricity Wholesale Market Design

- **PJM Cost of New Entry Study.** For PJM in 2014, 2018 and 2022, evaluated the most recent market trends for new gas-fired generation, updated specifications of the reference resource, and updated of the Cost of New Entry (CONE) parameter. In addition, evaluated the methodology for estimating the net energy and ancillary services (E&AS) revenues in the Net CONE calculation and proposed revisions and a forward-looking approach.
- **PJM Forward-Looking E&AS Revenues.** For PJM, developed a forward-looking approach to estimating the energy and ancillary service revenues for new resources to use in setting parameters in their capacity market. The forward-looking approach uses electricity futures products with sufficient liquidity in PJM and historical hourly price shapes to develop projected hourly prices that PJM will use in a virtual dispatch of each resource type to estimates their E&AS revenues.

- **MISO Resource Adequacy Market Design.** Advised MISO in its Resource Availability and Need initiative to reform its resource adequacy framework to address year-round shortage risks as the fleet transforms. Presenting to stakeholders on resource accreditation, determination of LSE requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.
- **AESO Cost of New Entry Study.** For the soon-to-be implemented capacity market, evaluated the Alberta-specific drivers of new entry, technologies most recently installed, and applicable financial assumptions. Developed candidate reference technology specifications and currently estimating bottom-up cost estimates. Evaluated pros/cons of E&AS methodology across U.S. capacity markets and proposed forward-looking approach using the best available market data in Alberta.
- **Harmonizing New York's Wholesale Energy Market and Environmental Goals through Carbon Pricing**. Worked with NYISO to: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating charges to customers, border charges to prevent leakage, and interactions with other market design and policy elements; and (2) develop a flexible model to evaluated how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Currently supporting NYISO in detailed market design and stakeholder engagement.
- **ISO-NE Net Cost of New Entry.** For ISO New England, worked with Sargent & Lundy and stakeholders to develop estimates for the Net Cost of New Entry (Net CONE) to which the prices in the demand curve are indexed.
- **ISO-NE Offer Review Trigger Prices.** For the Internal Market Monitor in ISO New England, developed offer review trigger prices for screening for uncompetitively low offers in the Forward Capacity Market. Collaborated with Sargent & Lundy to conduct a bottom-up analysis of the costs of building and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency, and demand response. For each technology, estimated the capacity payment needed to make the resource economically viable, given expected non-capacity revenues, a long-term market view, and a cost of capital. Recommendations were filed with and accepted by the Federal Energy Regulatory Commission (FERC).
- **Fuel Supply and Grid Resilience**. Evaluated the U.S. Department of Energy Notice of Proposed Rulemaking concerning fuel supply and grid resilience. Reviewed and

documented most recent studies that evaluated value of resilience and approaches for developing metrics and processes for increasing system resilience.

Resource Planning

- **Alternative Resource Portfolios for Duke Carbon Plan**. For the Clean Power Suppliers Association, developed least-cost resource portfolios for Duke Energy Carolinas and Duke Energy Progress to achieve 70% reduction in carbon dioxide emissions by 2030 using Brattle's capacity expansion model, GridSIM, specifically analyzing the cost and resource impacts of alternative compliance dates and solar interconnection limits. Submitted written direct testimony and provided oral testimony to the North Carolina Utilities Commission related to our analysis.
- **Benefits of Offshore Wind in California.** For offshore wind developer, analyzed the costs and benefits of offshore wind in California for achieving system-wide reductions in greenhouse gas emissions using GridSIM, including the incremental costs of offshore wind interconnection and avoided costs of onshore transmission upgrades to support onshore resources.
- **Market Value of Pumped Hydro Facility**. For pumped storage developer, analyzed the market value of alternative configurations of a proposed pumped storage facility in California using our internal storage modeling platform, bStore.
- **Value of Community Solar in Arizona**. For Cypress Creek Renewables, developed an estimate of the value of community solar projects to the APS grid to serve as the basis for compensation mechanisms for projects and rates for customers, including the avoided generation costs, avoided transmission and distribution costs, and avoided emissions costs.
- **Wisconsin Coal Retirement Replacement Plan**. For WEC Utilities, submitted testimony to the Wisconsin Public Service Commission in support of the construction of new gas-fired reciprocating internal combustion engine (RICE) and new battery energy storage system (BESS) resources to replace retirement of old coal and gas fired resources.
- **North Carolina Clean Energy Legislation**. For Cypress Creek Renewables, analyzed alternative resource mixes for the Duke Energy Carolinas and Progress service territories that accelerate coal plant retirements and rely more heavily on renewable energy resources and battery storage compared to the 2020 IRP to inform debate on North Carolina clean energy legislation. We simulated the operation of the Duke Energy system using GridSIM, and estimated the generation-related capital and operating costs of a portfolio of resources that

achieves about 70% reductions in GHG emissions. We also analyzed alternative approaches to securitization of the net book value of several retiring coal plants.

- **Rhode Island 100% Renewable Study.** For the Rhode Island Office of Energy Resources, analyzed the renewable resources necessary to achieve the state's nation-leading goal of 100% renewable generation by 2030, and the implications for ratepayer costs, economic impacts, etc. The study included demand projections through 2030 and through 2050, to account for Rhode Island's near-term and long-term decarbonization objectives, development of alternative renewable resources and portfolios to achieve this target, analysis of long-term market prices using GridSIM, evaluation of the ratepayer cost and economic impact of the alternatives, and assessment of policy mechanisms, planning requirements and equity considerations associated with meeting the goal.
- **Scenario-based Strategic Planning for Generation and Transmission Cooperative.** For a utility, led the senior executive team and board members in developing long-range strategies for the organization, incorporating rate design principles, transmission development strategies, generation deployment, and strategies surrounding emerging technologies and employee retention, training and succession. Also working with the board and senior executives to develop specific strategic initiatives that would guide the organization.
- **Resource Planning.** For a utility in the West, guided a group of cross-functional planning group in assessing future uncertainties, developing future scenarios, developed analytical frameworks and methodologies in analyzing future resource options. Recommendations included using scenario-based and stochastic approaches in analyzing the risks associated with short-term and long-term uncertainties in the market place on the value of the utility's future resources.
- **Renewable Options for Massachusetts:** For the Barr Foundation, reviewed the literature on renewable resource options, synthesized most relevant results, and developed policy recommendations for policy makers in Massachusetts to consider in setting requirements for future low carbon resource procurements. Presented findings at Massachusetts Senate hearing.
- **Reliability Concerns of Clean Power Plan.** For the Advanced Energy Economy Institute, assessed the North American Electric Reliability Corporation's (NERC) initial reliability assessment of the U.S. Environmental Protection Agency's Clean Power Plan, which is designed to lower greenhouse gas emissions from existing power plants. The project involved assessing NERC's review and providing a range of options for providing reliability while complying with the Clean Power Plan.

- **Impediments for Renewable Energy Development in Nebraska.** For the Nebraska Power Review Board, analyzed the potential impediments to greater renewable energy development and provided policy recommendations to the state that wants to pursue more renewable energy development, primarily for export out of the state.
- **Regional Renewable Energy Analysis.** For the State of Connecticut, analyzed the New England renewable energy market including a detailed evaluation of short-term and long-term supply and demand balance of renewable energy in the region, an examination of the supply potential in the region and the potential effect of transmission investment choices on renewable energy development in the region and provided policy recommendations about the procurement of electric power resources for a 10-year horizon, after comparing the potential effects of future scenarios on various resource procurement possibilities.

Electrification and Deep Decarbonization

- **Distribution of EV Demand**. For ERCOT, developing substation-level projections of demand for electric LDVs, MDVs, and HDVs through 2030 to use in their near-term transmission planning process, Regional Transmission Plan.
- **EVs as Distributed Energy Resources**. For a vehicle manufacturer, assessed the distributed energy resource (DER) supply chain and the current competitors to support DERs, analyzed the value of EVs as a DER, and developed strategies for entering the market.
- **Electrification Program Benefit-Cost Analysis**. For Pepco, assessed the benefits and costs of the company's Climate Solutions Plan. The Plan consists of 62 demand-side initiatives, including large energy efficiency, building electrification, and transportation electrification portfolios. The analysis quantified the energy system and environmental benefits of the programs and evaluated the target scale of the impact of the programs. Participated in a series of stakeholder workshops on the study findings and methodology. The final report was filed with the DC PSC.
- **Electrification Peak Load Impacts**. For Pepco, analyzed the peak demand impacts of achieving Washington, DC's decarbonization goals through electrification. The study included analysis of a portfolio of advanced energy efficiency and load flexibility measures to mitigate peak demand growth using our internal economy-wide decarbonization model DEEP model, and concluded that the projected peak demand growth rates would remain within the historical range experienced by the utility.
- **Customer Action Pathway to Decarbonization**. For Oracle Utilities, estimated the reduction in greenhouse gas (GHG) emissions that could occur by 2030 and 2050

if customer adoption of GHG-reducing technologies using our DEEP model, including energy efficiency, rooftop solar, electric vehicles, and electric heat pumps, rises to an aggressive and achievable level.

- **EV Managed Charging Program.** For SRP, developed an updated EV adoption forecast for their territory to inform the potential scale of the managed charging program, analyzed the system-level benefits of managed EV charging to inform the level of customer incentives, including energy and capacity cost savings, and reviewed the design of their pilot study
- **Transportation Electrification Forecast for Resource Planning.** For Portland General Electric, developed electrification adoption forecasts for LDV, MDV, and HDV in their territory, estimated the total demand of transportation electrification, and projected the scale of charging infrastructure necessary to support electrification.
- **New England 2050 Resource Needs**: For the Coalition for Community Solar Access, we conducted a study on the requirements to meet clean energy resource deployment in New England consistent with economy-wide decarbonization targets in the region by 2050 using our DEEP modeling capablity.
- **Transmission Needs in an Electrified Future:** For the WIRES Group, we estimated the scale of nationwide transmission investment that will be necessary to support the electrification of the U.S. economy. In this analysis, we used our DEEP modeling suite to estimate the incremental annual energy demand, peak load impact, and renewable resources necessary in 2030 and 2050 to meet the rising demand across 6 U.S. regions. The modeling includes the ability to estimate hourly demand impacts of various degrees of electrification of energy end uses including transportation, space and water heating as well as at a high-level industrial processes and agriculture.
- **Electrification Cost-effectiveness:** For EPRI, we are currently developing a methodology for evaluating the cost-effectiveness of ratepayer funded electrification programs. Our research involves a review of the literature on demand-side resource cost-effectiveness tests, interviews with industry experts on cost-effectiveness and electrification, and the publication of a report summarizing the findings and key recommendations.
- **2050 Scenario Development for Offshore Wind Developer:** For a potential bidder into an offshore wind procurement in New York, we developed 2050 demand (and resulting regional price) forecasts including 8760 hourly projections of electrification related demand using
- **Electrification – Emerging Opportunities for Utility Growth:** Paper using our internal economy-wide decarbonization model, DEEP, to estimate the technical

potential for electrification of transport and heating in terms of both increases of (utility) electricity sales and GHG emissions reductions. Using a transparent model of the U.S. energy system, the paper estimates that full electrification of both sectors by 2050 could double electricity sales relative to 2015 and reduce economy-wide carbon emissions by over 75% relative to 2015.

- **California GHG Allowance Market Analysis.** For a California utility, analyzed the near- and long-term GHG allowance prices under AB32, which included a comprehensive review of GHG emissions reductions opportunities and cost estimates and development of an integrated approach for projecting GHG allowance prices.

Transmission Planning and Development

- **Transmission Planning Strategy**. For a solar generation developer, provided summary of transmission planning processes in ERCOT, NYISO, PJM and BPA and developed strategy for improving transmission planning processes in each market.
- **Improving Transmission Planning**. For NRDC and ACORE, developed reports to submit to the FERC ANOPR on transmission planning that identify key issues with the current transmission planning process and propose approaches to improve planning to better identify future transmission system needs. We specifically focused on improving the interregional transmission planning process and developed a roadmap that identifies key actions stakeholder can take for identifying interregional transmission needs, quantifying the benefits of those projects, and improving the process for approving them.
- **New Jersey Offshore Wind Transmission**. For the New Jersey Board of Public Utilities, supporting their solicitation of transmission solutions through the PJM State Agreement Approach process that will facilitate their goal of 7,500 MW of offshore wind capacity by 2035.
- **Western U.S. Transmission Benefit-Cost Analysis**. For a major utility in the Western U.S., analyzed the long-term benefits of a multi-billion dollar portfolio of transmission upgrades that will increase access to remote renewable energy resources and greatly expand opportunities for cost effective market transfers across WECC. Developed production cost simulations in PSO that reflect real-world market conditions and analyzed the shifts in renewable energy resources in California and other regions based on the expanded transmission capability.
- **Benefit-Cost Analysis of Ten West Link**: For Starwood Energy, prepared testimony on the economic and policy of the Ten West Link transmission project filed by Brattle Principal Judy Chang to the Arizona Line Siting Committee and the California Public Utilities Commission.

- **Benefits of Path 15 Upgrade in California**: For DATC, prepared testimony to be filed by Brattle Principal Hannes Pfeifenberger to FERC concerning the benefits of the Path 15 Upgrade to the California electric power system.
- **Benefits of MISO MVP Project**: For ATC, prepared testimony to be filed by Brattle Principal Hannes Pfeifenberger to the Wisconsin Public Service Commission concerning the benefits of the Cardinal-Hickory Creek Project to the MISO power system and Wisconsin ratepayers.
- **Competitive Transmission Planning Processes.** For several transmission developers analyzed the scope of competitive transmission planning processes and the potential cost savings and innovations resulting from these processes. Compared the U.S. experience under FERC Order 1000 with the available experience in Canada, the U.K., and Brazil.
- **Benefits of TransWest Express:** For TransWest Express LLC, summarized the benefits of the TransWest Express transmission project to the western power system, Colorado, and the local counties for the purposes of obtaining sufficient right-of-way for the project.
- **Impacts of Northern Pass on New England Markets**: For the New Hampshire Attorney General's Office, evaluated the energy and capacity market benefits and environmental impact of the Northern Pass transmission project, a proposed HVDC transmission line linking the Canadian Province of Quebec with the New England power system.
- **Benefit-Cost Analysis of New York Transmission Upgrades**: For New York Public Service Commission, analyzed potential benefits of more than 15 proposed transmission portfolios. Benefits analysis included production cost savings, capacity resource savings, avoided reliability upgrades, and reduced costs of meeting renewable/climate goals. Each transmission portfolio analyzed both from a societal (NPV) perspective and a ratepayer perspective.
- **Quadrennial Energy Review Electricity Baseline Analysis**: For PNNL and the U.S. Department of Energy, reviewed and summarized major issues concerning infrastructure across the electric power sector and, in particular, current trends in transmission, distribution, and storage infrastructure development and planning and discussed on-going challenges to building a more reliable and efficient electric power system.
- **Developed Process for Using Scenario-based Approach for Transmission Planning.** For the Electric Reliability Council of Texas (ERCOT), developed and led ERCOT and stakeholder sessions in developing future scenarios appropriate for long-term transmission planning.

- **Evaluation of Transmission Planning and Benefits Metrics.** For The Electric Reliability Council of Texas (ERCOT), reviewed, assessed, and developed recommendations for: 1) improvements in planning process, 2) methods for evaluating the long-term costs and benefits, and 3) improvements in system simulations. These recommendations are used to develop an improved business case for transmission.
- **Transmission Planning and Benefits/Costs Analyses.** For WIRES, a trade group of transmission companies, authored a peer-reviewed whitepaper outlining the industry practices for methodologies for evaluating the benefits and costs of economic transmission projects; and present a scenario-based approach to transmission planning.
- **Benchmarking of the Impact of Regulatory Processes on Transmission Costs.** For an international transmission company, analyzed the potential impact of the differences associated with jurisdictional and regulatory process on transmission project costs.

TESTIMONY

Before the North Carolina Utilities Commission, Docket No. E-100, Sub 179, *Oral Testimony of John Michael Hagerty on behalf of Clean Power Suppliers Association*, in the matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan, September 26, 2022.

Before the North Carolina Utilities Commission, Docket No. E-100, Sub 179, *Direct Testimony of John Michael Hagerty on behalf of Clean Power Suppliers Association*, in the matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan, September 2, 2022.

Before the Public Service Commission of Wisconsin, Docket No. 5-CE-153, *Oral Testimony of John Michael Hagerty on behalf of Wisconsin Public Service Corporation and Wisconsin Electric Power Company*, regarding Joint Application of Wisconsin Public Service Corporation and Wisconsin Electric Power Company for Authority to Construct the Weston Reciprocating Internal Combustion Engine Project in the Villages of Rothschild and Kronenwetter, Marathon County, Wisconsin, January 2022.

Before the Public Service Commission of Wisconsin, Docket No. 5-BS-254, *Rebuttal Testimony of John Michael Hagerty*, prepared for Wisconsin Electric Power Company and Wisconsin Public Service Corporation, regarding Joint Application of Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Madison Gas and Docket Electric Company for Approval to Acquire Ownership Interests in the Paris Solar Generating and Battery Energy

Storage System, December 2021.

Before the Public Service Commission of Wisconsin, Docket No. 5-CE-153, *Direct Testimony of John Michael Hagerty on behalf of Wisconsin Public Service Corporation and Wisconsin Electric Power Company*, regarding Joint Application of Wisconsin Public Service Corporation and Wisconsin Electric Power Company for Authority to Construct the Weston Reciprocating Internal Combustion Engine Project in the Villages of Rothschild and Kronenwetter, Marathon County, Wisconsin, September 2021.

Before the Public Service Commission of the District of Columbia, Formal Case No. 1167, *An Assessment of Electrification Impacts on the Pepco DC System*, prepared for Pepco Holdings, Inc. (with R. Hledik, S. Sergici, and J. Olszewski), August 27, 2021.

Before the Federal Energy Regulatory Commission, Docket No. ER21-424, *Prepared Direct Testimony of Dr. Jurgen Weiss and John M. Hagerty,* November 12, 2020. Attachment A to *Application for Authorization to Recovery Costs Associated with an Electric Vehicle Infrastructure Pilot Project*, November 12, 2020.

Before the Federal Energy Regulatory Commission, Docket No. ER20-2308, *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty* on behalf of LS Power, *re:* Comments in Support of PJM Stakeholder Approved Section 205 Filing (for treatment of End of Life Projects), July 23, 2020.

Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), *Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* June 1, 2020. Attachment D to *Second Compliance Filing concerning Application of the Minimum Offer Price Rule*, June 1, 2020.

Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), *Supplemental Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* March 25, 2020. Attachment to *Re: PJM Interconnection, L.L.C., Docket Nos. EL16-49, EL18-178, ER18-1314 Errata to PJM Compliance Filing re: Hope Creek Nuclear Plant*, March 25, 2020.

Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), *Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* March 18, 2020. Attachment D to *Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for an Extended Comment Period of at least 35 Days*, March 18, 2020.

Before the Public Utilities Commission of California, Application 16-10-12, *Ten West Link Economic and Public Policy Benefits and Costs Analysis, Technical Report*, prepared for DCR Transmission LLC (with J. Chang., J. Pfeifenberger, M. Tracy, and J.I. Pedtke), December 20, 2019.

Before the Alberta Utilities Commission, Proceeding #23757, Oral Testimony on behalf of the

Alberta Electric System Operator re: Alberta Electric System Operator Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, April 30 to May 3, 2019.

Before the Alberta Utilities Commission, Proceeding #23757, *Demand Curve and Energy and Ancillary Services Offset: Response to Intervener Evidence in Alberta Utilities Commission Proceeding #23757*, prepared by Kathleen Spees, J. Michael Hagerty, Cathy Wang, and Matthew Witkin, April 11, 2019, Appendix "A" to *Rebuttal Evidence of the Alberta Electric System Operator,* April 12, 2019.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Answering Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C regarding Cost of New Entry Parameters*, December 14, 2018, Attachment A to *Answer of PJM Interconnection, L.L.C. to Protests and Comments*, December 17, 2018.

Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, *Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C* November 5, 2014. Attachment E to *Re: Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters*, November 6, 2014.

PUBLICATIONS

- "Community Solar Value Stack in Arizona," (with A. Ramakrishnan, et al.), prepared for Cypress Creek Renewables, August 30, 2022.
- "PJM CONE 2026/2027 Report," (with S. Newell, et al.), prepared for PJM Interconnection, April 21, 2022.
- "Pepco's Climate Solutions 5-Year Action Plan: Benefits and Costs", (with R. Hledik, S. Sergici), prepared for Pepco Holdings, Inc., February 4, 2022.
- "A Roadmap to Improved Interregional Transmission Planning," (with J. Pfeifenberger, K. Spokas, J. Tsoukalis), prepared for Natural Resource Defense Council, November 30, 2021.
- "The Customer Action Pathway to National Decarbonization," (with S. Sergici, R. Hledik, K. Peters, and A. Faruqui), prepared for Oracle Utilities, October 21, 2021.
- "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," (with J. Pfeifenberger, K. Spokas, J. Tsoukalis), prepared for ACORE and Natural Resource Defense Council, October 13, 2021.
- "A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation", (with M. Celebi, M. Witkin, J. Olszewski, and F. Corpuz), prepared for Cypress Creek Renewables, August 31, 2021.

- "Target – Plan – Finance: A Framework for Climate Policy in Federal Infrastructure Legislation, A Discussion Draft", (with P. Fox-Penner, K. Spokas, G. Jones, A. Gutner-Davis, and R. Janakiraman), July 2021.
- "SWIP-North Benefits Analysis", (with J. Pfeifenberger and E. Bennett), prepared for Great Basin Transmission, February 2021.
- "The Road to 100% Renewable Electricity by 2030 in Rhode Island", (with D. Murphy and J. Weiss), prepared with Rhode Island Office of Energy Resources, January 13, 2021.
- "Electricity Transmission and Railroads: A Synergy of Needs and Right-of-Ways, (with J. Pfeifenberger)", prepared for Rail Electrification Council, November 19, 2020.
- "Considerations for Meeting Sub-Annual Needs and Resource Accreditation across RTOs", (with S. Newell, J. Pfeifenberger, and W. Graf), prepared for MISO Resource Adequacy Subcommittee, July 8, 2020.
- "Getting to 20 Million EVs by 2030: Opportunities for the Electricity Industry in Preparing for an EV Future", (with S. Sergici and L. Lam), June 2020.
- "Industry Changes in Resource Adequacy Requirements, Metrics, and Design Elements, (with S. Newell, J. Pfeifenberger, and W. Graf)", prepared for MISO Resource Adequacy Subcommittee, May 6 and May 20, 2020.
- "Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency", (with Samuel A. Newell, Sanem Sergici, Jesse Cohen, Sang H. Gang, John Wroble, Patrick S. Daou), prepared for PJM Interconnection, March 17, 2020.
- "Reaching Climate Goals via Electrification Requires Foot on the Accelerator," (with Jurgen Wess), published by Public Utilities Fortnightly, February 2020.
- "A New Paradigm for Utilities: Electrification of the Transportation and Heating Sectors," (with Ryan Hledik, Ahmad Faruqui, Jürgen Weiss, Michael Hagerty, and Long Lam), published by the American Bar Association, November 2019.
- "Achieving 80% GHG Reduction in New England by 2050: Why the Region Needs to Keep its Foot on the Clean Energy Accelerator," (with Jurgen Weiss, Maria Castaner, and John Higham), prepared for the Coalition for Community Solar Access, September 2019.
- "The Total Value Test: A Framework for Evaluating the Cost-Effectiveness of Efficient Electrification," (with Ryan Hledik, Ahmad Faruqui, and John Higham), prepared with the Electric Power Research Institute, August 2019.

- "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," (with Judy Chang, Hannes Pfeifenberger, Akarsh Sheilendranath, Simon Levin, and Wren Jiang), prepared for LSP Transmission Holdings, LLC, April 2019.
- "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid," (with Jurgen Weiss and Maria Castaner), prepared for WIRES Group, March 2019.
- "AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date," (with Johannes Pfeifenberger, Kathleen Spees, Mike Tolleth, Martha Caulkins, Emily Shorin, Sang Gang, Patrick Daou, and John Wroble), prepared for Alberta Electric System Operator, September 2018.
- "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," (with Samuel Newell, Johannes Pfeifenberger, Bin Zhou, Emily Shorin, Perry Fitz, Sang Gang, Patrick Daou, and John Wroble), prepared for PJM Interconnection, April 2018.
- "Fourth Review of PJM's Variable Resource Requirement Curve," (with Samuel Newell, David Luke Oates, Johannes Pfeifenberger, Kathleen Spees, John Imon Pedtke, Matthew Witkin, and Emily Shorin), prepared for PJM Interconnection, April 2018.
- "The Future of Cap-and-Trade Program in California: Will Low GHG Prices Last Forever?," (with Yingxia Yang, Ashley Palmarozzo, Hannah Sheffield, Metin Celebi, Marc Chupka, and Frank C. Graves), December 2017.
- "Modelling Enhancements for CAISO Transmission Planning: The Feasibilty and Value of Incorporating Scheduling Constraints into CAISO's Planning Model," (with Judy Change, Johannes Pfeifenberger, Kai Van Horn, John Imon Pedtke, and Jesse Cohen), prepared for LS Power, October 2017.
- "Blending In: The Role of Renewable Fuel in Achieving Energy Policy Goals," (with Marc Chupka and Philip Verleger Jr.), prepared for Growth Energy, August 2017.
- "Electrification: Emerging Opportunities for Utility Growth," (with Jurgen Weiss, Ryan Hledik, and Will Gorman), January 2017.
- "Valuation of Electric Power System Services and Technologies," (with M. Kintner-Meyer, J. Homer, P. Balducci, M. Weimar, Ira Shavel, Nicholas Powers, Yingxia Yang and Roger Lueken), prepared for U.S. Department of Energy, August 2016.
- "Peeking Over the Blendwall: An Analysis of the Proposed 2017 Renewable Volume Obligations," (with Marc Chupka, Nicholas Power, and Sarah Germain), prepared for Growth Energy, July 2016.

- "Clean Energy Resource Options for Massachusetts to Meet GHG Reduction Goals under the Global Warming Solutions Act (GWSA): A Synthesis of Relevant Studies," (with Judy Chang and Will Gorman), prepared for the Barr Foundation, June 2016.
- "Benefits of the Southwest Intertie Project-North," (with Johannes Pfeifenberger, Judy Chang, Pablo Ruiz and Cady Wiltsie), prepared for Great Basin Transmission, LLC, March 2016.
- "Issue Brief - The Clean Power Plan: Focus on Implementation and Compliance," (with Marc Chupka, Metin Celebi, Judy Chang, Ira Shavel, Kathleen Spees, Jurgen Weiss, Pearl Donohoo-Vallett and Michael Kline), January 2016.
- "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," (with Sam Newell, Bruce Tsuchida, Akarsh Sheilendranath, Nicole Irwin and Lauren Regan), prepared for NYISO and New York Department of Public Service Staff, September 2015.
- "Lake Erie Connector Market Assessment Report," (with Judy Chang, Johannes Pfiefenberger and Akarsh Sheilendranath), prepared for ITC Lake Erie Connector LLC, May 2015.
- "Electricity Baseline Report for the U.S. Power System," (with Ira Shavel, Nicholas Powers and Yingxia Yang), for Pacific Northwest National Laboratory and U.S. Department of Energy, April 2015.
- "EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review," (with Jurgen Weiss, Toshiki Bruce Tsuchida, and Will Gorman), prepared for the Advanced Energy Economy Institute, February, 2015.
- "Nebraska Renewable Energy Exports: Challenges and Opportunities," (with Judy Chang and Johannes Pfeifenberger), prepared for the Nebraska Power Review Board, December 12, 2014.
- "Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment," (with Judy Chang and Johannes Pfeifenberger), prepared for The Electric Reliability Council of Texas (ERCOT), September 30, 2014.
- "Policy Brief - EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," (with Metin Celebi, Kathleen Spees, Samuel A. Newell, Dean M. Murphy, Marc Chupka, Jürgen Weiss, Judy Chang, and Ira H. Shavel), June 2014.
- "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," report prepared for PJM Interconnection, LLC (with S. Newell, K. Spees, J. Pefiefenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy), May 15, 2014.

- "2013 Offer Review Trigger Prices Study," (with Sam Newell and Quincy Lao), October 2013.
- "Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process," (with Judy Chang, Johannes Pfeifenberger, Samuel A. Newell, and Toshiki (Bruce) Tsuchida), prepared for The Electric Reliability Council of Texas (ERCOT), October 2013.
- "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," (with Judy Chang and Johannes Pfeifenberger), prepared for the Working Group for Investment in Reliable and Economic Electric Systems (WIRES), July 2013.
- "Managing Large-Scale Penetration of Intermittent Renewables," (with MIT Energy Initiative), April 2012.

PRESENTATIONS

- "Designing Effective EV Managed Charging Programs," (with S. Sergici and E. Urey), presented to PLMA Electric Transportation Interest Group, October 28, 2021.
- "Achieving 80% GHG Reduction in New England by 2050: Why the region needs to keep its foot on the clean energy accelerator," NECA Renewable Energy Conference, March 2020.
- "Transmission in a Decarbonized and Electrified World," LSI Transmission and Clean Energy in the Northeast, March 2019.
- "The Role of Transmission in the Future Electric Power System," WIRES University Transmission 101, February 2019.
- "On the Path to Decarbonization: Can Electricity Markets Adapt to Meet Carbon Goals in the Western U.S.?," LSI Buying and Selling Electric Power in the West, January 2019.
- "Seeking a Landing Point: Transmission Needs for U.S. Offshore Wind Generation," AWEA Offshore WINDPOWER Conference, October 2018.
- "Battery Storage Development: Regulatory and Market Environments," Philadelphia Area Municipal Analyst Society, January 2018.
- "Long-Term Implications of Negative Prices for West Coast Electricity Markets," LSI Buying & Selling Electric Power in the West, January 2018.
- "Transmission Planning Strategies to Accommodate Renewables," EUCI Renewable Energy Grid Operations, September 2017.

- "Impacts of Oregon's Coal Phase-Out on Coal Plant Economics in the Western U.S.," LSI Oregon's Clean Electricity and Coal Transition Plan, July 2016.
- "Valuation of Electric Power System Services and Technologies," U.S. Department of Energy Technical Workshop on Electricity Valuation, May 2016.
- "EPA CPP Scenarios—What Texas Is Likely to Do, and the Impacts on ERCOT," ERCOT Market Summit 2016 Pre-Summit Briefing, February 2016.
- "The Clean Power Plan: Implications for the Western Interconnect," EUCI Optimizing Carbon Market Mechanisms in the Western Interconnect, January 2016.
- "Electric Sector Investments in a Lower Carbon World," Notre Dame Mendoza School of Business Climate Investing Conference: Transition to a Low Carbon World, September 2015.
- "Nebraska Renewable Energy Export (LB 1115) Study," Nebraska Power Review Board, December 2014.
- "Trends and Benefits of Transmission Investments: Identifying and Analyzing Value," Ecology & Environment, Inc. 2013 Electric Transmission Seminar at Eagle Nest, September 2013.

September 27, 2022

SANG H. GANG

Vice President & Project Director
Sargent & Lundy Consulting Group

Education

- Electrical Engineering Graduate Work—University of Illinois at Urbana-Champaign—2006
- BS Electrical Engineering—University of Illinois at Urbana-Champaign—2003

Registrations

Professional Engineer (Illinois)

Proficiencies

- Power Project Development Support & Owner's Engineering Services
- Power Supply Planning
- Electric Transmission Planning
- Generator Grid Interconnection Planning
- Production Cost Modeling
- Integrated Resource Plans (IRPs)
- Electricity Markets – Capacity, Energy, and Ancillary Services
- Capital, O&M Costs, and Performance Estimates
- Power Project Due Diligence & Lender's Advisory Services
- Electrical System Analysis and Design

Responsibilities

As a Vice President and a Project Director within Sargent & Lundy's Consulting Group, Sang Gang leads a variety of conventional power plant and renewable energy consulting engagements with utility and IPP clients worldwide. Sang leads Sargent & Lundy's utility planning projects including cost and performance evaluation of various generation and interconnection options, long-term power supply planning, power procurement administration, and transmission and distribution planning. Sang also provides support for project development, owner's engineering, technical due diligence, independent engineering, construction monitoring, condition assessment, and technical advisory services for solar PV, onshore & offshore wind, energy storage, gas, nuclear, grid modernization, transmission, and other decarbonization projects throughout the world. He has significant expertise in the evaluation of technology, plant engineering and design, key project contracts, project economics, and performance records.

Sargent & Lundy Experience

Utility Planning and Advisory

Samsung C&T | 2022

Providing technical advisory services on converter and cable designs, as well as being responsible for key power system studies subject to the grid operator's approval for the 1.6-GW HVDC subsea transmission links project in the UAE.

DTE Energy

- 2022 | Provided decommissioning cost estimates for the utility's gas-fired and renewable generators.
- 2021-2022 | Evaluated power systems impacts of multiple retirement scenarios of the utility's coal units.

PJM Interconnection | 2021-2022

Collaborated with the Brattle Group for quadrennial review of cost of new entry (CONE) study for review of PJM's Variable Resource Requirement (VRR) curve.

City of Grand Island | 2021

Performed economic assessment of future generation mix scenarios, including coal, dual fuel gas turbines, reciprocal engines, and combined cycle. Utilizing hourly production cost modeling in PLEXOS.

NYISO | 2021

Performed buyer-side mitigation review of solar and battery energy storage projects bid into the NYISO market.

PJM Interconnection | 2021

Updated labor, equipment, and material costs for the reference technology in each of the EMAAC, SWMAAC, Rest of RTO, and WMAAC CONE areas. Filed an affidavit in support of PJM's informational filing to FERC.

Clean Energy USA | 2021

Performed distribution hosting capacity study for potential integration of solar DER interconnections to specific Delaware Electric Cooperative distribution circuits.

PJM Interconnection | 2020

Collaborated with The Brattle Group to analyze the gross avoidable costs rates (ACRs) for several types of existing generation including single-unit nuclear, multi-unit nuclear, coal, gas-fired combined-cycle, gas-fired combustion turbines, onshore wind, utility-scale solar PV, and behind-the-meter diesel generators. Our analysis helped PJM implement the December 2019 FERC order to expand the application of its Minimum Offer Price Review (MOPR) in its forward capacity market.

Indianapolis Power & Light Company | 2019–2020

Prepared, managed, and reviewed the results of an all-source RFP to obtain new supply-side electric capacity resources. The work included the complete preparation of the RFP package, analysis and review of the proposed power purchase contracts, interfacing with bidders through the process, development of both qualitative and quantitative bid evaluation methodologies, administration support for the RFP process, bid evaluation from technical and economic perspectives, and bid negotiation.

Northern Indiana Public Service Company | 2019–2020

Preparing a business case report for NIPSCO to support the utility's filing to the Indiana Utility Regulatory Commission to address the replacement of aging T&D infrastructure and grid modernization investments over a seven-year period. Sargent & Lundy is also preparing project scoping documents and cost estimates while maintaining a detailed database of the projects to facilitate planning and regulatory filings.

PSEG Long Island | 2020

Assisting PSEG Long Island in their 2020 Energy Storage RFI and RFP process. Sargent & Lundy's scope includes preparation of RFI/RFP document, managing the entire RFI/RFP process, qualitative and quantitative bid evaluations, and support during project selection and contract negotiations.

Confidential Clients

- 2020-2022 | Technical advisor for a bidder consortium for a 1.6-GW HVDC subsea transmission links project in the UAE. Supported from bid development stage through financial close.
- 2021-2022 | Performed production-cost model-based transmission congestion and solar PV generation curtailment analyses for multiple projects in California and Texas.
- 2021 | Evaluated economic feasibility of BESS addition to the operating onshore wind project in Texas by performing production-cost model-based generator curtailment analysis and BESS cost-benefit analysis.
- 2021 | Performed competitor analysis in support of a bidding strategy for the NY Bight offshore lease areas BOEM auction.

- 2020 | Performed detailed power flow study to support long-term T&D upgrade planning for the anticipated electrical power capacity increase at the client's electrical distribution system. The study entailed steady state N-0 and N-1 contingency load flow analysis and N-1-1 transient stability analysis to identify violating conditions and propose optimal mitigating solutions.
- 2020 | Collaborated with The Brattle Group to assess the technical and economic attractiveness of energy storage deployment options in preparation of the 3.1-GW energy storage target by 2035 in Virginia. Sargent & Lundy performed technical assessment of various energy storage technology options beyond lithium-ion, their technology maturity, performance characteristics, current costs, and a range of scenarios around potential future cost decline rates.
- 2019 | Supported a utility in their transmission planning by evaluating alternative generation and transmission solutions to mitigate areal overload conditions. Worked involved in detailed modeling and analysis using ISO grid model.
- 2018 | Performed engineering and economic evaluation of the client's electric power system with respect to a potential shutdown of a major generation asset. The engineering evaluation included reviews of the capital expenditure plans, fixed and variable O&M numbers, and various performance metrics such as availability, forced outages, and heat rates, which were all used as inputs to the economic model. The economic evaluation calculated breakdowns of various energy production costs such as market purchases/sales, fuel costs, variable O&M costs, and other fixed costs.

Arizona Electric Power Cooperative, Inc. (AEPCO) | 2019

Provided detailed capital cost, O&M cost, and performance estimates for different candidate resource types including simple cycle frame-type gas turbine, aeroderivative gas turbine, reciprocal internal combustion engine, and combined cycle gas turbine projects. Our deliverables were provided as input to the client's long-term resource planning.

Alberta Energy System Operator (AESO) | 2019

Provided technical and legal support to AESO related to its filing to the Alberta Utilities Commission on the design of the Alberta capacity market.

Lansing Board of Water and Light (BWL) | 2019

Supported the BWL Transmission and Distribution Engineering Department in development and completion of seven Asset Life Cycle Plan documents, which contain information regarding the characteristics, performance, condition, maintenance, modeling, and the proposed management plan.

Alberta Energy System Operator (AESO) | 2018

Worked with the Brattle Group to perform cost of new entry (CONE) study in preparation of AESO's inauguration of capacity market.

PJM Interconnection | 2017–2018

Worked with the Brattle Group to perform cost of new entry (CONE) study for review of PJM's Variable Resource Requirement (VRR) curve, which is an administratively determined representation of a demand curve for capacity used in the PJM Reliability pricing Model auction.

Sikeston Board of Municipal Utilities | 2017

Performed an evaluation of the costs and benefits of the client's existing interconnection configuration and alternative interconnection options.

United States Realty | 2013

US Steel Keystone Industrial Port Complex (KIPC)

Performed high-level condition assessment and valuation of the 30-MW KIPC electrical distribution system and developed cost optimization plan.

Renewable and Energy Storage

Dominion Energy | 2021-2022

Providing Owner's Engineering support for the utility's battery energy storage projects. Our support includes EPC technical specification, selection, negotiation, and design reviews during the execution stage.

Aypa Power

- 2022 | Providing Owner's Engineering support for a 100 MW battery energy storage project in California.
- 2021-2022 | Providing Owner's Engineering support for 150 MW battery energy storage project in Texas.

Hydrostor

- 2022 | Prepared IE report for the A-CAES projects in California in support of a DOE loan guarantee application
- 2021 | Provided Owner's Engineering support for two utility-scale battery energy storage projects in California.

Apex Clean Energy | 2021-2022
Prepared generic EPC technical specification for utility-scale battery energy storage projects.

AES Clean Energy

- 2022 | Prepared ISO-NE generator interconnection application for a solar project.
- 2021 | Prepared NYISO generator interconnection applications for multiple solar projects.

Dominion Energy | 2019-2020
Supported development of battery energy storage pilot projects. Scope included review of potential project candidates, preparation of EPC technical specification, and review of EPC bids.

Lincoln Clean Energy | 2019
Provided owner's engineering services to support conceptual layout design optimization, tracker technology selection, and EPC bid solicitation for the 400-MW 2W Permian Solar Project. Also provided owner's engineering services to support EPC bid solicitation for the 40-MW/40-MWh battery energy storage systems to be co-located with the Permian Solar Project.

Confidential Clients
- 2021-2022 | Performing audit of the Plant Accounting and Settlement System including solar performance model at a solar PV facility in the UAE
- 2021-2022 | Performing electrical design verification studies of the client's 800+ MW and 1200+ MW offshore wind projects.
- 2020 | Evaluated compliance of an 800+ MW offshore wind project with the interconnecting utility's reactive power requirements.
- 2020 | Performed a technical due diligence review of a 50-MW/200-MWh battery energy storage system in support of potential asset acquisition.
- 2020 | Prepared MISO interconnection application and supplemental technical requirements for 400-MW solar PV + 200-MW/800-MWh battery energy storage project.
- 2019 | Evaluated the impact of interconnecting the client's offshore wind project to the NYISO grid by performing System Reliability Impact Study.
- 2018 | New York & New Jersey, United States | Worked with NERA Economic Consulting to support a major offshore wind developer by performing competitor bid analyses for offshore wind auctions. Sargent & Lundy's scope included evaluation of potential interconnection points and estimates of capital costs, O&M cost, and annual generation levels.

- 2018 | Mexico | Owner's engineer for a new 100-MW solar PV project. Supported EPC and O&M contract negotiations and preliminary site and technology evaluations.
- 2018 | Prepared CAISO interconnection applications and supplemental technical requirements for 100+ MW solar PV + battery energy storage projects.
- 2018 | Prepared MISO interconnection application and supplemental technical requirements for 100+ MW solar PV project.
- 2018 | Michigan, United States | Performed GIS-based site identification study for multiple small utility-scale solar PV projects.
- 2017 | Georgia, United States | Performed technical due diligence review of two 60-MW biomass projects for potential asset acquisition.
- 2016 | United States | Developed conceptual layout, preliminary electrical design, equipment selection, energy production, detailed capital cost estimates, and LCOE calculation for a 20-MW solar PV project being developed in conjunction with reciprocal engine project.
- 2016 | United States | Developed conceptual layout, energy production, capital cost estimates and expenditure schedule for 20-MW solar PV project being developed adjacent to existing coal-fired power plant.
- 2016 | Performed market study and financial evaluation of adding a battery energy storage system to an existing wind project in the PJM region by assessing the new PJM capacity performance market to evaluate the battery system economics.
- 2016 | California | Performed technical and financial feasibility study of adding a battery energy storage system to the existing metropolitan railway system in San Francisco.

Inter-American Development Bank | 2015

Chile | Performed technical due diligence of a 100-MW single-axis tracking solar PV project.

Electric Power Research Institute (EPRI)

- 2014 & 2015 | Developed utility-scale performance and financial models of various PV technologies to update the EPRI Report, "Solar Energy Technology Guide - 3002001638."
- 2013 | Developed utility-scale performance models of various PV technologies to update the EPRI Report, "Engineering and Economic Evaluation of Central-Station Solar Photovoltaic Power Plant."

TerraForm Power | 2015

Ontario, Canada | Performed technical due diligence to support asset acquisition of two 10-MW solar PV projects.

International Finance Corporation
San Carlos Solar PV Projects

- 2015 | Performed operations monitoring of the three projects
- 2014 | Philippines | Performed independent solar resource and energy yield assessments and technical due-diligence reviews of three solar PV projects—22-MW, 18-MW, and 22-MW.

Overseas Private Investment Corporation

- 2015 | Jamaica | Content Solar PV Project
  - Performed pre-construction technical due diligence of a 22-MW solar PV project.
- 2015 | El Salvador | Real El Salvador Solar PV Project
  - Performed independent energy yield assessments to support financing of a portfolio of eight solar PV projects.
- 2014 | Pakistan | Confidential Wind Project
  - Performed Independent Engineering review of wind resource and energy yield assessment for a 50-MW wind project.
- 2013 | Tanzania | Confidential Solar PV Project
  - Performed Independent Engineering reviews of the solar resource, project financial projections, contract reviews, PV technology, independent design reviews, market pricing review, and O&M approach of a 3-MW solar PV project.

Macquarie Capital | 2013
Simon Solar PV Project
Performed lender’s technical due diligence review of a 30-MW solar PV project in Georgia.

Standard Bank of South Africa

- 2013 | South Africa | Beaufort West PV Project
  - Performed Independent Engineering review of projected energy yield model of a 60-MW solar PV project.
- 2013 | South Africa | MetroWind Project
  - Performed Independent Engineering review of construction progress of a 27-MW wind project.

NextEra Energy Resources, LLC

- 2015 | Texas, United States | Javelina Wind Project
  - Performed Independent Engineering balance-of-plant reviews of a 250-MW wind project.
- 2013 | Texas, United States | Red River Portfolio
  - Performed Independent Engineering balance-of-plant reviews and compliance review of interconnection requirements of two commercially operating wind farms (255 MW total) to support re-financing.
- 2013 | Nebraska, United States Steele Flats Wind Projects
  - Performed Independent Engineering balance-of-plant reviews of a 75-MW wind project.

Gas and Coal Power

Venture Global LNG

- 2022 | Plaquemines LNG Export Facility | Performed transient stability analysis for the off-grid LNG liquefaction facility electrical system in Louisiana.
- 2019 | Calcasieu Pass LNG Export Facility | Supported Venture Global LNG in performing various power system modeling and studies of the off-grid electrical system for an LNG liquefaction facility in Louisiana.

Mirfa International Power and Water Company | 2015–2016

Mirfa Independent Water and Power Plant

Performed plant reliability assessment study through engineering assessment of the equipment operation and past failures history.

Confidential Clients

- 2022 | Provided IPP bid development support for a 800-MW combined cycle and LNG terminal project in Dominican Republic.
- 2022 | Provided IPP bid development support for a 2000+MW IWPP project in Qatar.
- 2021 | Performed technical due diligence for potential acquisition of an operating 2x1 7HA.02 combined cycle power plant in Pennsylvania.
- 2021 | Performed technical due diligence for potential acquisition of a 7HA.03 simple cycle project in New York.
- 2020 | Performed feasibility study to renovate and modernize an existing gas fired CHP boilers to increase the electricity output and continue supplying process steams to the customer.

- 2020 | Qatar | Supported preparation of an IPP bid for a 2300-MW and 100-MIGD project to provide electricity and water to the national utility.
- 2019 | Performed technical advisory services to support development of 800-MW combined cycle power plant and 345-kV transmission line project, including solicitation supports for onshore/offshore site investigations contractor, Power Island OEM, power plant EPC contractor, and substation and transmission EPC contractor.
- 2018 | Performed technical due diligence reviews of 2x300-MW coal plant in operation and 2x660-MW coal plant under construction, in support of potential asset acquisition.
- 2017 | Canada, United States, and Australia | Performed technical due diligence reviews of 16 coal- and gas-fired power plants in support of potential asset acquisition.
- 2017 | Mexico | Performed technical due diligence reviews of Norte-III combined-cycle power project, in support of potential asset acquisition.
- 2016 | United Arab Emirates | Performed technical due-diligence review of four-unit, 2,400-MW coal-fired power plant for potential lenders.
- 2015 | Mexico | Provided Owner's Engineering support for Independent Power Project (IPP) developer's bid to the Comisión Federal de Electricidad (CFE) for Noreste, Topolobampo-II, and Topolobampo-III combined cycle power projects.
- 2013 | Israel | Performed technical due-diligence review of a two-unit, 834-MW combined cycle power project for a potential lender.

Fadhili Plant Cogeneration Company | 2018

Fadhili Combined Heat and Power Project

Performed off-line audit of the Plant Accounting Settlement System and Fuel Demand Model as required by the Power Purchase Agreement (PPA) with one offtaker and Steam and Water Purchase Agreement (SWPA) with the other offtaker.

Dynegy | 2016

Project Manager for Independent Engineering review of four gas-fired combined cycle projects in the U.S.

GNPower Mariveles Coal Plant, Ltd. Co.

- 2016 | Project Manager for new relay setting development and existing relay setting reconstitution.
- 2016 | Project Manager for the LP turbine blade failure assessment.
- 2016 | Project Manager for technical feasibility evaluation of new Generator Circuit Breaker

addition and associated modifications to the plant auxiliary electrical distribution system.

Sithe Global | 2015–2016

Mariveles Coal Power Station

Reviewed major plant remediation program and performed independent engineering review of the two-unit, 300-MW coal-fired power plant in the Philippines for the major equity shareholder of the plant.

Shamal Az-Zour Al-Oula K.S.C. | 2016

Az-Zour North (AZN) Phase 1 Independent Water and Power Project

Project Manager for on-line audit of the Plant Accounting Settlement System and Fuel Demand Model.

Mirfa International Power & Water Company | 2015–2016

Mirfa Independent Water and Power Project

Project Manager for off-line audit of the Plant Accounting Settlement System, Fuel Demand Model, and Outage Mode Model.

Venture Global LNG | 2015–2016

Calcasieu Pass LNG Export Facility

Louisiana, United States | Supported Venture Global LNG as Owner's Engineer in technical feasibility studies such as the transient stability analysis of the off-grid electrical system for an LNG liquefaction facility.

Siddiqsons Energy | 2015

Karachi, Pakistan | Performed feasibility study and prepared technical specifications for developing a 350 MW supercritical coal-fired power plant.

SK Engineering & Construction (SK E&C) | 2014

Jangmoon Combined-Cycle Power Plant

South Korea | Provided technical advisory services to support SK E&C in the review of basic engineering of the two-unit, 2x2x1, 1,820-MW combined-cycle power project.

Korea Sothern Power Company (KOSPO) | 2014

Kelar Combined-Cycle Power Plant

Supported KOSPO as Owner's Engineer in the engineering design review of the 2x2x1, 517-MW combined cycle power project in Chile.

Hyundai Heavy Industries (HHI) | 2013–2014

Jeddah South Thermal Power Plant Stage 1

Saudi Arabia | Provided technical advisory services to support HHI in the basic engineering, detailed engineering, and start-up and commissioning of the four-unit, 2,640-MW supercritical oil-fired thermal power project.

Nuclear Power

Korea Hydro & Nuclear Power (KHNP) | 2016–2019

Project Manager for classroom training program consisting of 20 different technical subject courses in nuclear power plant design and analysis. Each course was offered over 4–8-week durations in the Sargent & Lundy's Chicago office.

KEPCO International Nuclear Graduate School | 2018

Project Manager for one-week long classroom training program about Root Cause Analysis (RCA) and Probabilistic Risk Analysis (PRA).

Dynegy | 2017

Performed due-diligence review of the Comanche Peak Nuclear Power Plant, focusing on identifying any material or major issues associated with the plant and operations that could have a significant cost impact.

Hyundai Engineering Co. (HEC) | 2016

Project Manager for technical advisory services and training program in nuclear power plant steam generator replacement.

Emirates Nuclear Energy Corporation | 2014

Barakah Nuclear Power Plant Units 1 and 2

Performed electrical review of selected safety-related plant systems against licensing basis as part of the Independent Design Review of Barakah Nuclear Plant Units 1 and 2 engineering design.

Tennessee Valley Authority (TVA), Browns Ferry Nuclear Plant

- 2009–2013 | Emergency Diesel Generator Governor Upgrade
- 2012–2013 | NFPA-805: EECW System Circuit Modification
- 2012 | NFPA-805: Emergency Diesel Generator Protective Relay Circuit Modification
- 2012 | LPCI MG Set Abandonment

- 2010–2011 | Service Building Transformer Replacement
- 2010–2012 | Generator Voltage Regulator Replacement
- 2008–2012 | Low Voltage Circuit Breakers Replacement
- 2008–2012 Emergency Diesel Generator Turbocharger Lube Oil System Modification

Testimony and Regulatory Filings

- 2021-2022 | Expert testimony for Cause No. 19-1614-C26 In the Matter of Litigation between City of Georgetown and Buckthorn Westex, LLC in the 26th District Court of Williamson County, Texas.
- Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. Attachment D to Second Compliance Filing concerning Application of the Minimum Offer Price Rule, June 1, 2020.
- Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), Supplemental Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. Attachment to Re: PJM Interconnection, L.L.C., Docket Nos. EL16-49, EL18-178, ER18-1314 Errata to PJM Compliance Filing re: Hope Creek Nuclear Plant, March 25, 2020.
- Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. Attachment D to Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for an Extended Comment Period of at least 35 Days, March 18, 2020.
- Before the Alberta Utilities Commission, Proceeding No. 23757, Alberta Electric System Operator (AESO) Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, Participated in the hearing as a member of the AESO's witness panel on May 1-3, 2019.
- Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Answering Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C, regarding Cost of New Entry Parameters, Attachment B to Answer of PJM Interconnection, L.L.C. to Protests and Comments, December 17, 2018.

- Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John H. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C." regarding the Cost of New Entry, accompanied by report, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, October 12, 2018.

Languages

- Korean (Fluent)

Exhibit No. 2

2022 CONE Study

PJM CONE 2026/2027 Report

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PREPARED FOR

PJM Interconnection

APRIL 21, 2022

DATE

NOTICE

This report was prepared for PJM Interconnection, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

TABLE OF CONTENTS

Executive Summary

PJM Interconnection, L.L.C (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff. This report presents our estimates of the Cost of New Entry (CONE) for the 2026/2027 commitment period, recommendations regarding the methodology for calculating the net energy and ancillary service revenue offset (E&AS Offset), and our recommendation for the selection of the reference resource. A separate, concurrently-released report presents our review of the VRR curve shape.

Background

The Variable Resource Requirement (VRR) curves set the price at the target reserve margin at approximately Net Cost of New Entry (Net CONE), such that the resource adequacy requirement will be achieved if suppliers enter the market when prices are at least Net CONE. In a downward-sloping curve, slightly lower reliability will be tolerated only when prices exceed Net CONE and some incremental capacity will be procured when the incremental cost is relatively low.

Net CONE is estimated by selecting an appropriate reference resource that economically enters the PJM market, determining its characteristics and its capital costs and ongoing operating and maintenance costs; then estimating a first-year capacity payment needed for entry, given likely trajectories of future total revenues and E&AS offsets.

A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support. Another common misconception is that the Net CONE parameter sets capacity prices. In fact, capacity prices are determined by the intersection of the VRR curves and the supply curves. Long-run market clearing prices depend on the actual prices at which new competitive supply is willing to enter rather than the administrative Net CONE estimates, while the VRR curve determines only the quantity of capacity procured (short-term price impacts of changes in administrative Net CONE may be larger, depending on the elasticity of supply).

Reference Resource

The reference resource should be feasible to build within the three-year period between the Base Residual Auction and the delivery year; economically viable, as indicated by actual merchant entry and competitive costs; and amenable to accurate estimation of its Net CONE.

We recommend shifting the reference resource from the current natural gas-fired combustion turbine (CT) to a natural gas-fired combined cycle (CC) because the CC best meets these criteria in PJM. The CC is clearly economically viable, as it has the largest amount of recent merchant entry and a lower estimated Net CONE than the other candidate resources. CTs continue to be less economic than CCs, consistent with their extremely limited entry in the recent past. Selecting the CT as the reference resource would set the demand curve in a way that would perpetuate excess supply in PJM (although could be considered a way to buy extra reliability insurance for a premium). We considered BESS as a potential source of "clean capacity" for areas with more stringent environmental regulations that could limit the feasibility of developing new natural gas-fired resources. However, its estimated Net CONE is much higher than the CC without there being a clear enough indication at this time that the CC could not be built. We recommend that PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate.

For each resource evaluated, we developed technical specifications of a complete plant reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. The CC specifications are for a 1,182 MW plant with two trains of a single-shift combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two "single-shaft 1x1"s) including 123.9 MW of duct-firing capacity. The CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[1] The CC has a higher-heating value (HHV) average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. CT specifications included a single simple cycle GE 7HA.02 with 367 MW capacity and a 9,189 Btu/kWh full-load average heat rate. BESS specifications are for a 200 MW 4-hour battery with 13% initial oversizing and capacity augmentation planned every 5 years to maintain charge capability and duration.

[1] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

Cost Analysis

For CC and CTs in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. For BESS, we performed a top-down cost analysis based on a less detailed plant design and recent experience estimating costs for developers.

We translate the estimated costs into the net revenues the resource owner would have to earn in its first year to enter the market, assuming a 20-year economic life for the CC and CT and net revenues on average remain constant in nominal terms over that timeframe. We believe these assumptions are reasonable given widespread concern expressed by developers in the stakeholder community that gas-fired generation has limited value beyond the assumed 20-year life in a policy environment that increasingly disfavors greenhouse gas-emitting generation (and even capacity). For the BESS, we assumed a shorter 15-year economic life based on a representative degradation profile and warranty term typical for the selected battery technology.

To estimate the net revenue the reference resource would need to earn to achieve the required return on and return of capital, we estimated the cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.

Table ES-1 below shows the resulting 2026/27 CONE estimates for CCs for each CONE Area. The CONE values are 56% higher (or $180/MW-day ICAP) than PJM's 2022/23 values from the 2018 CONE Study, averaged across all four CONE Areas. Three factors explain this increase:[2]

- Declining Bonus Depreciation**:** Bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $25/MW-Day (ICAP) to CONE.
- Cost Escalation: The costs of materials, equipment, and labor have escalated and will continue to escalate at a faster rate than expected at the time of the last study. These cost increases add $92/MW-Day (ICAP) to CONE, relative to the 2022/23 estimate.

[2] These factors add to more than $180/MW-day (ICAP) due to offsets from a slightly lower cost of capital that reduces CONE by $4/MW-day (ICAP).

- Plant Design Changes: The use of dry-cooling, building a gas-only plant (without dual fuel capability) with firm gas transportation contracts under more constrained environmental permitting regimes (along with smaller increases from 2x1 to double-train 1x1 CCs) adds $66/MW-Day (ICAP).

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

There is considerable uncertainty in the development of the estimated CONE values for the reference resources, particularly regarding volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, and the costs could be greater still if technologies are more constrained by environmental regulations. For BESS, the uncertainty in levelized costs is even greater because of rapidly-changing cost of equipment, currently unresolved applicability of tax credits, and other complications if combined into hybrid plants (and even greater uncertainty with E&AS offsets).

E&AS Methodology

We continue to recommend using a forward-looking E&AS offset, as described in our 2020 testimony and as PJM implemented for its 2022/2023 capacity auction. This approach reflects future market conditions that developers face and avoids distortions from anomalous conditions in a backward-looking approach. We recommend continuing to use the same liquid hubs for natural gas and electricity, and scaling ancillary services prices to energy prices. We recommend that PJM should not include regulation revenues in its estimation of the E&AS offset since the market for regulation is too small to provide substantial additional revenue to capacity entering the PJM market at scale. These recommendations all apply equally to the CT, along with a recommended 10% increase in the estimated day-ahead gas costs to account for having to buy gas in the less liquid intraday market when committed in the real-time market. For BESS, we recommend using the same forward prices along with a virtual dispatch as PJM has been performing with the PLEXOS model.

Application of this forward methodology to CCs leads to indicative E&AS offset values for the CC of $209/MW-day for the RTO, $222 for MAAC, $189 for EMAAC, and $249 for SWMAAC (all denominated in 2026 dollars per UCAP MW-day). This is about $10-30/MW-day greater than the values used for MOPR reviews for the 2022/23 auction, with inflation more than offsetting other factors that tend to decrease the E&AS offset.

Implications for Net CONE and VRR Curve

Elevated Net CONE. With substantially higher CONE and only slightly higher indicative E&AS offsets, indicative CC Net CONE is correspondingly higher, at $307/MW-day for the RTO, $294 for MAAC, $329 for EMAAC, and $257 for SWMAAC (all denominated in 2026 dollars and UCAP MW). This is about $154 higher than CC Net CONE for 2022/23; it is similarly above recent capacity market clearing prices when new CCs entered, and this is consistent with cost escalation, more constrained plant designs, and tax laws; plus likely increased reluctance to invest given a regulatory and market environment that is increasingly favoring clean energy.

Slightly elevated VRR Curve. In spite of significant cost increases, updated CC Net CONE is only $47/MW-day higher than CT Net CONE for 2022/23, since CCs are more economic than CTs. Inefficiently maintaining the CT as the reference resource would increase Net CONE by much more. Thus, switching the reference resource to CCs would moderate the increase and should support procuring reserves closer to target.

Heightened Uncertainty. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we tested robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

I. Introduction

I.A. Background

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which the Variable Resource Requirement (VRR) curve sets the "demand" for capacity. The VRR curve is designed primarily to procure sufficient capacity for maintaining resource adequacy according to traditional standards. The longstanding resource adequacy objectives are to avoid supply shortages in expectations all but once in ten years system-wide (i.e., Loss of Load Expectation or LOLE of 0.1 events/yr), with no more than 0.04 LOLE incremental risk in the Locational Deliverability Areas (LDAs). With probabilistic modeling conducted by PJM, these objectives are translated into Reliability Requirements expressed in terms of megawatts of unforced capacity (MW UCAP).

The VRR curves are centered approximately on a target point corresponding to the Reliability Requirements, at a price given by the estimated long-run marginal cost of capacity, termed the "Net Cost of New Entry (Net CONE)." Rather than a vertical line, the VRR is a curve with nonzero demand above the target to recognize the value of incremental capacity, and with a slope to help mitigate price volatility (as addressed in a separate VRR Curve Study report we are publishing concurrently with this report).

For the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would be willing to enter the market if needed. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would require (in combination with its expected net revenues from the energy and ancillary services markets) to recover its capital and fixed costs, given reasonable expectations about future cost recovery. Thus, Net CONE is given by gross CONE minus the projected Energy and Ancillary Services revenue (E&AS Offset).

Following its tariff, PJM has traditionally estimated Net CONE for a new gas-fired combustion turbine (CT) entering in each of four CONE Areas.[3] Gross CONE values have been determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[4] Shortly before each Base Residual Auction, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction.

PJM also develops Net CONE estimates for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[5] This has less relevance than in past since PJM filed and FERC accepted a revision to MOPR rules that limit its applicability.

I.B. Study Objective and Scope

PJM retained consultants at The Brattle Group and Sargent & Lundy to assist PJM and stakeholders in its quadrennial review. Per the PJM tariff, the scope of the Quadrennial Review is to review the VRR curve and its parameters, including the Cost of New Entry and the E&AS Offset methodology. To that end, a separate, concurrently issued report addresses the shape of the VRR curve. This report:

- Develops CONE estimates for new CT and CC plants and one "clean technology" in each of the four CONE Areas for the 2026/27 Base Residual Auction (BRA) and proposes a process to update these estimates for the following three BRAs;
- Reviews the E&AS offset methodology
- Recommends the most appropriate reference resource whose cost will best indicate the price at which developers would be willing to add capacity.

To estimate CONE for each resource type, we aim to represent the plant configuration, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, not unique sites with unusual characteristics. We estimate costs by specifying the

[3] The four CONE Areas are: CONE Area 1 (EMAAC), CONE Area 2 (SWMAAC), CONE Area 3 (Rest of RTO), and CONE Area 4 (WMAAC). PJM reduced the CONE Areas from five to four following the 2014 triennial review and incorporated Dominion (formerly CONE Area 5) into the Rest of RTO region.

[4] PJM 2017 OATT, Section 5.10 a.

[5] PJM 2017 OATT, Section 5.14 h.

reference resource and site characteristics, conducting a bottom-up analysis of costs, and translating the costs to a first-year CONE.

We provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of CONE, but also inform the range of uncertainty, a key consideration in designing the VRR curve, as discussed in our separate report.

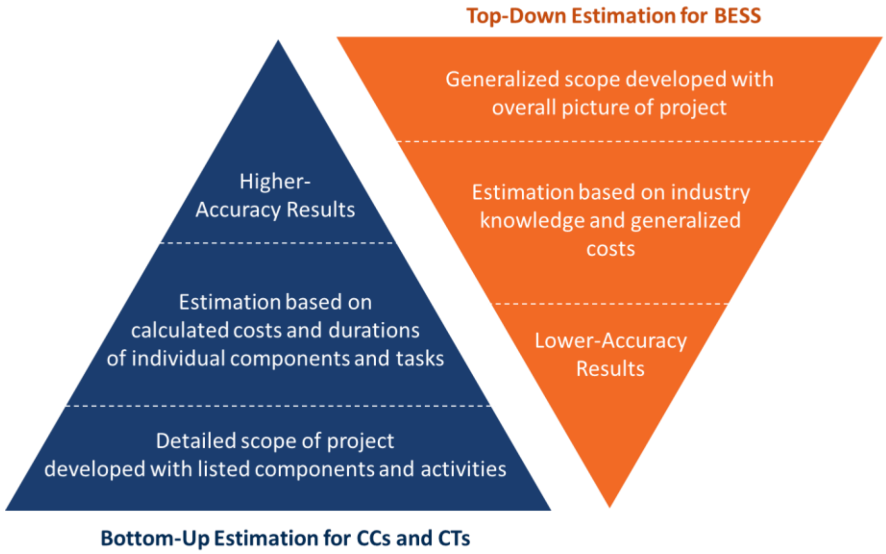
I.C. Analytical Approach

Our starting point is to identify the most appropriate technology to serve as the reference resource for the VRR curve. As discussed in Section II, we identified criteria for selecting the reference resource then evaluated a broad range of resource types against those criteria in an initial screening analysis. This narrowed the choices to a CC, a CT, and BESS, for each of which we analyzed the costs more extensively further—and ultimately recommended using the CC as the reference resource for all locations.

For each of the three identified resources, we estimated CONE for the four CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant characteristics and site characteristics based on: (1) our analysis of the predominant practices of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. Our analysis for selecting plant characteristics for each CONE Area is presented in Section 0 of this report.

We developed comprehensive, bottom-up cost estimates of building and maintaining the reference CC and CT in each of the four CONE Areas. To present a reasonable order-of-magnitude cost estimate for the BESS, we utilized a generalized, top-down approach. Figure 1 describes the attributes of each approach.

FIGURE 1: ATTRIBUTES FOR BOTTOM-UP AND TOP-DOWN ESTIMATION METHODS



Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on developers' long-term market view and how this long-term market view impacts the expected cost recovery path for the plant—specifically whether a plant built today can be expected to earn as much in later years as in earlier years.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Reference Resource Selection

The purpose of selecting a reference resource and developing administrative Net CONE estimates is only to set a VRR curve that aims to procure enough resource adequacy credits. The choice of reference resource does not dictate which resources will enter the market. The administrative Net CONE value does not determine capacity prices; long-run prices depend primarily on the supply curve. Still, as the VRR curve is likely to remain sloped and anchored on our estimate of Net CONE, we aim to estimate Net CONE as accurately as possible, and that starts with a choice of the reference resource.

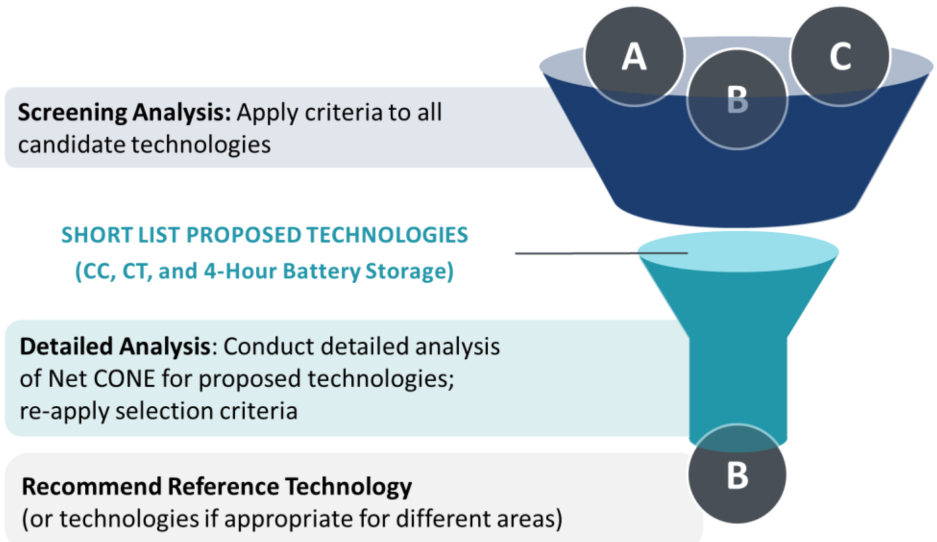
PJM has always used a reference resource, specifically a CT, to estimate Net CONE but asked us to evaluate its continued suitability for representing the cost at which suppliers are willing to bring significant amounts of capacity to PJM. We also considered CCs and a range of other technologies, including BESS as a possible "clean technology" for areas with more stringent environmental regulations. Finally, we also considered the possibility of relying on "empirical Net CONE," i.e. the price at which suppliers have willingly offered new capacity into recent auctions, rather than identifying a specific technology and estimating its net cost for future entry into the market. All possibilities were evaluated against a set of criteria for meeting RPM objectives.

In order to meet RPM reliability objectives with least risk of procuring far above or below target, we recommend switching to a CC as the reference resource. This aligns the VRR curve with observed entry of a technology that is feasible and most economic to build on a merchant basis, and whose Net CONE can be estimated relatively accurately. By contrast, CTs are not being built and are estimated to cost 20% more, on net, for capacity. Other technologies are similarly less economic or otherwise did not meet our selection criteria. Even in areas with more stringent environmental regulations, we did not identify a clear need to adopt a non-emitting reference resource at this time. Finally, empirical Net CONE is a useful benchmark but is not directly suitable because it does not reflect current market conditions affecting the costs of materials, equipment, and labor, nor the regulatory outlook that affects the design of the resources and their future revenue recovery.

II.A. Process for Selecting Reference Resource

We conducted the analysis in several steps, as shown in Figure 2 below. First, we developed criteria for choosing a reference resource; second, we identified a broad range of technologies to evaluate at a high-level against those criteria, resulting in a short list for detailed cost and E&AS analysis; finally, we applied the selection criteria again to select the single most appropriate technology to serve as the reference resource, reflecting the updated net costs of those resources.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS



In consultation with PJM and its stakeholders, we developed the reference resource selection criteria. The foundational objective of the selection criteria was to identify the resource that best supports the RPM's broader objective of procuring enough capacity to meet resource adequacy goals. Given that, we developed three selection criteria.

The first and most basic of these criteria is that the resource has to be feasible to build in the (slightly more than) three-year timeframe between the Base Residual Auction and the Delivery Year, so that high clearing prices in an auction can draw in potential projects when needed/economic.

The second criterion is that the resource must be an economic source of incremental capacity. Otherwise, anchoring the VRR curve on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and lower estimated Net CONE, and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review. The reason for focusing on merchant entrants is partly to ensure that the VRR curve is set high enough to attract merchant entry in the future. It is also to avoid including policy-supported payments (such as renewable energy credits, or RECs) in the E&AS Offset, since such payments are difficult to assess absent broad competitive markets and are limited to the amount of capacity that the policy is intended to achieve. Moreover, such an exercise would suffer from circularity since the necessary level of policy payments needed to support target reasons are in part set by capacity price itself.

The third criterion is that the resource's Net CONE can be estimated accurately. If Net CONE is mis-estimated, the VRR curve will procure more or less capacity than desired. Accurate estimation depends on the certainty of plant designs and their costs and the ability to estimate E&AS offsets using market data. It also depends on the scalability of a standardized resource, not subject to rapid increases in costs as the best sites are exhausted, in which case the cost would depend strongly on penetration. Finally, estimation accuracy also depends on the capacity rating of resources relative to their nameplate. Lower ratings (i.e., low ELCC) magnify the effect of estimation errors on the cost per qualified MW.

Figure 3 summarizes these criteria and sub-criteria for evaluating each candidate resource type.

FIGURE 3: REFERENCE RESOURCE SELECTION CRITIERIA

Feasible to build for the delivery year, given local laws/regulations and technical factors

Economic source of incremental capacity
- Demonstrated by recent merchant entry, not in anomalous situations
- Not having a Net CONE much higher than other candidates
- Likely to remain economic through the end of the review period (2029/30)

Costs, net E&AS revenues, and RA contribution per MW can be assessed accurately
- Evidence of capital and operating costs exists from commercial experience
- Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
- Has stable UCAP/ICAP ratio or ELCC, rather than changing steeply with penetration or fleet composition
- Has high UCAP/ICAP ratio or ELCC, else uncertainties are amplified per kW UCAP
- Not largely dependent on revenues that are difficult to forecast (AS, energy volatility, RECs)

II.B. Evaluation of Candidates against Criteria

The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems (BESS), hybrid photovoltaic (PV)-BESS, utility-scale PV, onshore wind, energy efficiency and demand response, uprates/conversions, and emerging technologies. Screening each of these against the evaluation criteria was straightforward in most cases, as shown in Table 1 below. For example, wind resources currently are not entering as a merchant resource without policy support in PJM, corresponding to its relatively high costs, and its Net CONE would be difficult to assess accurately due to its low ELCC rating that magnifies cost estimation errors. Energy efficiency, DR, and uprates/conversions were eliminated because of highly non-uniform costs across measures and sites, and scalability challenges with any particular type of measure.

TABLE 1: INITIAL REFERENCE RESOURCE SCREENING ANALYSIS

Technology	Feasible to Build for DY	Economic Source of Capacity	Accuracy of Net CONE Estimates	Screening Decision
Gas CC	Yes	Yes	High	Consider as leading candidate
Gas CT	Yes	Unclear (few built, higher Net CONE)	High	Consider for further analysis
Battery Storage	Yes	Unclear (not standalone cleared in RPM)	Medium (falling costs; AS-dependence; ELCC stability?)	Consider for further analysis
Hybrid PV-BESS	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Utility-Scale PV	Yes	Unclear (is any entering as merchant?)	Medium (REC-dependence; ELCC stability?)	Eliminate: Higher Net CONE uncertainty
Wind	Yes	Unclear (is any entering as merchant?)	Low (REC-dependence; low ELCC, stability)	Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR
Energy Efficiency/ DR	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Uprates/ Conversions	Yes	Yes	Low (varies by site)	Eliminate: Inability to accurately estimate Net CONE
Emerging Technologies	No	None	Low	Eliminate: Infeasible to build

Based on stakeholder feedback, we included one non-emitting resource in our CONE and E&AS analysis, selecting BESS due to its lower uncertainty in accurately estimating its Net CONE value compared to utility-scale solar PV and hybrid PV-BESS. Utility-scale solar PV ELCC values are highly uncertain as they decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV investments in PJM depend on RECs, the price of which is uncertain, which increases Net CONE uncertainty; REC prices also depend on capacity prices, creating a circularity that confounds estimating the capacity price at which PVs will enter. Hybrid PV-BESS resources are similarly uncertain as utility-scale solar PV in terms of the ELCC value and dependence on RECs for entry, plus the additional uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

That left CC, CT, and BESS as finalists. Ultimately, CCs best met the selection criteria, as summarized in Table 2 below. They are the most economic and are being built by developers. CTs continue not to be built, consistent with our estimate that their RTO Net CONE is about 20% higher than the CC, as shown in this report. In addition, CC Net CONE can be estimated relatively accurately. The conventional wisdom used to be that CCs are subject to more estimation error in E&AS Offsets, since their E&AS Offsets are larger. We disagree. The benchmark for "accuracy" should be the value that investors anticipate in the market. That benchmark is not directly observable, but there is more market data available to anticipate E&AS Offsets for CCs than CTs. CCs' net E&AS revenues can be fairly accurately approximated assuming 5x16 operation and applying observable futures prices for 5x16 on-peak blocks. No such benchmark is available for CTs that run less frequently when prices spike, so we rely on historical estimates that may not be representative of the future delivery year due to historical anomalies and evolving market conditions. Finally, CTs face less transparent gas procurement costs since they are committed and dispatched day-of.

TABLE 2: BASIS FOR SELECTING THE RECOMMENDED REFERENCE RESOURCE

Technology	Feasible to Build for Delivery Year	Economic Source of Capacity	Accuracy of Net CONE Estimates
Gas CC	**Yes**	**Yes** (significant recent entry; lowest 2026/27 Net CONE)	**Highest**
Gas CT	**Yes** (may be infeasible to build in NJ)	**Unclear** (few recently built; Net CONE 20% higher than CC)	**High** (higher forward E&AS uncertainty due to lack of forward pricing matching CT dispatch)
Battery Storage	**Yes**	**Unclear** (no cleared capacity to date; highest 2026/27 Net CONE among candidates)	**Low** (uncertain future AS revenues; falling costs)

We also considered "empirical Net CONE" based on the clearing price at which new capacity has proven willing to enter in the past several auctions. Historical data do indeed provide a useful reference point for Net CONE, although we rejected using it directly because it is backward-looking at a time when fundamentals are changing profoundly due to cost escalation and clean energy policies.

III. Natural Gas-Fired Combined-Cycle Plants

III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

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6 For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

7 The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

CONE Area	Elevation	Max. Summer Temperature	Relative Humidity
	(ft)	*(°F)*	*(%RH)*
1 EMAAC	330	92.2	55.3
2 SWMAAC	150	96.2	44.2
3 Rest of RTO	990	89.9	49.7
4 WMAAC	1,200	91.4	48.9

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

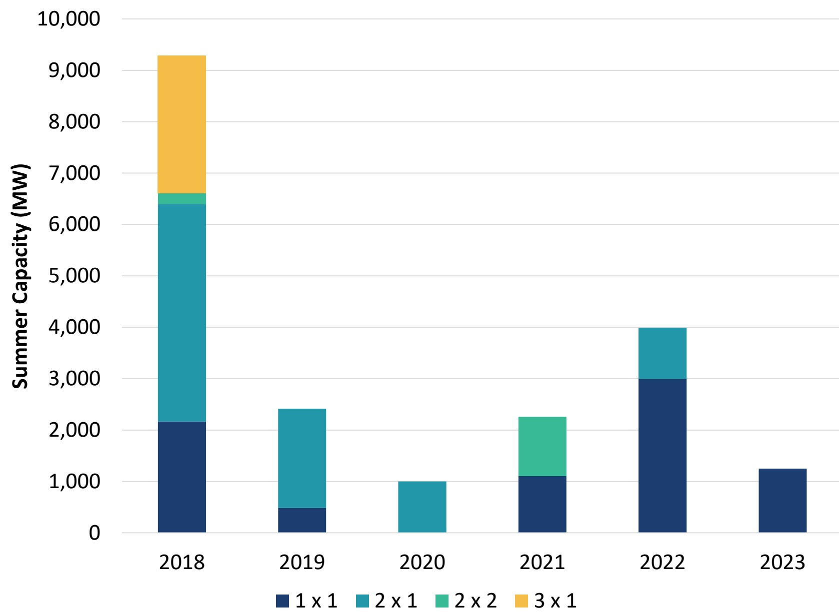
Plant Characteristic	Specification
Turbine Model	GE 7HA.02 (CT), STF-A650 (ST)
Configuration	Double Train 1 x 1
Cooling System	Dry Air-Cooled Condenser
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
without Duct Firing	1043 / 1047 / 1020 / 1011*
with Duct Firing	1171 / 1174 / 1144 / 1133*
Net Heat Rate (HHV in Btu/kWh)	
without Duct Firing	6365 / 6383 / 6359 / 6368*
with Duct Firing	6602 / 6619 / 6593 / 6601*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018



Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Number of Trains	2018 *(MW)*	2019 *(MW)*	2020 *(MW)*	2021 *(MW)*	2022 *(MW)*	2023 *(MW)*	Total Capacity *(MW)*	Capacity Share *(%)*
1	1,184	485	0	1,104	0	0	2,774	35%
2	980	0	0	0	1,116	1,250	3,346	42%
3	0	0	0	0	1,875	0	1,875	23%
All CC Plants	**2,164**	**485**	**0**	**1,104**	**2,991**	**1,250**	**7,994**	**100%**

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

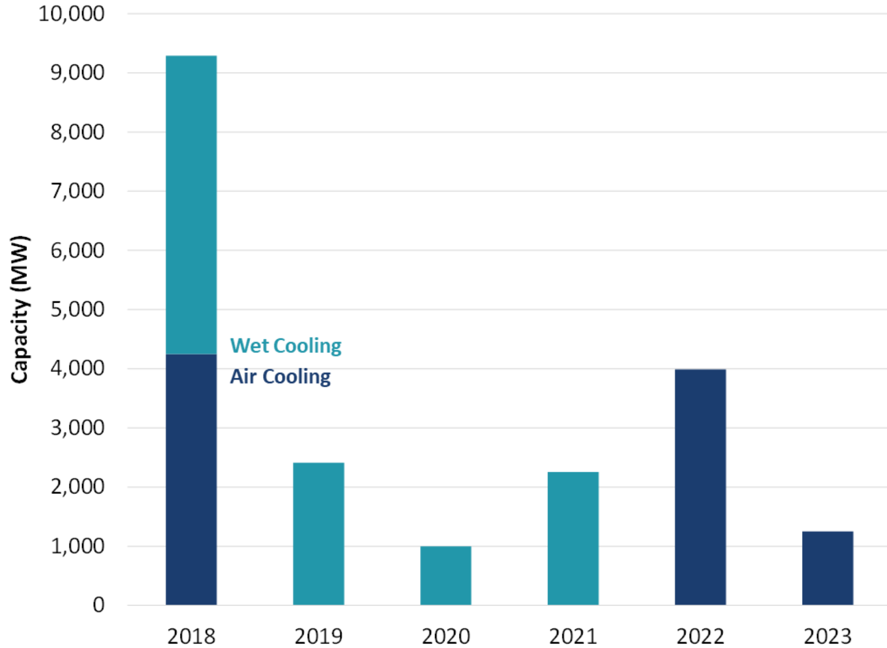
III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize “wet” cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

8 PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

FIGURE 5: COOLING SYSTEM FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

III.A.3. Emissions Controls

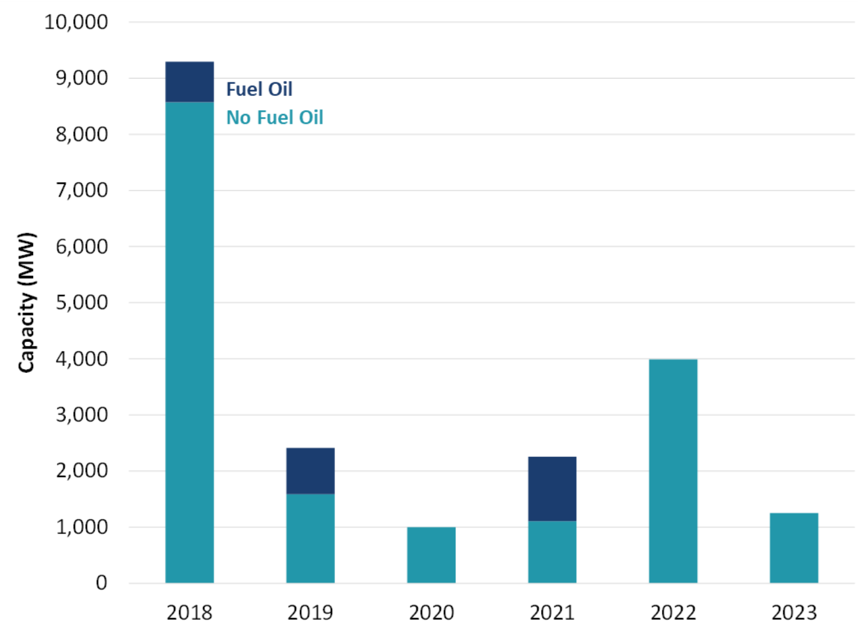
The reference CC is assumed to utilize selective catalytic reduction (SCR) systems as a nitrogen oxide (NOx) emissions control technology and CO catalyst systems as a carbon monoxide (CO) emissions control technology. The SCR system and CO catalyst adds an incremental cost of $72 million (in 2021 dollars) to the capital costs. A more detailed discussion of emissions controls can be found in the 2018 PJM CONE study.

III.A.4. Fuel Supply

Natural gas-fired plants can be designed to operate solely on gas or with “dual-fuel” capability to burn either gas or diesel fuel oil. Dual-fuel plants can switch to oil when gas becomes unavailable or prohibitively costly due to pipelines becoming fully utilized and congested. Plants without dual-fuel capability can ensure access to their fuel supply through firm transportation contracts, although such contracts cost more than dual-fuel capability in most locations.[9]

Developers have moved away from installing dual-fuel capability on new CCs. Figure 6 below shows that only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel since 2018; data from PJM confirms that almost all are instead firming their availability with firm gas transportation contracts.

FIGURE 6: DUAL-FUEL CAPABILITY FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018



Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted).

Instead, we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2016/2017 BRA obtain firm transportation service to ensure adequate fuel supply.[10] Based on these trends, we updated our assumption from the

[9] Eastern Interconnection Planning Collaborative, "Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives," accessed September, 2017, http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

[10] PJM provided the fuel supply arrangements for 20,848 MW of new gas plants that first cleared the capacity market in the 2016/2017 BRA to the 2020/2021 BRA, including firm transportation, dual fuel capability, and installing gas laterals to multiple pipelines.

2018 PJM CONE study for the CC reference resource to obtain firm gas supply across all CONE areas.[11] The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs in the following section.

III.B. Capital Costs

Plant capital costs are costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2021 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix A.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost for an online date of June 1, 2026 by escalating the 2021 costs using escalation rates provided by Sargent & Lundy. The 2026 "installed cost" is the present value of the construction period cash flows as of the end of the construction period, using the monthly drawdown schedule and the cost of capital for the project.

Based on the technical specifications for the reference CC described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 6 below. The maximum variation between overnight capital costs between CONE areas is $100/kW, similar to the $94/kW from the 2018 PJM CONE study. The methodology and assumptions for developing the capital cost line items are described further below.

[11] We recommended in the 2018 PJM CONE study dual-fuel capabilities in all CONE Areas except SWMAAC. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

TABLE 6: PLANT CAPITAL COSTS FOR CC REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1171 MW*	*1174 MW*	*1144 MW*	*1133 MW*
Owner Furnished Equipment				
Gas Turbines	$155.3	$155.3	$155.3	$155.3
HRSG / SCR	$80.7	$80.7	$80.7	$80.7
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$320.7**	**$320.7**	**$320.7**	**$320.7**
EPC Costs				
Equipment				
Other Equipment	$86.3	$86.3	$86.3	$86.3
Construction Labor	$365.5	$283.3	$297.1	$330.5
Other Labor	$75.5	$69.0	$70.1	$72.7
Materials	$75.5	$75.5	$75.5	$75.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$98.5	$89.6	$91.1	$94.7
EPC Contingency	$108.4	$98.6	$100.2	$104.2
Total EPC Costs	**$871.4**	**$763.9**	**$782.0**	**$825.6**
Non-EPC Costs				
Project Development	$59.6	$54.2	$55.1	$57.3
Mobilization and Start-Up	$11.9	$10.8	$11.0	$11.5
Net Start-Up Fuel Costs	-$13.9	-$14.0	-$9.8	-$13.5
Electrical Interconnection	$25.3	$25.4	$24.7	$24.5
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$2.2	$1.8	$1.0	$1.8
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$6.0	$5.4	$5.5	$5.7
Owner's Contingency	$10.0	$9.4	$9.7	$9.7
Emission Reduction Credit	$2.3	$2.3	$2.3	$2.3
Financing Fees	$29.2	$26.7	$27.2	$28.1
Total Non-EPC Costs	**$166.4**	**$155.8**	**$160.6**	**$161.3**
Total Capital Costs	**$1,358.5**	**$1,240.5**	**$1,263.3**	**$1,307.6**
Overnight Capital Costs ($million)	**$1,359**	**$1,240**	**$1,263**	**$1,308**
Overnight Capital Costs ($/kW)	**$1,160**	**$1,057**	**$1,104**	**$1,154**
Installed Cost ($/kW)	**$1,255**	**$1,144**	**$1,195**	**$1,248**

III.B.1. EPC Capital Costs

III.B.1.i. Project Developer and Contract Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

III.B.1.ii. **Equipment and Materials**

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines. The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. We assume all purchases for plant equipment are exempt from sales tax.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

III.B.1.iii. **Labor**

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Similar to the 2018 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region in 2021, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix A.

III.B.1.iv. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to the Owner Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Capital cost estimates include an EPC contractor fee of 10% of total EPC and OFE costs for CC facilities based on S&L's proprietary project cost database.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, including the contractor fee. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.7% to 9.8% of the pre-contingency overnight capital costs.

III.B.2. Non-EPC Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

III.B.2.i. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.ii. Net Startup Fuel Costs

Before commencing full commercial operations, the new CC plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix A.

III.B.2.iii. Emission Reduction Credits

Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as attainment. ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are determined based on the annual NOx and volatile organic compounds (VOC) emissions of the facility and offset ratio which is dependent on the specific plant location. Similar to our assumption from the 2018 PJM CONE study, we assumed a cost of $5,000/ton for all CONE Areas and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2021 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

III.B.2.iv. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. We assume the gas interconnection will require a metering station and a five-mile lateral connection, similar to the 2018 PJM CONE Study. From the data summarized in Appendix A, we estimate that gas interconnection costs will be $29.5 million (in 2021 dollars) based on $5.1 million/mile and $4.0 million for a metering station. Similar to the 2011, 2014, and 2018 PJM CONE studies, we found no relationship between pipeline width and per-mile costs in the project cost data.

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using recent project data provided by PJM with the online service year between 2018 and 2021, we selected 17 projects (3,700 MW of total capacity) that are representative of interconnection costs for a new gas CCs and calculated a capacity-weighted average electrical interconnection cost of $18.9/kW (in 2021 dollars) for these projects, 5% lower than the 2018 PJM CONE Study. The estimated electric interconnection costs are between $21.4 and $22.2 million for CCs (in 2021 dollars). Appendix A presents additional details on the calculation of electric interconnection costs.

III.B.2.v. **Land**

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We assume that 60 acres of land are required for the CC. Table 7 shows the resulting costs (see Appendix A for more detail).

TABLE 7: COST OF LAND PURCHASED FOR REFERENCE CC

CONE Area	Land Price *($/acre)*	Plot Size Gas CC *(acres)*	Cost Gas CC *($m)*
1 EMAAC	$36,600	60	$2.20
2 SWMAAC	$29,500	60	$1.77
3 Rest of RTO	$16,400	60	$0.98
4 WMAAC	$30,600	60	$1.84

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

III.B.2.vi. **Non-Fuel Inventories**

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel inventories are 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

III.B.2.vii. **Owner's Contingency**

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

[12] The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

2026.[13] The real escalation rate for each cost category was then added to the assumed inflation rate to determine the nominal escalation rates, as shown in Table 8.

TABLE 8: CC AND CT CAPITAL COST ESCALATION RATES (% PER YEAR)

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.00%	2.91%
Labor	1.60%	4.51%

Sources and notes: Escalation rates on equipment and materials costs are derived from the BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from the current overnight costs to the month they would be incurred using the monthly capital drawdown schedule developed by S&L for an online date in June 2026.

We escalated several cost items in a different manner:

- Land: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2026 online date, the land is thus assumed to be purchased in late 2022 such that current estimates are escalated 1 year using the long-term inflation rate of 2.9%.
- Net Start-Up Fuel and Fuel Inventories: no escalation was needed as we forecasted fuel and electricity prices in 2026 dollars.
- Electric and Gas Interconnection: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior to completion, consistent with the 2018 PJM CONE Study; the interconnection costs have been escalated specifically to these months.
- Emission Reduction Credits: escalated to the online start date of June 2026 using the long-term inflation rate of 2.91%.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2026 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate

[13] The near-final CONE results presented on March 25, 2022 assumed an inflation rate of 2.0%.

the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

III.C. Operations and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including contracted services, property tax, insurance, labor, maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated *variable* O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations.

III.C.1. Summary of O&M Costs

Table 9 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2026.

TABLE 9: O&M COSTS FOR CC REFERENCE RESOURCE

	CONE Area			
O&M Costs	**1** **EMAAC** *1171 MW*	**2** **SWMAAC** *1174 MW*	**3** **Rest of RTO** *1144 MW*	**4** **WMAAC** *1133 MW*
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.8	$0.8	$0.8	$0.8
Labor	$5.2	$5.6	$4.0	$4.1
Maintenance and Minor Repairs	$6.6	$6.7	$6.0	$6.1
Administrative and General	$1.4	$1.4	$1.2	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.2
Property Taxes	$3.0	$16.4	$9.5	$2.9
Insurance	$8.2	$7.4	$7.6	$7.8
Firm Gas Contract	$10.0	$12.4	$16.4	$14.5
Working Capital	$0.2	$0.1	$0.1	$0.1
Total Fixed O&M (2026$ million)	**$36.8**	**$52.6**	**$46.8**	**$38.8**
Levelized Fixed O&M (2026$/MW-yr)	**$31,500**	**$44,900**	**$40,900**	**$34,200**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	0.76	0.76	0.77	0.77
Total Variable O&M (2026$/MWh)	**2.08**	**2.07**	**2.12**	**2.14**

III.C.2. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

III.C.2.i. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, we include the monthly payments specified in the LTSA as fixed O&M costs and the larger costs associated with run-time and starts as variable O&M.

III.C.2.ii. Insurance and Asset Management Costs

We estimate insurance cost of 0.6% of the overnight capital cost per year, from the 2018 PJM CONE study based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of natural gas-fired plants in operation.

III.C.2.iii. Property Tax

We maintained our bottom-up approach for estimating property and personal taxes from the 2018 PJM CONE study. We researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states.[14] The tax rates assumed for each CONE Area are summarized in Table 10 with additional details in Appendix A.

[14] See the 2018 PJM CONE study for a detailed discussion on our bottom up approach.

TABLE 10: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

	Real Property Tax	Personal Property Tax	
	Effective Tax Rate	Effective Tax Rate	Depreciation
	(%)	*(%)*	*(%/yr)*
1 EMAAC			
New Jersey	3.8%	n/a	n/a
2 SWMAAC			
Maryland	1.1%	1.3%	3.30%
3 RTO			
Ohio	1.9%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	2.7%	n/a	n/a
4 WMAAC			
Pennsylvania	3.8%	n/a	n/a

Sources and notes: See Appendix A for additional detail on inputs and sources.

We assume that assessed value of real property will escalate in future years with inflation. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years.

III.C.2.iv. **Working Capital**

Based on our approach in the 2018 PJM CONE study, we estimate the costs of maintaining the working capital requirement assuming that the working capital requirement is approximately 0.5% of overnight costs and a borrowing rate for short-term debt of 2.1%.[15]

III.C.2.v. **Firm Transportation Service Contracts**

We maintained our approach for estimating firm transportation service contracts from the 2018 PJM CONE study for the SWMAAC CONE Area for the reference CC. However, we utilized the reservation and usage charges for pipelines servicing EMAAC, Rest of RTO, and WMAAC under FT-1 rate schedules. Table 11 summarizes the pipelines we assumed for each CONE area and the representative firm gas capacity costs. We assume the reference CC commit to procuring firm gas transportation on an annual basis.

15 15-day average 3-month bond yield as of January 31, 2022, BFV USD Composite (BB), from Bloomberg.

TABLE 11: CONE AREA PIPLEINES AND FIRM GAS CAPACITY COSTS

	CONE Area	Pipelines	Representative Firm Gas Capacity Cost *(2026$ per Dth/d per Mth)*
1	**EMAAC**	Transco Zone 6 (non-NY), Transco Zone 6 (NY)	$4.50
2	**SWMAAC**	Dominion Cove Point	$5.56
3	**Rest of RTO**	Chicago, Columbia-Appalachia TCO, Dominion South, Michcon, Transco Zone 5	$7.54
4	**WMAAC**	Tennessee 500L, TETCO M3	$6.73

To estimate the costs of acquiring firm transportation service for SWMAAC we escalated the Cost of Firm Gas Capacity per Month of $4.96 (2022$ per Dth/d) from the 2018 PJM CONE study by 2.9% annually to 2026. For the EMAAC, Rest of RTO, and WMAAC CONE Areas, we combined the reservation and usage rates, resulting in a tariff rate for each pipeline. Then the pipeline tariff rates are averaged and escalated by 2.9% annually to 2026 by CONE area to calculate the representative firm gas capacity. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix A.

III.C.3. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. As discussed above, we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.

III.C.4. Escalation to 2026 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 8) have been used to escalate the O&M costs. The assumed real escalation rate for O&M line items that are primarily labor-based is 1.6% per year, while those for other O&M costs remain constant in real terms.

III.D. Financial Assumptions

III.D.1. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[16] Consistent with our approach in previous CONE studies, we developed our recommended cost of capital by an independent estimation of the ATWACC for publicly-traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from recent merger and acquisition transactions.[17] Based on our empirical analysis as of March 31, 2022, we recommend 8.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2026 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, cost of debt 4.7%, a combined federal and state tax rate of 27.7%, and return on equity (ROE) of 13.6%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and ROE do not significantly affect the CONE calculation as long as they amount to the empirically-based 8.0% ATWACC.[19] This is because the CONE value is determined by the 8.0% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

As a point of reference, we compare our current ATWACC recommendation to recommendations in our prior PJM CONE studies in Figure 7. The red circles (35% federal tax rate for 2011 and

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16 The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

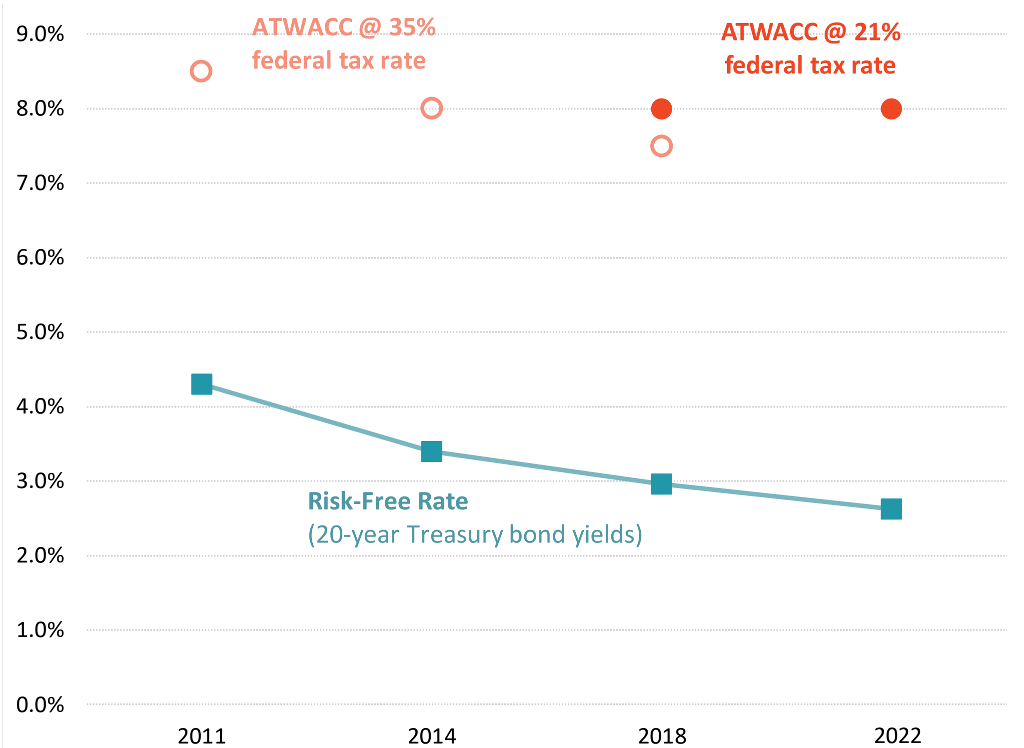
17 Supplementing our ATWACC analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours.

18 4.7% × 55% × (1 – 27.7%) + 13.6% × 45% = 8.0%. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes (= 8.5% + (1 – 8.5%) × 21%). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

19 Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

2014) and dots (21% tax rate for 2018 and 2022) represent the recommended ATWACCs, and the line is the prevailing risk-free rate (20-year Treasury rate).

FIGURE 7: COMPARISON OF BRATTLE ATWACC RECOMMENDATIONS FOR PJM



Sources: 2011, 2014, and 2018 values based on previous PJM CONE studies.

Over the last decade, our recommended ATWACC of merchant generation was 8.5% in 2011, then dropped and stayed at 8% between 2014 and 2022. These changes are driven by changes in both business risks of the industry, and market risks such as the risk-free rate and corporate income tax rates.

- We lowered the ATWACC from 8.5% to 8% in 2014 because the 20-year Treasury rate dropped from 4.3% in 2011 to 3.4% in 2014.
- The 20-year Treasury rate dropped further in 2018 to 3.0%. However, we kept our ATWACC recommendation at 8%, because the reduction in federal corporate income tax rate, from 35% to 21% starting from 2018, increases the ATWACC.
- The 20-year Treasury rate dropped again in 2022 to 2.6% as of March 2022. However, the top of the ATWACC range from the sample (the business risk of the merchant generation industry) and the additional reference points approximates 8.0% (Figure 8).

In Table 12, we compare our current recommended costs of capital components to those in our prior PJM CONE studies. The changes in the return of equity (ROE) are based on a number of factors: our recommended ATWACC, the federal-state combined tax rate, cost of debt, and the debt/equity ratios.

TABLE 12: COMPARISON OF COST OF CAPITAL RECOMMENDATIONS

Study Year	Tax Rate	Return on Equity	Equity Ratio	Cost of Debt	Debt Ratio	ATWACC
2011	40.5%	12.5%	50%	7.5%	50%	8.5%
2014	40.5%	13.8%	40%	7.0%	60%	8.0%
2018	27.7%	13.0%	45%	5.5%	55%	8.0%
2022	27.7%	**13.6%**	45%	**4.7%**	55%	8.0%

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for U.S. IPPs. Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[20] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

ATWACC for Publicly Traded Companies as of March 31, 2022: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 13 and charted with sensitivities in Figure 8. Base-case estimates are derived from three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 6.3% for AES to 7.6% for NRG. Additional details about the sample and key inputs are discussed next.

[20] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

TABLE 13: BASE-CASE ATWACC - 2022

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$15,862	$17,754	1.10	10.8%	41%	4.3%	6.3%
NRG Energy Inc	BB+	$9,179	$8,202	1.15	11.2%	53%	4.9%	7.6%
Vistra Corp	BB	$10,117	$10,515	1.10	10.8%	47%	5.2%	7.1%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 3/31/2022, millions USD.
[4]: Value Line.
[5]: RFR (2.62%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

Sample: Our sample consists of three companies: NRG, Vistra, and AES. Since 2018, there are no longer any pure-play merchant generation companies in the US. In 2018, Calpine was taken private by a consortium of private investors, and Dynegy was acquired by Vistra. The new Vistra includes both electricity generation and retail electricity supply. In addition, NRG expanded into competitive retail electricity supply. NRG and Vistra do not currently report their operating segments along the generation and retail supply lines of business. Their business mixes in terms of operating profits in 2019 are shown in Table 14.[21] Our sample also includes AES, a diversified global energy company holding assets in both utilities and the construction and generation of electricity. However, its annual financials only disclose its business segments by geography, not by line of business.[22]

TABLE 14: BUSINESS MIX OF NRG AND VISTRA IN 2019

Company [1]	Retail [2]	Generation [3]
NRG	38%	62%
Vistra	8%	92%

[21] NRG changed its segment reporting in 2020 such that the split between power generation and retail is not available.

[22] AES discloses its annual financials for each of its strategic business units: US and Utilities (which covers the United States, Puerto Rico and El Salvador); South America (which covers Chile, Colombia, Argentina and Brazil); MCAC (which covers Mexico, Central America and the Caribbean); and Eurasia (which covers Europe and Asia). Source: The AES Corporation. (December 31, 2019). Form 10-K. https://s26.q4cdn.com/697131027/files/doc_financials/2019/q4/2019-Form-10-K-FINAL.pdf.

Cost of Equity: We estimate the return on equity (ROE) of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 13, the resulting return on equity ranges from 10.8-11.2% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- We estimated the expected risk premium of the market to be 7.46% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[23]
- In Table 13, we use a risk-free rate of 2.62%, a 15-day average of 20-year U.S. treasuries as of March 31, 2022, as the base case. In addition to our base analysis under current market conditions, we also consider the use of forecasted risk-free rates applicable five years from now to estimate the offer of a new merchant entrant that starts operating in 2026. Blue Chip Economic Indicators forecasts a 3.0% yield for 10-year Treasury yields between 2023 and 2026.[24] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.5%, we estimate the 20-year risk-free rate to be 3.5% and use this as a sensitivity analysis, as shown in Figure 8 below.
- We use betas (column [4] in Table 13) reported by Value Line.[25] They are calculated using 2-year weekly returns.

Cost of Debt: In our previous analyses, we estimated the cost of debt (COD) of the sample companies by the average bond yields corresponding to the unsecured senior credit ratings for each company (issuer ratings).[26] The rating-based average yields, based on a sample of similarly-

[23] Kroll Cost of Capital Navigator 2021, as of February 2022 (arithmetic average of excess market returns over 20-year risk-free rate from 1926-2021).

[24] Blue Chip Economic Indicators (March 2022), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers.

[25] The 3-year period is chosen over the standard 5-year period to limit the period under the new tax law, which went into effect in 2018, and also to limit the period to be post integration of the 2017 Dynegy / Vistra merger and the spinoff of NRG Yield in 2018.

[26] In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

rated long-term (10 plus years) corporate bonds, are generally preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[27]

TABLE 15: COST OF DEBT

Company	S&P Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
AES Corp	BBB-	2.5%	4.3%
NRG Energy Inc	BB+	2.8%	4.9%
Vistra Corp	BB	3.1%	5.2%

However, company-specific CODs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate. This is the case for the merchant generation corporations: the average yields for the BBB-, BB+, and BB rated corporate bonds are barely higher than the current risk-free rate and lower than the Blue Chip forecast for the risk-free rate in 2022 and 2023. In contrast, U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the base-case estimation in Table 13, we use the company-specific bond yield, but in the sensitivity analysis (Figure 8 below) we also use rating-based cost of debt.

Debt/Equity Ratio: We estimate the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg. They are reported in Table 13 above.

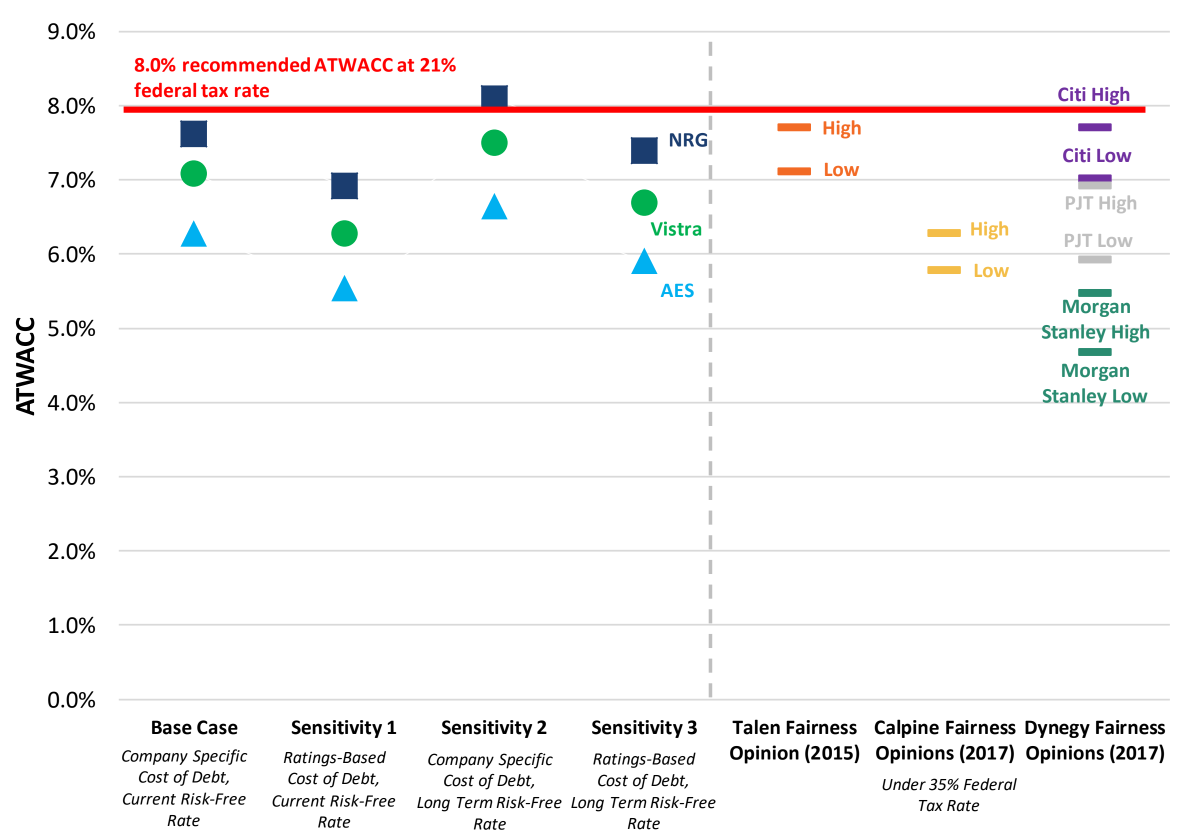
ATWACC Sensitivities and Cost of Capital Benchmarks from Recent Fairness Opinions:
Figure 8 reports the ATWACC for the sample under alternative assumptions for the COD and risk-free rate, along with the discount rates used in fairness opinions (discussed below) as additional reference points:

- *Baseline Case* uses the inputs and results shown in Table 13 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted long-term risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted long-term risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

[27] These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. By construction, these factors tend to be averaged out in the ratings-based average CODs.

For the Base Case and each sensitivity, the colored marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs range from 5.5% (AES) to 6.9% (NRG). Under the other two scenarios when the forecasted risk-free rate is used, the upper ends of the ATWACC approach 8.1% (Sensitivity 2) and 7.4% (Sensitivity 3).

FIGURE 8: SUMMARY OF BASE CASE AND ALTERNATIVE CASES



Additional cost of capital reference points shown on the right side of Figure 8 above come from publicly-available discount rates used by financial advisors and analysts in valuations associated with mergers and divestitures. While there are no details provided on how these ranges were developed, these values still provide useful reference points for estimating the cost of capital. As in our 2018 analysis, we rely on three transactions with publicly-disclosed discount rates, and adjust them for the changes in the risk-free rates between the as of dates of the fairness opinions and March 31, 2022. These three transactions are

- *Acquisition of Talen Energy by Riverstone Holdings*: the disclosed range of discount rate is 6.7% to 7.3%, released in June 2016.[28] Between the fairness opinion date (March 31, 2016)

[28] Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016.

and March 31, 2022, the risk-free rate increased about 0.4%. As a result, the range of 7.1% to 7.7% is shown in Figure 8.

- *Acquisition of Calpine by Energy Capital Partners*: the range of discount rate range disclosed in the June 2017 fairness opinion is 5.75% to 6.25%;[29] this is also the range shown in Figure 8, as the risk-free rates between June 2017 and March 31, 2022 are almost the same;
- *Acquisition of Dynegy by Vistra*: each of the three financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) involved in that transaction used a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citi.[30] This rather wide range of discount rates (4.7% to 7.7%) reflects the uncertainty in cost of capital estimates for the U.S. merchant generation industry. Because the risk-free rates between the fairness opinion dates and March 31, 2022 are almost the same, the originally disclosed range is shown in Figure 8.

We should note that all these acquisitions were announced before the 2018 tax law change, so their discount rates were based on the 35% federal corporate income tax rate. All else equal, the discount rate would be higher under a lower federal income tax rate. In other words, the ranges shown in Figure 8 under-estimates the ATWACC from the transactions under the current 21% tax rate.

ATWACC for Merchant Generators in PJM Markets and the Recommended Components: The appropriate ATWACC for the CONE study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As a pure merchant project in PJM, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts in place.[31] As we have done in previous studies, we make an upward adjustment toward the upper end of the range from the comparable company results to reflect the relatively higher risk of pure merchant operations. Based on the set of reference points shown in Figure 8 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation

[29] Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

[30] Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 25, 2018.

[31] This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

companies, we believe that an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[32]

III.D.2. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal tax rates of 21%. The state tax rates assumed for each CONE Area are shown in Table 16.

TABLE 16: STATE CORPORATE INCOME TAX RATES

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	11.50%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%

Sources and notes: State tax rates retrieved from www.taxfoundation.org. Machinery and equipment for electricity generation are exempt from state sales taxes.

We calculated depreciation for the 2026/27 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2027 can apply 20% bonus depreciation in the first year of service, which decreases CC CONE on average by $10/MW-day relative to no bonus depreciation. The bonus depreciation phases out completely by the following year. Similar to the 2018 PJM CONE study, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for the reference CC to the remaining depreciable costs (*i.e.*, 20% bonus depreciation, 80% MACRS in 2026/27).[33]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of

[32] The weighted average cost of capital (WACC) without considering the tax advantage of debt payments is 8.0%. We report this value because it is comparable to values reported in other recently released CONE studies in ISO-NE and NYISO.

[33] Internal Revenue Service (2021), *Publication 946, How to Depreciate Property,* March 3, 2022. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 55% debt and 4.7% COD.

III.E. Economic Life and Levelization Approach

Translating investment costs into annualized costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life, such that the investor recovers capital and annual fixed costs.

For economic life, we recommend continuing the prior assumption of a 20-year economic life. Although new natural gas-fired plants can physically operate for 30 years or longer, developers in the stakeholder community expressed doubt in any value beyond 20 years in the current and projected policy environment. The policy environment is increasingly disfavoring generation resources that emit greenhouse gases. For example, Illinois and New Jersey have passed legislation or are considering regulations to limit the operation of natural gas-fired plants.[34]

We continue to assume "level-nominal" cost recovery with net revenues constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms), based on our prior analysis of the drivers of long-term cost recovery and updated analysis of the long-term trends in gas turbine costs. Clearly, assuming such a steady stream of revenues then terminating them after an assumed 20-year life is a simplification. Our concurrent VRR Report tests the robustness of the recommended VRR curve to an uncertainty range that encompasses different assumptions on cost recovery.

[34] In Illinois, the 2021 Climate and Equitable Jobs Act (CEJA) phases out of privately-owned gas generation by 2045. While the CEJA does not limit the ability of new CCs to enter, alternative ownership structures may be required with public entities to maintain operation over a 20-year economic life. In New Jersey, the Department of Environmental Protection proposed rules in 2021 that would limit CO_2 emissions for new gas generation units to below 860 lbs CO_2/MWh starting in 2025. Despite this proposed rule, the reference CC will be able to meet the emissions requirements.

III.F. CONE Results and Comparisons

III.F.1. Summary of CONE Estimates

The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 17 summarizes our plant capital costs, annual fixed costs, and levelized CONE estimates for the CC reference plants for the 2026/27 delivery year. The level-nominal CONE estimates range from $506/MW-day in WMAAC to $490/MW-day in SWMAAC.

TABLE 17: ESTIMATED CONE FOR CC PLANTS IN 2026/27

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

Sources and notes: CONE values expressed in 2026 dollars and ICAP terms.

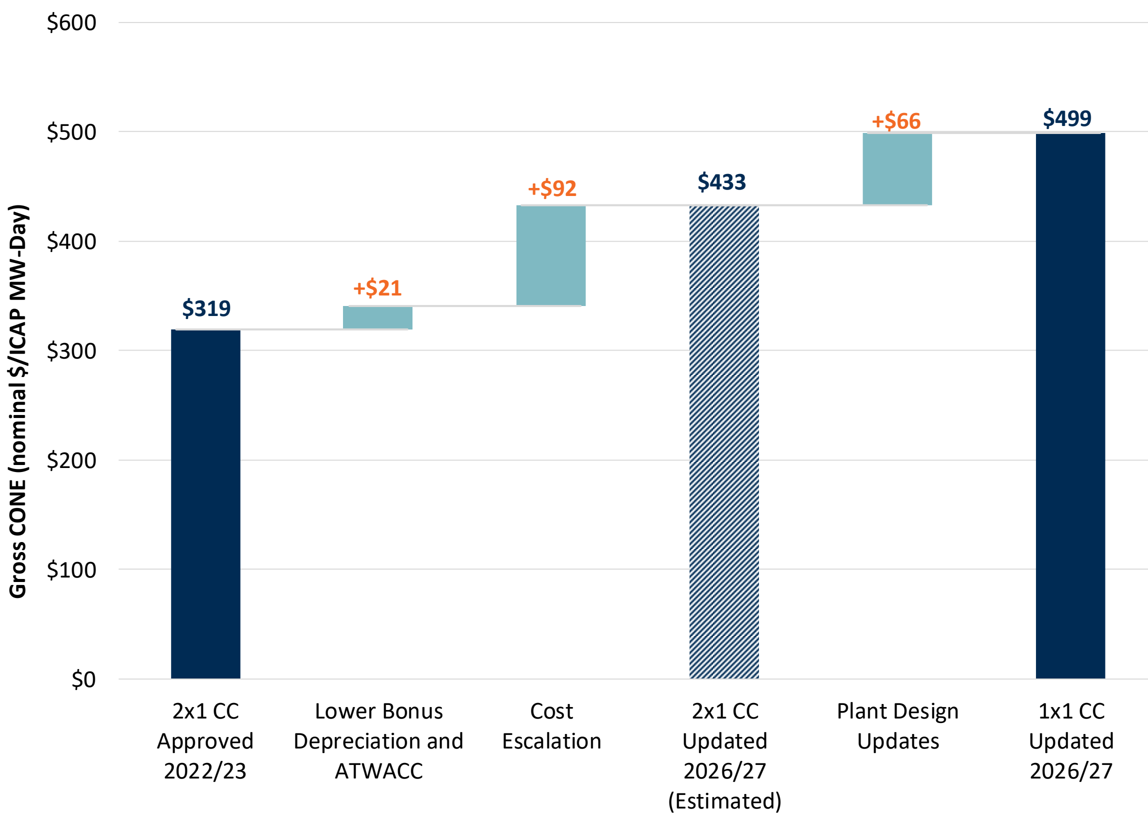
The CC CONE estimates vary slightly by CONE Area, primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

III.F.2. Comparison to Prior CONE Estimates

The 2026/27 CC CONE estimates are considerably higher than the values derived from the 2018 Study that were used (as MOPR parameters) in PJM's Base Residual Auction for the 2022/23

Delivery Year as shown in Figure 9. To explain those increases in terms of individual drivers, we sequentially estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, plant design updates.

FIGURE 9: DRIVERS OF HIGHER CC 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The temporary 100% bonus depreciation included in the 2022/23 CONE value decreases to 20% by 2026, increasing CONE by $25/MW-Day (ICAP).[35] The ATWACC decreased from 8.2% in the prior CONE value to 8.0% currently, decreasing CONE by $4/MW-Day (ICAP), for a net effect of $21/MW-Day (ICAP).
- Cost Escalation: Since the development of the 2022/23 CONE value in our 2018 Study (based on overnight costs of a plant built in 2017), the costs of materials, equipment, and labor costs have escalated along with generalized inflation at a faster rate than expected. For example, from December 2017 to December 2021, material costs increased by 36% compared to

[35] 115th United State Congress, "Tax Cuts and Jobs Act," Signed into law December 22, 2017

expectations of only 10%.[36] With that unexpected escalation over that time period, plus projected escalation to a 2026 installation, total cost escalation to 2026/27 adds $92/MW-Day (ICAP) to the 2x1 CC 2022/23 CONE value.

- Plant Design Updates: The use of dry-cooling ACCs, firm gas transportation contracts (and to a small degree the switch from a 2x2 CC to a double-train 1x1 CCs) as discussed in Section III.A above, adds $66/MW-Day (ICAP) to the 2x1 CC Updated 2026/27 (Estimated) CONE.

III.G. Annual CONE Updates

The PJM tariff specifies that prior to each auction PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review. The updates will account for changes in plant capital costs based on a composite of Department of Commerce's Bureau of Labor Statistic indices for labor, turbines, and materials.

We recommend that PJM continue to update the CONE value prior to each auction using this approach with slight adjustments to the index weightings based on the updated capital cost estimates. As shown in Table 18 below, we recommend that PJM re-weight the components to account for the increasing portion of total plant costs that are from the costs of labor. For the CC, PJM should calculate the composite index based on 40% labor, 45% materials, and 15% turbine. For the CT, PJM should calculate the composite index based on 30% labor, 45% materials, and 25% turbine.

TABLE 18: CONE ANNUAL UPDATE COMPOSITE INDEX

	Combustion Turbine			**Combined Cycle**		
Component	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index	PJM Tariff Composite Index	CONE Study Capital Cost Weightings	Recommended Composite Index
Labor	20%	30%	30%	25%	43%	40%
Materials	50%	45%	45%	60%	45%	45%
Turbine	30%	25%	25%	15%	12%	15%

PJM will need to account for bonus depreciation declining from 20% for the 2026/2027 BRA to 0% in the 2027/2028 BRA and subsequent auctions. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 1.7% and the CC CONE by 2.1% due to the decreasing depreciation tax shield. We recommend just for the 2027/2028 BRA that after PJM

[36] Material and turbine costs increases are based on BLS Producer Price Index for *Construction Materials* and *Components for Construction* and *Turbines and Turbine Generator Sets* between December 2017 and December 2021. Values may not add to 100% due to rounding.

has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of no longer receiving bonus depreciation by applying an additional gross up of 1.017 for CT and 1.021 for CCs. For subsequent auctions, no further gross up will be necessary.

III.H. E&AS Offset Methodology

The VRR Curve prices are indexed to Net CONE, which is derived by subtracting the reference resource's net energy and ancillary service (E&AS) revenues from its Gross CONE. This E&AS offset could be estimated in a variety of ways. PJM originally estimated it based on actual historical electricity and natural gas prices over the past 3 years. In 2020, PJM adopted a forward-looking approach to calculating the E&AS offset based on forward prices for electricity and natural gas, with hourly shapes based on historical data. FERC subsequently ordered PJM in December 2021 to revert back to the historical method because the forward methodology had been implemented along with PJM's proposed Reserve Pricing Reforms that FERC eventually rejected.

We continue to recommend calculating E&AS on a forward basis over a historical approach. As discussed in our prior reviews, the forward E&AS offset is superior because it reflects expected market conditions that developers will face upon entry into the market. The methodology we helped PJM develop is analytically rigorous, based on forward market data for electricity and natural gas. It is similar to approaches we have implemented for clients and have seen other investors use to estimate their future net E&AS revenues (and, by extension, to estimate how much they would need to earn from the capacity market to enter). By contrast, the backward looking approach reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract (with a willingness-to-pay indexed to estimated Net CONE). Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather conditions that substantially distort the calculation and make it unduly volatile.[37]

However, both historical and forward methods rely on market prices that recently have reflected installed capacity well above the reserve requirement, which can perpetuate disequilibria. When supply is scarce, for example, the E&AS offset will increase and scale down the VRR curve thus

[37] For the same reasons, we recommend forward E&AS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, even if this is not implemented, we still recommend using a forward E&AS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected E&AS revenues.

buy less capacity just when it is needed. This could be avoided by adjusting the E&AS offset to what they would be at the target reserve margin, as NYISO and ISO-NE attempt to do. However, the need for an adjustment is not necessarily clear, without knowing what beliefs about reserve margins underlie forward market prices. Any equilibrium E&AS offset would rely on market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices.

Assuming PJM pursues a forward approach again, we reviewed several aspects of its approach and provide the following recommendation:

- Electric Hub Mapping: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices;
- Natural Gas Hub Mapping: Switch EKPC gas hub from Columbia-App TCO to MichCon; otherwise current gas hub mapping supported by recent prices;
- Ancillary Service Prices: Remove regulation revenues from the calculation of the E&AS offset and scale historical hourly sync and non-sync reserve prices by forward energy prices.

Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate.

PJM also requested that we review the approach for calculating the energy efficiency wholesale energy savings to determine whether the utility EE programs included in the analysis continue to be reasonable. Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts. The current sample includes the largest utilities in each state that provides sufficient detail for the analysis. Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample.

III.I. Implications for Net CONE

III.I.1. Indicative E&AS Offsets

The application of the E&AS offset methodology in Section III.H results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, removal of regulation revenue, and updates to other operating characteristics associated with the technical specifications for the CC.[38] Table 19 shows the effect of each of these changes on the forward-looking 2023/24 E&AS revenue offset by zone for the CC based on simulations provided by PJM staff.

38 Other parameter updates include updated operating characteristics associated with the most recent turbine models, the addition of dry-cooling, and the 1x1 single shaft CC configuration.

TABLE 19: UPDATED 2023/24 CC E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	CC			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$168	$2	-$24	$146
DPL	$216	$3	-$23	$196
JCPL	$166	$2	-$24	$143
PECO	$184	$14	-$23	$174
PSEG	$162	$2	-$24	$140
RECO	$172	$2	-$23	$151
CONE Area 2				
BGE	$254	$4	-$20	$239
PEPCO	$197	$10	-$21	$185
CONE Area 4				
METED	$212	$15	-$22	$205
PENELEC	$320	$7	-$17	$310
PPL	$190	$15	-$22	$182
CONE Area 3				
AEP	$242	$8	-$21	$229
APS	$281	$5	-$19	$267
ATSI	$208	$44	-$21	$231
COMED	$179	$11	-$22	$168
DAY	$223	$45	-$21	$247
DEOK	$214	$43	-$21	$237
DUQ	$225	$15	-$20	$219
DOM	$195	$9	-$21	$183
EKPC	$246	$14	-$21	$239
RTO	**$189**	**$11**	**-$23**	**$177**

Note: The “Current 2023/24 E&AS” reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020. The “Updated 2023/24 EAS” values do not reflect changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC’s zone.

III.I.2. Indicative Net CONE

Net CONE is the estimated annualized fixed costs of new entry, or Gross CONE, of the reference resource, net of estimated E&AS margins and expected performance bonus. PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE. We present in Table 20 below indicative CC Net CONE estimates for all LDAs relative to the parameters used in the 2022/23 MOPR (adjusted here to differentiate CONE values by area).

We say "indicative" because the scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach, but does not include estimating the E&AS offsets for the 2026/27 BRA.

TABLE 20: INDICATIVE CC NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	CC 2022/23 MOPR			CC 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$335	$167	$163	$517	$174	$343
DPL	$335	$208	$122	$517	$231	$286
JCPL	$335	$165	$165	$517	$172	$346
PECO	$335	$186	$144	$517	$206	$311
PSEG	$335	$161	$169	$517	$168	$349
RECO	$335	$171	$159	$517	$180	$337
EMAAC	**$335**	**$181**	**$154**	**$517**	**$189**	**$329**
CONE Area 2						
BGE	$345	$254	$76	$506	$279	$227
PEPCO	$345	$191	$139	$506	$219	$287
SWMAAC	**$345**	**$238**	**$107**	**$506**	**$249**	**$257**
CONE Area 4						
METED	$323	$207	$123	$522	$241	$281
PENELEC	$323	$306	$24	$522	$359	$163
PPL	$323	$185	$145	$522	$216	$307
MAAC	**$334**	**$204**	**$130**	**$517**	**$222**	**$294**
CONE Area 3						
AEP	$316	$233	$97	$518	$268	$251
APS	$316	$272	$58	$518	$311	$208
ATSI	$316	$224	$106	$518	$271	$248
COMED	$316	$195	$135	$518	$199	$319
DAY	$316	$235	$95	$518	$288	$230
DEOK	$316	$224	$106	$518	$277	$242
DUQ	$316	$223	$107	$518	$257	$261
DOM	$316	$181	$149	$518	$216	$303
EKPC	$316	$232	$98	$518	$279	$239
OVEC	$316	$260	$70	$518	$303	$216
RTO	**$330**	**$185**	**$146**	**$516**	**$209**	**$307**

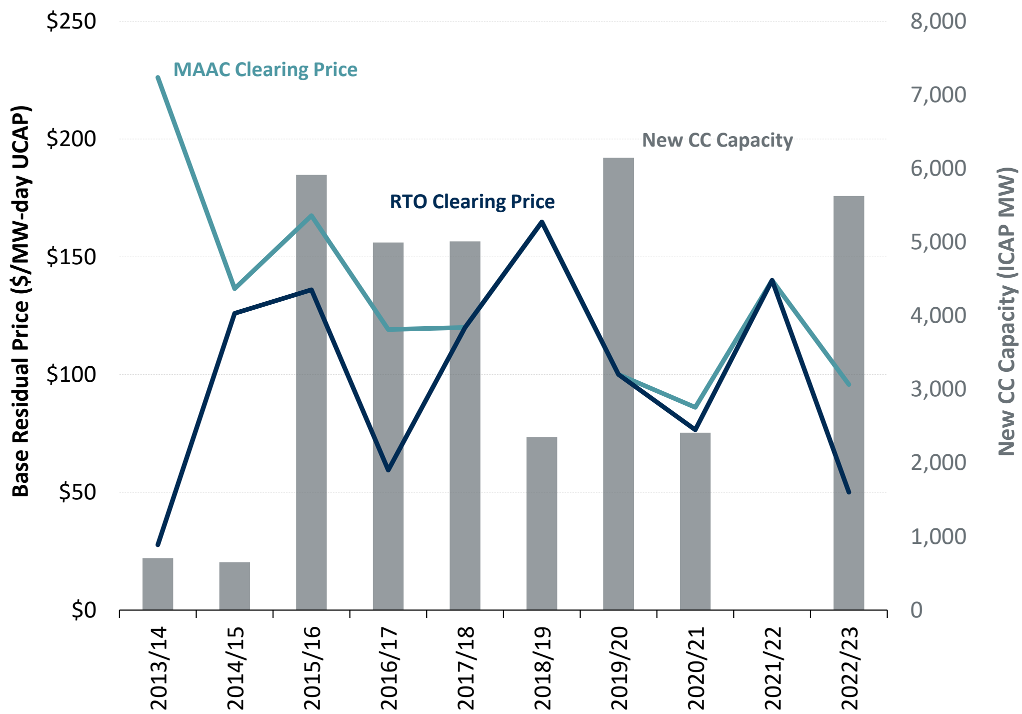
Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

Net CONE is $257–$329/MW-Day (UCAP) across all parent LDAs. Compared to the 2022/23 BRA, the Net CONE roughly doubled for all parent LDAs. Increases in Net CONE are due to the increases in Gross CONE described in Section III.F (cost escalation, decreases in bonus depreciation, and plant design changes) with a slight offset from higher E&AS values. The differences among modeled LDAs and the RTO are similar to the prior.

III.I.3. Comparison to "Empirical Net CONE"

Another informative comparison is to the prices at which actual CCs have been willing to enter the market in past capacity auctions (sometimes referred to as "empirical Net CONE"). Those prices ranged from $75 to $165/MW-Day UCAP in most of the recent auctions, as shown in Figure 10 below. Note that 2022/23 prices should be disregarded as an indicator of willingness to enter since the compressed forward period for that auction meant that new entrants' decisions were already made by the time the auction occurred.

FIGURE 10: HISTORICAL BRA CAPACITY PRICES AND NEW CC CAPACITY



Sources and notes: PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2013/14-2022/23. Please note that the 2022/23 BRA was a compressed auction.

Empirical Net CONE is not a perfect indicator of "true Net CONE" at which capacity could enter at scale—even at the time that capacity entered—because of variability across locations, limited entry in any single auction, and observing only a single clearing price. Some entrants would have entered at prices below the clearing price, whereas uncleared projects, which might have been needed if more retirements or load growth had occurred, would require a higher price. Some may be willing to enter the market at low prices because of their idiosyncratic advantages that cannot be replicated at scale. For example, some past entrants may have enjoyed special opportunities to access natural gas at anomalously low costs earlier in the development of the

Marcellus Shale and export pipelines. Despite these limitations, empirical Net CONE is still a useful benchmark.

Extrapolating backward-looking empirical Net CONE to the future, however, must consider how costs and market conditions have changed. As discussed above, the true cost of entry is in fact increasing due to cost escalation, changes in environmental regulations and plant configurations, and tax laws—by $180/MW-day in our estimation compared to a few years ago. In addition, since the long-term prospects for cash flows have diminished with the industry's transition toward clean energy, entrants may need to front-load their revenues more so than in the past. For example, if they used to assume a 30-year economic life but now assume 20 years, that would further increase Net CONE by $44/MW-day ICAP. Altogether, adding that $180 + $44 to historical empirical Net CONE of $100-165/MW-day, suggests an adjusted benchmark for 2026 of as much as $324-389/MW-day, or $280-345 MW-day without the adjustment for economic life. This is not far from our estimated Net CONE of $257-$329/MW-day across modeled LDAs.

III.I.4. Uncertainty Analysis

There is considerable uncertainty in estimating Net CONE. Most of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, or more if technologies are more constrained by environmental regulations. These examples indicate an uncertainty range on Net CONE of -29% to +16%; the full uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we recommend testing robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

IV. Natural Gas-Fired Combustion Turbines

IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Turbine Model	GE 7HA.02 60HZ
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	361 / 363 / 353 / 350*
Net Heat Rate (HHV in Btu/kWh)	9320 / 9317 / 9304 / 9311*
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	No
Firm Gas Contract	Yes
Special Structural Requirements	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011

Turbine Model	Turbine Class	PJM		US	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric LM6000	Aeroderivative	7	331	69	3,101
General Electric 7FA	Frame	2	330	14	2,462
Pratt & Whitney FT4000	Aeroderivative	2	120	2	120
Rolls Royce Corp Trent 60	Aeroderivative	2	119	2	119
Pratt & Whitney FT8	Aeroderivative	1	57	4	189
Siemens Unknown	N.A.	1	28	2	545
General Electric LMS100	Aeroderivative	0	0	47	4,664
Siemens SGT6-5000F	Frame	0	0	10	1,892
Rolls Royce Corp Unknown	N.A.	0	0	10	599
General Electric 7EA	Small Frame	0	0	7	417
Siemens AG SGT	Frame	0	0	7	401
General Electric 7HA	Frame	0	0	1	330
All Other Turbine Models		0	0	14	1,297
Total		**15**	**985**	**189**	**16,136**

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that the Perryman Unit 6 CT plant built in 2015 in Maryland included in its operating permit to avoid exceeding emissions thresholds.[39]

- Land: Similar to the reference CC, we estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 10 acres of land are for the reference CT.

TABLE 23: COST OF LAND PURCHASED FOR REFERENCE CT

CONE Area	Land Price *($/acre)*	Plot Size Gas CT *(acres)*	Cost Gas CT *($m)*
1 EMAAC	$36,600	10	$0.37
2 SWMAAC	$29,500	10	$0.30
3 Rest of RTO	$16,400	10	$0.16
4 WMAAC	$30,600	10	$0.31

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

Based on the technical specifications for the CT described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 24 below.

[39] The Perryman Unit 6 operating permit is available here: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Test/Constellation%20Perryman%20Renewal%20Title%20V%202018.pdf

TABLE 24: PLANT CAPITAL COSTS FOR CT REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

Capital Costs (in $millions)	CONE Area 1 EMAAC *361 MW*	CONE Area 2 SWMAAC *363 MW*	CONE Area 3 Rest of RTO *353 MW*	CONE Area 4 WMAAC *350 MW*
Owner Furnished Equipment				
Gas Turbines	$78.6	$78.6	$78.6	$78.6
HRSG / SCR	$33.5	$33.5	$33.5	$33.5
Sales Tax	$0.0	$0.0	$0.0	$0.0
Total Owner Furnished Equipment	**$112.1**	**$112.1**	**$112.1**	**$112.1**
EPC Costs				
Equipment				
Other Equipment	$24.1	$24.1	$24.1	$24.1
Construction Labor	$50.6	$37.8	$40.6	$45.0
Other Labor	$16.4	$15.4	$15.6	$16.0
Materials	$8.1	$8.1	$8.1	$8.1
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	$21.1	$19.8	$20.1	$20.5
EPC Contingency	$23.2	$21.7	$22.1	$22.6
Total EPC Costs	**$143.6**	**$127.0**	**$130.6**	**$136.3**
Non-EPC Costs				
Project Development	$12.8	$12.0	$12.1	$12.4
Mobilization and Start-Up	$2.6	$2.4	$2.4	$2.5
Net Start-Up Fuel Costs	-$0.6	-$0.6	$0.1	-$0.5
Electrical Interconnection	$7.8	$7.8	$7.6	$7.6
Gas Interconnection	$33.7	$33.7	$33.7	$33.7
Land	$0.4	$0.3	$0.2	$0.3
Fuel Inventories	$0.0	$0.0	$0.0	$0.0
Non-Fuel Inventories	$1.3	$1.2	$1.2	$1.2
Owner's Contingency	$4.6	$4.6	$4.6	$4.6
Emission Reduction Credit	$0.0	$0.0	$0.0	$0.0
Financing Fees	$7.0	$6.6	$6.7	$6.8
Total Non-EPC Costs	**$69.6**	**$68.0**	**$68.7**	**$68.6**
Total Capital Costs	**$325.3**	**$307.1**	**$311.4**	**$317.0**
Overnight Capital Costs ($million)	**$325**	**$307**	**$311**	**$317**
Overnight Capital Costs ($/kW)	**$902**	**$846**	**$882**	**$906**
Installed Cost ($/kW)	**$945**	**$887**	**$925**	**$949**

IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

TABLE 25: O&M COSTS FOR CT REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC 361 MW	2 SWMAAC 363 MW	3 Rest of RTO 353 MW	4 WMAAC 350 MW
Fixed O&M (2026$ million)				
LTSA Fixed Payments	$0.3	$0.3	$0.3	$0.3
Labor	$1.2	$1.2	$0.9	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.3	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$2.2	$0.3
Insurance	$2.0	$1.8	$1.9	$1.9
Firm Gas Contract	$4.4	$5.4	$7.1	$6.3
Working Capital	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2026$ million)	**$9.5**	**$14.4**	**$13.5**	**$10.9**
Levelized Fixed O&M (2026$/MW-yr)	**$26,300**	**$39,600**	**$38,300**	**$31,300**
Variable O&M (2026$/MWh)				
Consumables, Waste Disposal, Other VOM	1.19	1.18	1.15	1.22
Total Variable O&M (2026$/MWh)	**1.19**	**1.18**	**1.15**	**1.22**
Major Maintenance - Starts Based ($/factored start, per turbine)	**21,170**	**21,170**	**21,170**	**21,170**

IV.D.CONE Results and Comparisons

Table 26 shows plant capital costs, annual fixed costs, and levelized CONE estimates for the CT reference plant for the 2026/27 delivery year. CONE estimates range from $378/MW-day in EMAAC to $403/MW-day in the Rest of RTO. Note that we assumed accelerated tax depreciation based on the 15-year MACRS for the CT to the depreciable costs after accounting for bonus depreciation.

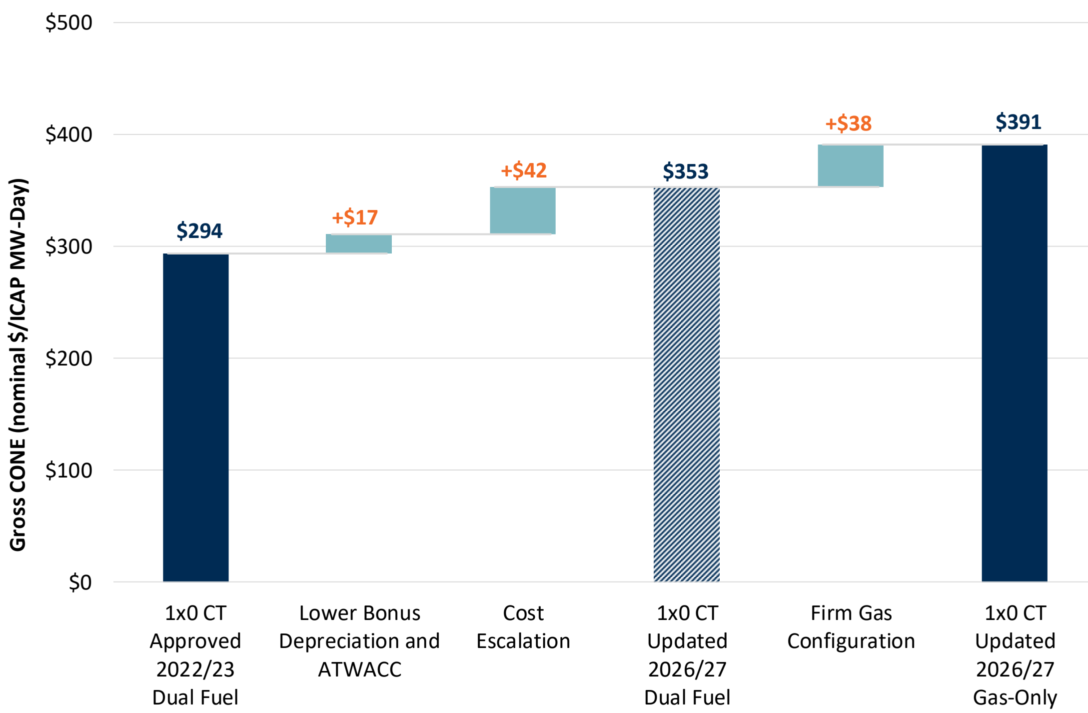
TABLE 26: ESTIMATED CONE FOR CT PLANTS FOR 2026/27 IN 2026$ AND ICAP MW

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$325	$307	$311	$317
[2]	Installed (inc. IDC)	*$m*		$341	$322	$326	$332
[3]	First Year FOM	*$m/yr*		$9	$14	$14	$11
[4]	**Net Summer ICAP**	***MW***		**361**	**363**	**353**	**350**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$902	$846	$882	$906
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$945	$887	$925	$949
[7]	Levelized FOM	*$/kW-yr*		$33	$44	$45	$39
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		11.7%	11.6%	11.6%	11.6%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$138,000**	**$141,700**	**$147,100**	**$144,000**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$378**	**$388**	**$403**	**$395**

Similar to the CC, the CT CONE estimates vary by CONE Area primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

The 2026/27 CT CONE estimates are considerably higher than in PJM's Base Residual Auction for the 2022/23 Delivery Year as shown in Figure 11. Similar to the presentation of CC CONE drivers, the attribution of changes to each element depends on the order in which the changes are implemented in our model. We estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, firm gas configuration.

FIGURE 11: DRIVERS OF HIGHER CT 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The decline to 20% bonus depreciation by 2026 increases CONE by $21/MW-day (ICAP). The ATWACC decreased to 8.0%, decreasing CONE by $4/MW-day (ICAP), for a net effect of $17/MW-Day (ICAP).
- Cost Escalation: Cost escalation is lower relative to the CC due to a lower portion of materials and labor costs associated with the CT. As a result, the total cost escalation to 2026/27 adds $42/MW-Day (ICAP) to the 1x0 CT 2022/23 Dual Fuel CONE value.
- Firm Gas Configuration: The use of firm gas transportation contracts, adds $38/MW-Day (ICAP) to the 1x0 CT Updated Dual Fuel 2026/27 CONE.

IV.E. Implications for Net CONE

IV.E.1. Indicative E&AS Offsets

The E&AS offset methodology described for CCs would also apply to CTs, but recognizing two differences related to CTs' operation as peaking plants that are generally committed day-of. As peaking plants, their dispatch depends more on the hourly volatility of prices that cannot be observed directly in forward markets and are instead taken from historical hourly price shapes. Since historical prices do not fully reflect future conditions, the E&AS offset estimates for CTs may be subject to more uncertainty than for CCs (at least on a percentage basis). This observation does not lead to an obvious recommendation for improving the E&AS offset methodology for CTs but does contribute to our assessment of uncertainty in selecting a suitable reference resource, as discussed above.

The fact that CTs are generally committed day-of does require a slight adjustment to fuel cost inputs in the E&AS offset calculation. As we noted in our 2018 Study, "PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM's Operating Agreement to the variable operating costs of the CTs in the simulations."[41] This time, we are not recommending a "10% adder" that FERC has recently rejected but, more precisely a 10% increase over (day-ahead) gas daily index prices (and no adder on CT VOM costs). This should provide reasonable and necessary adjustment to get more accurate fuel cost inputs.

The application of the CT E&AS offset methodology discussed above results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, then removal of regulation revenue. Table 27 shows the 2023/24 E&AS revenue offset by zone using the updated methodology.

41 2018 VRR Curve Study, pp. 23-24.

TABLE 27: UPDATED 2023/24 CT E&AS REVENUE OFFSET BY ZONE

All values in nominal $/MW-day ICAP	CT			
	Current 2023/24 EAS	Updated Operating Costs	Removed Regulation	Updated 2023/24 EAS
CONE Area 1				
AECO	$45	-$4	-$8	$33
DPL	$76	-$2	-$8	$65
JCPL	$43	-$4	-$8	$32
PECO	$48	$4	-$7	$45
PSEG	$41	-$4	-$8	$30
RECO	$48	-$3	-$8	$36
CONE Area 2				
BGE	$93	$6	-$9	$89
PEPCO	$57	-$1	-$7	$49
CONE Area 4				
METED	$65	$8	-$8	$65
PENELEC	$150	$28	-$12	$166
PPL	$52	$5	-$7	$49
CONE Area 3				
AEP	$83	$9	-$12	$79
APS	$114	$17	-$13	$118
ATSI	$66	$16	-$8	$75
COMED	$47	-$6	-$7	$34
DAY	$70	$21	-$8	$83
DEOK	$74	$17	-$8	$83
DUQ	$81	$15	-$8	$89
DOM	$56	-$1	-$7	$48
EKPC	$80	$11	-$10	$81
RTO	**$48**	**-$1**	**-$8**	**$39**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020, including a 10% adder on all variable costs. The "Updated 2023/24 EAS" values do not reflect recommended changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

IV.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the Net CONE shown for the reference CC. Table 28 shows the indicative CT Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 28: INDICATIVE 2026/27 CT NET CONE

All values in nominal $/MW-day UCAP	CT 2022/23 BRA			CT 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE	CONE	EAS	Net CONE
CONE Area 1						
AECO	$312	$47	$265	$397	$48	$349
DPL	$312	$76	$236	$397	$85	$312
JCPL	$312	$45	$267	$397	$47	$351
PECO	$312	$54	$258	$397	$62	$336
PSEG	$312	$43	$268	$397	$44	$353
RECO	$312	$50	$262	$397	$52	$346
EMAAC	**$312**	**$52**	**$259**	**$397**	**$56**	**$341**
CONE Area 2						
BGE	$317	$90	$226	$408	$113	$315
PEPCO	$317	$57	$260	$408	$67	$315
SWMAAC	**$317**	**$74**	**$243**	**$408**	**$93**	**$315**
CONE Area 4						
METED	$305	$67	$238	$415	$85	$315
PENELEC	$305	$139	$166	$415	$200	$210
PPL	$305	$54	$250	$415	$67	$315
MAAC	**$311**	**$66**	**$245**	**$404**	**$79**	**$320**
CONE Area 3						
AEP	$305	$77	$227	$424	$101	$315
APS	$305	$102	$203	$424	$146	$315
ATSI	$305	$74	$230	$424	$96	$315
COMED	$305	$57	$248	$424	$49	$421
DAY	$305	$78	$226	$424	$105	$315
DEOK	$305	$81	$224	$424	$106	$315
DUQ	$305	$80	$224	$424	$112	$315
DOM	$305	$54	$250	$424	$65	$315
EKPC	$305	$76	$229	$424	$103	$315
OVEC	$305	$89	$216	$424	$130	$315
RTO	**$309**	**$49**	**$260**	**$411**	**$55**	**$356**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

V. Battery Energy Storage Systems (BESS)

During the stakeholder process, several stakeholders raised concerns about whether natural-gas-fired resources (either CCs or CTs) will be feasible to build in certain zones due to state policies that require a decreasing portion of the generation mix to come from GHG-emitting resources. Based on this input, we reviewed several non-emitting resources to include as possible reference resources and determined that the 4-hour BESS best meets the reference resource screening criteria described in Section II above.

While 4-hour BESS is currently not recommended as the reference resource in any zone, its CONE value provides an initial estimate for PJM and its stakeholders a starting point for future reviews or before then if the recommended reference resource, the gas-fired CC, is determined to be infeasible to be built within the Quadrennial Review period.

V.A. Technical Specifications

We developed the cost estimates for the 4-hour BESS based on the specifications listed in Table 29 below. We assumed the facility is sized for 200 MW at the point of interconnection, based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

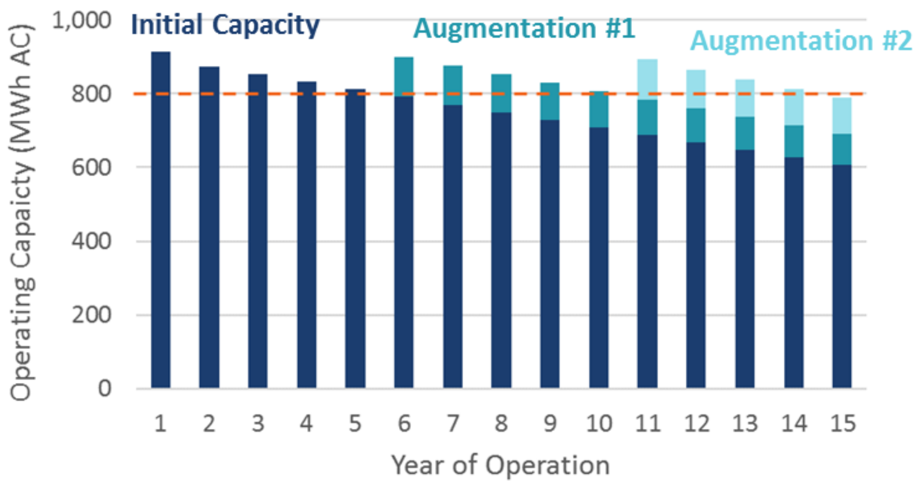
TABLE 29: BESS TECHNICAL SPECIFICATIONS

Plant Characteristic	Specification
Chemistry	Lithium-ion
Installation Configuration	Containerized
Rated Output Power (at POI)	200 MW-ac
Duration	4 Hours
Installed Energy Capacity	1,030 MWh-dc
Annual Capacity Degradation	4% in Year 1, then 2% per year
Augmentations	Year 5 and Year 10
Use Case	Daily Cycling
Round Trip Efficiency	85%
Economic Life	15 Years
Salvage Value	$0

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4% in the first year and 2% in subsequent years, assuming daily cycling and a 5% minimum state of charge.[42] Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations that reduces the initial capital costs of the facility and may allow the owner to take advantage of declining module costs, depending on future cost trends. To account for degradation of the energy capacity, our cost estimate assumes that the facility will include an initial 13% overbuild, or 135 MWh-dc, with augmentations planned for Year 5 and Year 10. This is currently a common approach developers are taking, based on S&L's recent project experience, to reduce mobilization costs of frequent augmentation while still taking advantage of future costs declines.

42 Degradation occurs due to many factors, including time, ambient conditions, state-of-charge, operational profiles, depth of discharge and manufacturing defects.

FIGURE 12: BESS EENRGY CAPCITY OVER 15 YEAR LIFE



Accounting for the assumed overbuild, minimum state of charge, and on-site losses, the total installed energy capacity is 1,030 MWh-dc, accounting for AC and inverter losses of 6.2%.[43]

TABLE 30: BESS SIZING ASSUMPTIONS

Component	Value
Rated AC Output Power (at POI)	**200 MW-ac**
AC Losses	4.6%
Inverter Losses	1.6%
Gross DC Power Output	**212 MW-dc**
Minimum State of Charge	5.0%
Duration	4 hours
Gross Energy Capacity	**895 MWh-dc**
Overbuild due to Degradation	13%, or 135 MWh-dc
Installed Energy Capacity	**1,030 MWh-dc**

Note: Gross Energy Capacity represents the required capacity to achieve nameplate rated output power on the first day of operation

[43] AC losses include power control system and generator step-up transformer losses, line losses, and auxiliary load.

V.B. Capital Costs

As explained in more detail below, we estimated the 4-hour BESS CONE value using a top-down cost estimating approach that involves less detailed specification of the resource and its location for developing cost estimates. S&L estimated the EPC costs based on recent project data, establishing unitized costs for project components and scaling to the selected reference technology specifications with adjustments to account for labor rates in each CONE Area. S&L then verified the total installed costs against publicly available cost estimates for similar BESS resources.

We estimated the non-EPC costs using similar assumptions as the CC and CT for the per-kW costs of electrical interconnection and per-acre land costs. The remaining non-EPC costs components are estimated based on a percentage of total EPC with the same assumption as the CC and CT for project development, mobilization and start-up, and financing fees. We assumed a lower Owner's Contingency of 5% of BESS equipment costs instead of 8% for the CC and CT based on the larger share of costs covered by the EPC contract.

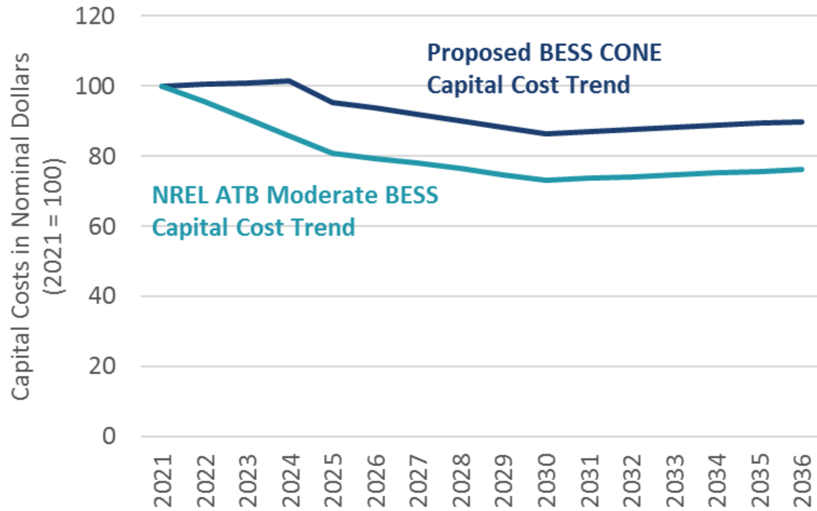
Based on the technical specifications for the reference BESS described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 31 below. EPC costs are primarily driven by the costs of the batteries and enclosures, which is currently estimated to be about $190/kWh-dc (in 2021 dollars). The EPC Contractor Fee and Contingency costs are assumed to be incorporated into the other BESS EPC costs.

TABLE 31: PLANT CAPITAL COSTS FOR BESS REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*200 MW*	*200 MW*	*200 MW*	*200 MW*
EPC Costs				
BESS Equipment				
Batteries and Enclosures	$193.5	$193.5	$193.5	$193.5
PCS and BOP Equipment	$29.0	$29.0	$29.0	$29.0
Project Management	$11.8	$9.4	$10.0	$10.8
Construction & Materials	$58.7	$46.9	$49.6	$53.6
Sales Tax	$0.0	$0.0	$0.0	$0.0
EPC Contractor Fee	Included	Included	Included	Included
EPC Contingency	Included	Included	Included	Included
Total EPC Costs	**$293.0**	**$278.8**	**$282.0**	**$286.9**
Non-EPC Costs				
Project Development	$14.7	$13.9	$14.1	$14.3
Mobilization and Start-Up	$2.9	$2.8	$2.8	$2.9
Owner's Contingency	$11.1	$11.1	$11.1	$11.1
Electrical Interconnection	$4.1	$4.1	$4.1	$4.1
Land	$0.4	$0.3	$0.2	$0.4
Working Capital	$0.0	$0.0	$0.0	$0.0
Financing Fees	$1.3	$1.3	$1.3	$1.3
Total Non-EPC Costs	**$34.6**	**$33.6**	**$33.6**	**$34.1**
Total Capital Costs	**$327.6**	**$312.4**	**$315.7**	**$321.0**
Overnight Capital Costs ($million)	**$328**	**$312**	**$316**	**$321**
Overnight Capital Costs ($/kW)	**$1,638**	**$1,562**	**$1,578**	**$1,605**
Installed Capital Costs ($/kW)	**$1,725**	**$1,646**	**$1,663**	**$1,691**
Installed Capital Costs ($/kWh)	**$409**	**$390**	**$395**	**$401**

Similar to the CC and CT, all equipment and material costs are initially estimated by S&L in 2021 dollars and escalated to the construction period for an online date of June 1, 2026 based on a 16-month construction drawdown schedule for BESS resources. We estimate the overnight capital cost for the BESS incurred during the construction period, as shown in Figure 13 below. S&L estimates that costs will decline in real terms by -1.5% per year from 2021 to 2024 (or +1.4% per year in nominal terms, given assumed inflation of 2.9% per year), based on contract data, trends, and expectations expressed by suppliers for projects currently in development. From 2024 to 2026, we then assume costs will decline in nominal terms based on the 2021 NREL Annual Technology Baseline Moderate cost projections. We use this approach as well for estimating augmentation costs in 2031 (Year 5) and 2036 (Year 10).

FIGURE 13: PROJECTED BESS CAPITAL COST TRENDS



V.C. Operation and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. Table 9 summarizes the annual fixed O&M costs, variable O&M costs, and augmentation costs in Year 5 and Year 10 for BESS with an online date of June 1, 2026. The annual O&M costs primarily include the fixed costs of the O&M contract for the facility and the costs of operating insurance.

As shown in Figure 12 above, the BESS storage capacity will fall below 800 MWh-ac in Year 6 based on the assumed initial overbuild and degradation rates. To maintain its 4-hour duration at 200 MW of output power through the economic life of the asset, we assume the developer will add 124 MWh-dc of additional battery modules in Year 5 at a cost of $30.5 million (in 2031 dollars) and another 124 MWh-dc of capacity in Year 10 at $33.1 million (in 2036 dollars).[44]

[44] Augmentation costs reflect the current estimate of module of $190/kWh plus a 20% markup for mobilization and installation costs and the projected trend in module costs shown in Figure 13.

TABLE 32: O&M COSTS FOR BESS REFERENCE RESOURCE

O&M Costs	CONE Area 1 EMAAC *200 MW*	2 SWMAAC *200 MW*	3 Rest of RTO *200 MW*	4 WMAAC *200 MW*
Fixed O&M Components				
O&M Contract Fixed Payments	$2.7	$2.7	$2.7	$2.7
BOP and Substation O&M	$0.1	$0.1	$0.1	$0.1
Station Load / Aux Load	$0.4	$0.3	$0.3	$0.4
Miscellaneous Owner Costs	$0.3	$0.2	$0.3	$0.3
Operating Insurance	$1.3	$1.2	$1.3	$1.3
Land Lease or Property Taxes	$2.3	$4.4	$2.1	$2.0
Fixed O&M (2026$ million)	**$7.1**	**$9.0**	**$6.7**	**$6.7**
Fixed O&M ($/kW-yr)	**$35.3**	**$44.8**	**$33.6**	**$33.7**
Augmentation				
Year 5 Costs (2031$ million)	**$30.5**	**$30.5**	**$30.5**	**$30.5**
Year 10 Costs (2036$ million)	**$33.1**	**$33.1**	**$33.1**	**$33.1**
Levelized Augmentation Costs ($/kW-yr)	**$22.3**	**$22.3**	**$22.3**	**$22.3**
Total Levelized Fixed Costs ($/kW-yr)	**$57.7**	**$67.1**	**$55.9**	**$56.1**

The total levelized fixed O&M costs represent the total contribution of these costs to the CONE value, including both the annual fixed costs ($23/kW-year to $42/kW-year) and the levelized costs of the two capacity augmentations (about $28/kW-year). While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. All O&M and augmentation costs for the BESS are accounted for in Table 32 and the variable O&M costs are assumed to be $0.

V.D. CONE Estimates

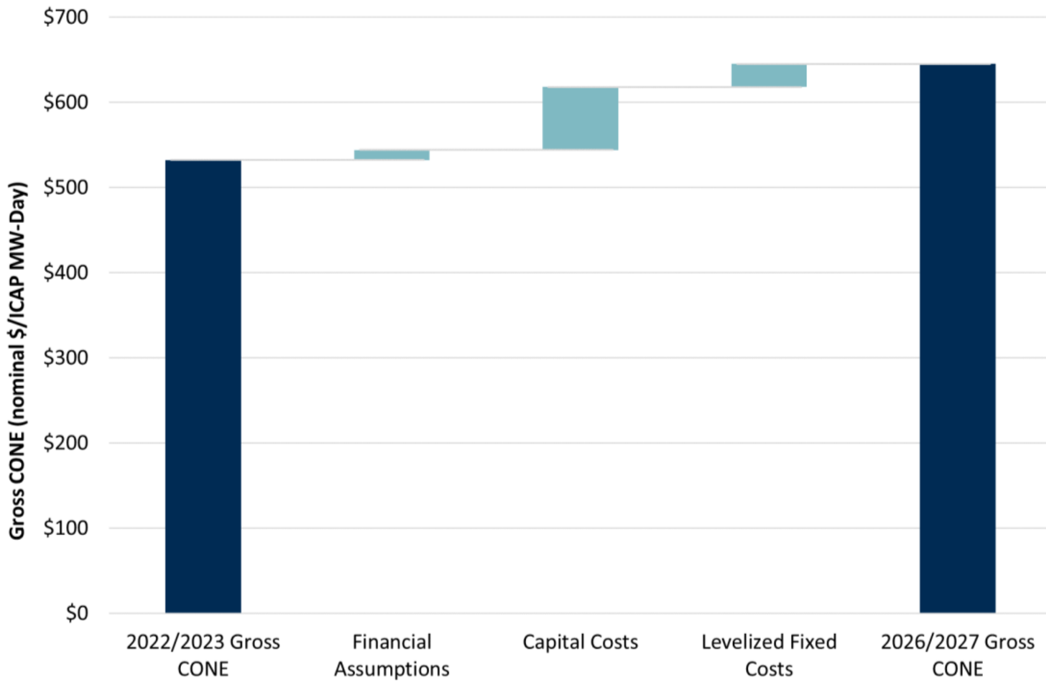
The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 33 summarizes plant capital costs, annual fixed costs, and levelized CONE estimates for the BESS reference resource for the 2026/27 delivery year. The CONE estimates range from $653/MW-day in Rest of RTO to $678/MW-day in EMAAC.

TABLE 33: ESTIMATED CONE FOR BESS FOR 2026/27 IN 2026$ AND ICAP MW

			4-Hour Battery Storage			
			EMAAC	SWMAAC	Rest of RTO	WMAAC
	Net Summer ICAP	*MW*	**200**	**200**	**200**	**200**
	Gross Costs					
[1]	Overnight	*$m*	$328	$312	$316	$321
[2]	Installed (inc. IDC)	*$m*	$345	$329	$333	$338
[3]	First Year FOM	*$m/yr*	$7	$9	$7	$7
[4]	Year 5 Augmentation	*$m*	$31	$31	$31	$31
[5]	Year 10 Augmentation	*$m*	$33	$33	$33	$33
	Unitized Costs					
[7]	Overnight	*$/kW*	$1,638	$1,562	$1,578	$1,605
[8]	Installed (inc. IDC)	*$/kW*	$1,725	$1,646	$1,663	$1,691
[9]	Levelized Fixed Costs	*$/kW-yr*	$66	$69	$64	$64
[10]	**After-Tax WACC**	*%*	**7.9%**	**8.0%**	**8.0%**	**8.0%**
[11]	Effective Charge Rate	*%*	11.1%	11.0%	11.1%	11.1%
[12]	**Updated CONE**	***$/MW-yr***	**$247,400**	**$240,900**	**$238,400**	**$241,500**
[13]	**Updated CONE**	***$/MW-day***	**$678**	**$660**	**$653**	**$662**

Similar to the CC and CT, the 2026/27 BESS CONE estimates are considerably higher than PJM's estimated CONE for the 2022/23 Delivery Year Base Residual Auction, as shown in Figure 14. PJM estimated the 2022/23 CONE based on cost estimates from the NREL Annual Technology Baseline. As described above, the updated estimates for the 2026/27 auction reflect more detailed specifications for a 200 MW facility in the PJM market and recent cost estimates based on actual projects currently under development, including recent cost escalation. As shown in Figure 13 above, the current outlook for BESS capital costs are about 15% higher than those projected by NREL in its latest ATB. The higher capital costs also reflect the assumed overbuild of capacity to account for degradation, whereas NREL assumed no overbuild and annual augmentation. The higher O&M costs reflect the recent costs of maintenance contracts as well as a more up-to-date outlook for future augmentation costs.

FIGURE 14: DRIVERS OF HIGHER BESS 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)



V.E. Implications for Net CONE

V.E.1. Indicative E&AS Offsets

Similar to the CC and CT, we recommend removing regulation revenues from the calculation of the E&AS offset for BESS. The regulation market is unlikely to continue to support similar prices in the future with the addition of significant BESS resources, especially in the case in which BESS resource are one of the primary resources that enter the market to meet future reserve requirements.

Removing regulation revenues has a greater impact on BESS E&AS offset than the CC and CT though because it currently makes up the majority of its revenues. Table 34 shows the current and updated 2023/24 E&AS revenue offset by zone with the steep decrease caused by the removal of regulation revenues.

TABLE 34: UPDATED 2023/24 BESS E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

All values in nominal $/MW-day ICAP	4-Hour BESS		
	Current 2023/24 EAS	Removed Regulation	Updated 2023/24 EAS
CONE Area 1			
AECO	$414	-$294	$120
DPL	$427	-$285	$142
JCPL	$413	-$295	$118
PECO	$413	-$295	$118
PSEG	$414	-$294	$120
RECO	$419	-$291	$128
CONE Area 2			
BGE	$428	-$267	$161
PEPCO	$423	-$274	$149
CONE Area 4			
METED	$417	-$286	$132
PENELEC	$419	-$290	$128
PPL	$416	-$292	$124
CONE Area 3			
AEP	$418	-$286	$132
APS	$418	-$284	$134
ATSI	$419	-$284	$135
COMED	$425	-$281	$144
DAY	$420	-$281	$139
DEOK	$421	-$280	$141
DUQ	$421	-$283	$139
DOM	$424	-$276	$149
EKPC	$418	-$285	$134
OVEC	$407	-$295	$113
RTO	**$343**	**-$215**	**$128**

Sources and notes: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020.

V.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the BESS Net CONE shown for the reference CC. Table 28 Table 35 shows the indicative BESS Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 35: INDICATIVE BESS 2026/2027 NET CONE ($/MW-DAY UCAP)

All values in nominal $/MW-day UCAP	BESS 2026/27 Brattle Estimate		
	CONE	EAS	Net CONE
CONE Area 1			
AECO	$858	$178	$679
DPL	$858	$208	$649
JCPL	$858	$175	$682
PECO	$858	$175	$683
PSEG	$858	$179	$679
RECO	$858	$189	$668
EMAAC	**$858**	**$184**	**$674**
CONE Area 2			
BGE	$875	$234	$641
PEPCO	$875	$219	$656
SWMAAC	**$875**	**$227**	**$648**
CONE Area 4			
METED	$843	$194	$648
PENELEC	$843	$190	$653
PPL	$843	$184	$659
MAAC	**$857**	**$193**	**$663**
CONE Area 3			
AEP	$830	$195	$635
APS	$830	$198	$632
ATSI	$830	$199	$631
COMED	$830	$211	$619
DAY	$830	$204	$625
DEOK	$830	$208	$622
DUQ	$830	$204	$626
DOM	$830	$218	$612
EKPC	$830	$197	$633
OVEC	$830	$168	$662
RTO	**$851**	**$189**	**$662**

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

VI. List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
Btu	British Thermal Units
CAISO	California Independent System Operator
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPI	Consumer Price Index
CT	Combustion Turbine
DCP	Dominion Cove Point
DJIA	Dow Jones Industrial Average
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
FERC	Federal Energy Regulatory Commission
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kWh	Kilowatt-Hours
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million

MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NO_x	Nitrogen Oxides
NPV	Net Present Value
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VOC	Volatile Organic Compounds
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Combined-Cycle and Combustion Turbine Cost Details

A.1 Technical Specifications

The 2018 PJM CONE study demonstrated that the market was shifting away from the F-class and G-class frame type turbines that had been the dominant turbines over the prior several decades and with over half of the CC plants installed or under construction in PJM. Today, developers even more definitively exhibit preference for H/J-class turbines. Table 36 shows 72% and 58% of CC capacity under construction (since 2018) is from H/J-class turbines in PJM and the U.S., respectively. Among all such turbines, developers continue to select GE 7HA turbine, building on the industry's many turbine-years of operating experience with that make and model. Other equivalent machines to the GE H-class machine such as the Siemens SGT6-8000H or the Mitsubishi M501J currently have lower market penetration.

TABLE 36: TURBINE MODEL OF COMBINED-CYCLE PLANTS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018

Turbine Model	PJM Installed Capacity *(MW)*	US Installed Capacity *(MW)*
General Electric 7HA	7,211	12,203
Mitsubishi M501J	3,645	3,645
Siemens SGT6-8000H	1,856	1,856
Mitsubishi M501G	1,444	4,015
General Electric 7F	828	4,130
Siemens SGT6-5000F	755	1,426
General Electric A650	717	717
Siemens SGT6-500	703	703
General Electric 6B.03	276	276
General Electric GRT	210	210
General Electric MS7001	0	1,000
Siemens SGT6-2000	0	232
Siemens SGT6-800	0	224
Solar Turbines Titan 130	0	29
Total	**17,645**	**30,666**
F/G Class Total	3,940	10,485
H/J Class Total	12,712	17,704

Sources and notes: Data is from Ventyx Energy Velocity Suite and S&P Global Market Intelligence, Accessed August 2021.

Sargent & Lundy reviewed the operational characteristics of starting up each reference resource and updated the parameters PJM includes in its historical simulations for setting the Net E&AS revenue offset in Table 37.

TABLE 37: RECOMMENDED OPERATING PARAMETERS FOR REFERENCE RESOURCES

Parameter	Unit	CT	CC
Installed Capacity	*MW*	367	1,182
Minimum Stable Level	*MW*	140	176
Ramp Rate	*MW/min*	15	30
Time to Start	*mins*	21	120
Minimum Runtime	*hours*	2	4
NOx Rate	*lb/MMBtu*	0.0093	0.0074
SO2 Rate	*lb/MMBtu*	0.0006	0.0006
Startup Gas Usage	*MMBtu/start*	456	7,988
Startup NOx Emissions	*lb/start*	55	160

A.2 Construction Labor Costs

Labor costs are comprised of "construction labor" associated with the EPC scope of work and "other labor" that includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Labor rates have been developed by S&L through a survey of prevalent wages in each region in 2021. The labor costs for a given task are based on trade rates weighted by the combination of trades required. In areas where multiple labor pools can be drawn upon the trade rates used are the average of the possible labor rates. The labor costs are based on a 5-day 10-hour workweek with per-diem included to attract skilled labor. Site overheads are carried as indirect costs, which is consistent with current industry practice whereas in 2014 site overheads were carried in the labor rates.

A summary of construction labor cost assumptions is shown below in Table 38.

TABLE 38: CONSTRUCTION LABOR COST ASSUMPTIONS

		EMAAC	SWMAAC	Rest of RTO	WMAAC
1x0 CT Plant					
2021 Construction Labor Hours	*hours*	256,453	239,508	243,744	256,453
2021 Weighted Average Crew Rates	*$*	137.66	118.34	122.59	122.44
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$41,657,600	$31,178,500	$33,466,500	$37,051,400
2021 Construction Labor Costs	*$/kW*	115	86	95	106
Double Train 1x1 CC Plant					
2021 Construction Labor Hours	*hours*	1,809,038	1,687,939	1,718,213	1,809,038
2021 Weighted Average Crew Rates	*$*	143.62	127.97	129.48	129.85
2021 Productivity Factor	--	1.18	1.10	1.12	1.18
2021 Construction Labor Costs	*$*	$306,589,500	$237,598,100	$249,164,300	$277,181,900
2021 Construction Labor Costs	*$/kW*	294	227	244	274

Engineering, procurement, and project services are taken as 5% of project direct costs. Construction management and field engineering is taken as 2% of project direct costs. Start-up and commissioning is taken as 1% of project direct costs. These values are consistent with the 2018 CONE Study and are in-line with recent projects in which S&L has been involved.

A.3 Net Startup Fuel Costs

We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume zone-specific gas prices, including Transco Zone 6 Non-New York prices for EMAAC, Transco Zone 5 prices for SWMAAC, Columbia Appalachia prices for Rest of RTO, and Transco Leidy Receipts for WMAAC. All gas prices were calculated by using future/forward natural gas prices from OTC Global Holdings as of 10/10/2021 to estimate 2022 gas prices.
- **Electric Energy:** estimate prices based on zone-specific energy prices for the location of the reference resources in each CONE Area: AECO for EMAAC, PEPCO for SWMAAC, AEP for Rest of RTO, and PPL for WMAAC;[45] average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

[45] Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

TABLE 39: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING

	Energy Production			Fuel Consumption			
	Energy Produced	Energy Price	Energy Sales Credit	Natural Gas	Natural Gas Price	Natural Gas Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT							
1 Eastern MAAC	178,130	$36.24	$6.46	1,636,480	$3.61	$5.9	-$0.6
2 Southwest MAAC	179,290	$36.24	$6.50	1,647,134	$3.61	$5.9	-$0.6
3 Rest of RTO	173,913	$32.45	$5.64	1,598,262	$3.61	$5.8	$0.1
4 Western MAAC	172,584	$36.24	$6.25	1,586,224	$3.61	$5.7	-$0.5
Gas CC							
1 Eastern MAAC	1,027,945	$36.24	$37.26	6,468,335	$3.61	$23.3	-$13.9
2 Southwest MAAC	1,034,170	$36.24	$37.48	6,509,687	$3.61	$23.5	-$14.0
3 Rest of RTO	1,003,905	$32.45	$32.57	6,316,673	$3.61	$22.8	-$9.8
4 Western MAAC	996,320	$36.24	$36.11	6,269,141	$3.61	$22.6	-$13.5

Sources and notes: Energy production and fuel consumption estimated by S&L. Energy prices estimated by Brattle based on approach discussed in Section II.B of VRR curve report. Gas prices from OTC Global Holdings as of 10/10/2021.

A.4 Gas and Electric Interconnection Costs

Similar to the 2018 PJM CONE Study, we identified representative gas pipeline lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project-specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs. We escalated the project-specific costs to 2021 dollars based on the assumed long-term inflation rate of 2.4% (see Table 8 above). We then calculated the average per-mile costs of the laterals ($5.1 million/mile) and the station costs ($4.1 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 40.[46]

[46] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

TABLE 40: GAS INTERCONNECTION COSTS

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(service year $m)*	Pipeline Cost *(2021$m)*	Pipeline Cost *(2021$m/mile)*	Meter Station *(Y/N)*	Station Cost *(service year $m)*	Station Cost *(2021$m)*
Panda Power Lateral Project	TX	2014	16	16.5	$26	$31	$2	Y	$2.2	$2.6
Woodbridge lateral	NJ	2015	20	2.4	$32	$37	$15	Y	$3.5	$4.0
Rock Springs Expansion	PA,MD	2016	20	11.0	$80	$90	$8	Y	$3.3	$3.7
Western Kentucky Lateral Project	KY	2016	24	22.5	$81	$91	$4	Y	$4.8	$5.4
UGI Sunbury Pipeline	PA	2017	20	35.0	$178	$196	$6	Y	n.a.	n.a.
Willis Lateral Project	TX	2020	24	19.0	$96	$98	$5	Y	$4.3	$4.4
Average							**$5.1**			**$4.0**

Sources and notes: A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

Table 41 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CC reference resources. The costs are based on confidential, project-specific cost data provided by PJM for both the direct connection facilities and all necessary network upgrades. In the case where plants chose to build their own direct connection facilities and did not report their costs to PJM, we calculated the capacity-weighted average of the units with direct connection costs and applied them to the units without direct connection costs. We escalated the direct connection and network upgrade costs from the online service dates to 2021 dollars based on the assumed long-term inflation rate of 2.9%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $18.9/kW for setting the electrical interconnection of the CC reference resource.

TABLE 41: ELECTRIC INTERCONNECTION COSTS IN PJM

Plant Size	Observations *(count)*	Electrical Interconnection Cost Capacity Weighted Average *(2021$m)*	*(2021$/kW)*
< 500 MW	5	$7.2	$18.3
500-750 MW	5	$12.2	$20.7
> 750 MW	7	$23.9	$18.3
Capacity Weighted Average	**17**	**$18.8**	**$18.9**

Source and notes: Confidential project-specific cost data provided by PJM.

A.5 Land Costs

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We collected all publicly-available land listings for counties within each CONE area. We then calculated the acre-weighted average land price for each CONE area and escalated 1 year using the long-term inflation rate of 2.2%. There is a wide range of prices within the same CONE Area as shown in Table 42.

TABLE 42: CURRENT LAND ASKING PRICES

CONE Area	Current Asking Prices		
	Observations *(count)*	Range *(2022$/acre)*	Land Price *(2022$/acre)*
1 EMAAC	7	$14,430 - $206,620	$96,361
2 SWMAAC	2	$13,148 - $42,785	$29,504
3 RTO	6	$9,867 - $37,429	$16,376
4 WMAAC	6	$22,49 - $68,14	$30,628

Sources and notes: We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

A.6 Property Taxes

Table 43 summarizes the calculations for the effective tax rates of each CONE area. We collected nominal tax rates, assessment ratios, and depreciation rates for counties of each CONE area. Using the nominal tax rates and assessment ratios, the effective tax rate for each CONE area was calculated by multiplying the average nominal tax rate and assessment ratio for counties within each CONE area state.

TABLE 43: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
		(%)	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%/yr)*
1 EMAAC								
New Jersey	[1]	4.0%	96.2%	3.8%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.7%	50.0%	1.3%	3.3%
3 RTO								
Ohio	[3]	5.5%	35.0%	1.9%	5.5%	24.0%	1.3%	See "SchC-NewProd (NG)" Annual Report
Pennsylvania	[4]	2.7%	100.0%	2.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.8%	99.0%	3.8%	n/a	n/a	n/a	n/a

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. For Gloucester County see:
https://tax1.co.monmouth.nj.us/cgi-bin/prc6.cgi?&ms_user=monm&passwd=data&srch_type=0&adv=0&out_type=0&district=0801
For Camden county see:
https://www.camdencounty.com/wp-content/uploads/2020/11/04CAMDEN.2021-Ratios.pdf
https://www.camdencounty.com/wp-content/uploads/2020/11/2021-County-Tax-Rates.pdf

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJ Rev Stat § 54:4-1 (2016).

[2a],[2c] Maryland tax rates estimated based on average county tax rates in Charles county and Prince George's county in 2017-2018. Data obtained from Maryland Department of Assessments & Taxation website:
https://dat.maryland.gov/Documents/statistics/Taxrates_2021.pdf

[2d] MD Tax-Prop Code § 7-237 (2016)

[2e] Phone conversation with representative at Charles County Treasury Department.

[3a],[3c] Ohio rates estimated based on the average effective tax rates from Trumbull and Carroll counties. For Trumbull county see:
http://auditor.co.trumbull.oh.us/pdfs/2020%20RATE%20OF%20TAXATION.pdf
For Caroll County see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202020.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 124 and 129:
http://www.tax.ohio.gov/Portals/0/communications/publications/annual_reports/2016AnnualReport/2016AnnualReport.pdf

[3e] Depreciation schedules for utility assets found in Form U-El by Ohio Department of Taxation:
http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2017/PUE_UEL.xls

[4a] Pennsylvania county tax rates for RTO based on the county of Lawrence, available at:
https://lawrencecountypa.gov/wp-content/uploads/2021/07/2021-millage.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1)* , only real estate tax assessed by local governments.

[5a] Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties:
https://www.luzernecounty.org/DocumentCenter/View/26403/2021-MILLAGES-JULY
https://www.lyco.org/Portals/1/Assessment/Documents/2021%20Millage.pdf?ver=2021-01-29-090920-517
https://bradfordcountypa.org/wp-content/uploads/2021/09/Bradford-County-Mill-Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note assessment ratios above 100% are capped at 100% in our calculations.

[5c]-[5e] According to Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1), only real estate tax assessed by local governments.

AUTHORS

J. Michael Hagerty brings experience in evaluating the costs and market value of new and existing generation resources across the U.S. and Canada. He has assisted wholesale market operators, including AESO, PJM, and ISO-NE, in analyzing the availability and costs of new entry of new renewable resources and natural gas power plants for developing key parameters in their markets. These projects included working closely with engineering consultants and stakeholders developing reference resource specifications and bottom-up cost estimates, developing enhanced approaches for calculating E&AS revenues projections, and estimating cost of capital for merchant generation plants. These projects have required extensive engagement with the client and stakeholders to develop well-supported parameters to capacity market demand curve and clearly present our analyses to stakeholders. He has also completed several policy-focused analyses of the future costs of renewable energy resources for U.S. state agencies, including Rhode Island, Nebraska, and Connecticut. Recently, he has assisted a major renewable energy developer in analyzing the value of solar resources in several states for developing community solar compensation mechanisms. Mr. Hagerty also has experience in wholesale market design, transmission planning and development, and strategic planning for utility companies.

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Dr. Samuel A. Newell is an economist and engineer with 23 years of experience consulting to the electricity industry. His expertise is in the design and analysis of wholesale electricity markets and in the evaluation of energy/environmental policies and investments, including in systems with large amounts of variable energy resources. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

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Johannes P. Pfeifenberger is an economist with a background in electrical engineering and over 25 years of experience in the areas of regulatory economics and finance. He has assisted clients in the formulation of business and regulatory strategy; submitted expert testimony to U.S. and European regulatory agencies, the U.S. Congress, courts, and arbitration panels; and provided support in mediation, arbitration, settlement, and stakeholder processes.

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Dr. Bin Zhou has over twenty years of consulting experience in consumer goods, energy, financial institutions, pharmaceutical and medical devices, technology, telecommunication, and utilities industries. He specializes in the application of financial economics, management accounting, business organizations, and taxation principles to a variety of consulting and litigation settings.

Dr. Zhou has supported testifying experts and led large engagement teams in many high-profile transfer pricing (Microsoft, Facebook, Coca-Cola, Boston Scientific / Guidant, Eaton, AstraZeneca, and GlaxoSmithKline), bankruptcy (Caesars, U.S. Steel Canada, Nortel, Ambac, and Enron), and securities litigations (MBIA, Parmalat, and Enron). His work has been primarily focused on the economic analysis of transfer pricing disputes involving hard-to-value intangibles, economic substance of complex transactions, solvency analysis and fraudulent conveyance claims, structured finance transactions, financial statement analyses, and damages. His most recent experience also includes economic profit analyses in anti-trust matters, a special litigation committee investigation of a large acquisition in the software industry, two international arbitration cases involving valuation of Korean publicly listed companies, two intellectual property transfers in distressed companies, and cost allocation of mutual fund advisory fees.

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Dr. Travis Carless specializes in low-carbon generation, nuclear power, climate policy analysis, and resource planning.

Prior to joining Brattle, Dr. Carless served as a President's Postdoctoral Fellow at Carnegie Mellon University and a Stanton Nuclear Security Fellow at the RAND Corporation. He received an NSF Graduate Research Fellowship for his research, which focused on assessing the environmental competitiveness of small modular reactors (SMRs) and risk and regulatory considerations for SMR emergency planning zones.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Samuel A. Newell**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

Samuel A. Newell

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **John M. Hagerty**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

____

John M. Hagerty

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Sang H. Gang**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

Sang H. Gang

Subscribed and sworn to before me, the undersigned notary public, this 28th day of September 2022.

OFFICIAL SEAL
BRENDA CAMPBELL
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:08/27/23

Brenda Campbell
Notary Public

Attachment E

Affidavit of
Samuel A. Newell, James A. Read Jr.,
and Sang H. Gang

UNITED STATES OF AMERICA
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.

INTRODUCTION

Qualifications

1. Our names are Samuel A. Newell, James A. Read Jr., and Sang H. Gang. Dr. Newell and Mr. Read are employed by The Brattle Group ("Brattle") as Principals. Mr. Gang is employed by Sargent & Lundy ("S&L") as a Principal Consultant. We are submitting this affidavit in support of PJM Interconnection, L.L.C.'s ("PJM") proposal to implement a forward-looking method for calculating energy and ancillary service ("EAS") net revenue offsets as part of PJM's Quadrennial Review of its Variable Resource Requirement ("VRR") curve used in clearing auctions in PJM's capacity market, known as the "Reliability Pricing Model" ("RPM"). The forward-looking offsets would replace the current historical offsets used in determining the net cost of new entry ("Net CONE") for the Reference Resource, to which prices along the VRR curve are indexed.

2. Dr. Newell is an economist and engineer with 24 years of experience consulting in wholesale electricity market design, wholesale market analysis, generation asset valuation, integrated resource planning, and transmission planning. He has led studies on Net CONE and VRR Curve adjustments for PJM's past Quadrennial/Triennial reviews and for ISO New England Inc. on the same and for Offer Review Trigger Prices. He has frequently used forward markets and forward-looking modeling as part of asset valuation assignments to support investment decisions by market participants. Prior to joining The Brattle Group in 2004, he was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at Kearney. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

3. Mr. Read is a financial and energy economist with more than 35 years of experience in valuation, risk management, and capital budgeting. Much of that experience has been in the energy industry, especially electric power and natural gas. He has worked with many companies on valuation and risk management assignments, including the development of forward price curves and the modeling and estimation of price volatility. He has also been a consulting expert in several high-profile litigation matters involving alleged manipulation of

electricity and natural gas markets. Mr. Read was the principal investigator on a series of studies for the Electric Power Research Institute to develop tools and methods for valuation and risk management, including development of the *Energy Book System* software. He is the author or coauthor of numerous publications on these and related topics. He earned an M.S. in Finance from the Massachusetts Institute of Technology and a B.A. in Economics from Princeton University.

4. Mr. Gang is an engineer with 14 years of experience in engineering design and consulting on a wide range of electric power projects including nuclear, gas, coal, biomass, wind, solar PV, and battery energy storage technologies. He has extensive experience assessing power plant technologies and estimating plant capital costs, operation and maintenance ("O&M") costs, and performance characteristics. In the last six years, Mr. Gang has been leading S&L's electric power resource planning projects, including evaluation of various generation and interconnection options. Mr. Gang also led the S&L team in working with Brattle to estimate the CONE for new merchant generation resources for PJM in its past Quadrennial Review and for the Alberta Electric System Operator in its development of a centralized capacity market in Alberta, Canada. Mr. Gang is a licensed Professional Engineer in the state of Illinois and earned a B.S. in Electrical Engineering from the University of Illinois at Urbana-Champaign.

5. Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes included as Exhibit No. 1 to our affidavit.

Scope of This Testimony

6. PJM requested our support in providing (1) an evaluation of the merits of a forward EAS instead of historical; (2) a method for producing a forward EAS offset consistent with commercial practices, including the sub-questions of estimating future market prices for electricity and fuel; (3) assumptions on certain operating parameters for new combined-cycle plants being proposed in this filing as the Reference Resource for the VRR curve; and (4) a method for using a virtual dispatch model to estimate the net EAS revenues, given electricity and fuel prices and resource characteristics. The proposed method will be used to determine Net CONE for the VRR curve in future RPM auctions, starting with the Base Residual Auction for the 2026/27 Delivery Year (less than two years forward), and for subsequent auctions on longer forward timeframes of up to 3.5 to 4.5 years ahead.

7. In this affidavit, we summarize our recommendations in Section II and provide the basis for our recommendations and additional details in Section III. We stop short of presenting resulting EAS Offsets, as PJM would do that when setting auction parameters prior to each Base Residual Auction.

SUMMARY OF RECOMMENDATIONS

The Merits of a Forward EAS Offset

8. The primary objective of the RPM is to maintain resource adequacy at competitive costs, and it does so through a downward-sloping VRR curve with a central point at a price equal to administratively estimated Net CONE when the quantity is approximately equal to the target reserve margin.[1] This helps support investment sufficient to achieve the target reserve margin through the following simple economic mechanism: if the reserve margin were below the target, capacity prices would rise above Net CONE and, in combination with net EAS revenues, should provide new entrants with an opportunity to earn their required return on and of capital whenever the reserve margin is below target (and not when above) and thus stimulate entry until the target is met.

9. To estimate a Net CONE that will achieve that effect, we start by estimating CONE as the all-in net revenue a resource would need in its first year to be willing to enter the market (given its capital and ongoing costs and a revenue outlook over its economic life). Net CONE subtracts from CONE the net revenues that an investor can expect to earn in the energy and ancillary services ("AS") markets in the first year. This offset is by its nature a forward-looking concept, and it has to be for the energy and capacity markets to complement each other in a way that meets resource adequacy objectives.

10. Yet PJM's current tariff specifies a backward-looking EAS, because of the following history: PJM originally adopted a backward-looking EAS Offset based on historical electricity and natural gas prices over the prior three years. This was an imperfect proxy but was thought to be unbiased on average over the long term, and the mechanics were straightforward relative to developing forward-looking estimates. Then in 2020, in connection with PJM's proposed Reserve Pricing Reforms, PJM adopted a forward-looking approach to calculating the EAS offset using a method we recommended—a method that exploits information in forward market prices for electricity and natural gas. FERC subsequently ordered PJM in December 2021 to revert to the historical method, however, as a collateral effect of rejecting part of PJM's proposed Reserve Pricing Reforms. PJM's forward-looking EAS approach was applied only in RPM Auctions for the 2022/2023 Delivery Year.

11. The backward-looking EAS approach could frustrate meeting RPM's objectives because it reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract. Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather or other conditions that distort the calculation and make it unduly volatile and not representative of expected future conditions. In addition, they can perpetuate undesirable disequilibrium conditions. For example, when supply has been scarce, the backward-looking EAS offset will tend to be high, which will reduce Net CONE and scale down the VRR curve. This will lead to buying less capacity just when it is needed.

[1] The quantity at Net CONE is not exactly at the target, but rather about 1% above target to avoid unacceptable shortfalls as supply and demand conditions fluctuate. This is discussed in our concurrent 2022 VRR Curve Report.

12. For these reasons, a historical EAS Offset is a poor substitute for a forward EA&S Offset that we have recommended in our past Quadrennial/Triennial reviews. We continue to recommend using forward prices to reflect the market conditions that developers face as they consider their investment decisions, following the method we present below. The merits are stronger now than ever in this volatile gas-price environment, where recent price spikes may differ substantially from expectations of the future. The merits are further heightened if adopting a combined cycle ("CC") as the Reference Resource for the VRR Curve—as we recommend in our 2022 CONE Report and as PJM is filing to do—since on-peak forward prices provide a good estimate of the market's expectations for CCs' revenues.

13. Some have suggested using an "equilibrium EAS" instead, as a way to prevent the disequilibrium perpetuation problems described above. The concept is to adjust the EAS offset to what they would be at the target reserve margin, as New York Independent System Operator and ISO New England Inc. attempt to do. This necessarily relies on energy market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices. For example, one might try to calibrate to forward prices to capture the expected effect of the full distribution of weather conditions, but then it is unclear what anticipated reserve margins are implicitly embedded in the forward prices. The inevitable ambiguity, controversy, and opacity may cause more trouble than it is worth. And a forward-looking EAS offset may accomplish nearly the same thing if forward-looking reserve margins tend to be mean-reverting, at least more so than the conditions of the recent past. Most importantly, the effects of any remaining slight differences from equilibrium reserve margins (if they were even observable) are likely to be minor compared to the effects of changing fuel markets, which a forward approach captures well.

14. For the same reasons that we recommend a forward-looking EAS offset for calculating the Net CONE parameter of the VRR curve, we also recommend forward EAS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, we understand that PJM only proposes changes to the VRR curve, and its inputs and parameters, and plans to address other applications of the EAS offset in a future proceeding. Nonetheless, even if a forward-looking approach is not implemented for Net ACR offer caps, we still recommend using a forward EAS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected EAS revenues.

Method for Developing a Forward EAS

15. To estimate expected net EAS revenues in the delivery year, we recommend that PJM adopt principles and methods that are consistent with commercial practices, as we would when supporting a client in an investment or contract decision for a similar timeframe. One of those principles is to rely on market prices to the extent they are observable. In this case, we recommend using forward prices for delivery of electric energy and natural gas to PJM market participants. Forward prices reflect expectations of market conditions at contract delivery dates and locations, and thus should incorporate assessments of the many factors that will determine prices at delivery, including such factors as fuel supply and demand, additions and retirements of generation and transmission capacity, and changes to market design.

16. We recommend applying forward price data where available to estimate resources' future net revenues in each zone, in three steps. These are the same steps recommended in our 2020 affidavit to support PJM's then-proposed transition to a forward EAS offset, but with some of the specifics updated.

17. Use available forward market data to derive monthly average future prices in each zone for peak and off-peak energy and for natural gas. Where reliable forward market data are unavailable, such as for energy losses differentials or monthly congestion price patterns between hubs and zones, rely on historical observations averaged over three years.

18. Shape the monthly prices into hourly (or daily) prices based on historical hourly (or daily) price patterns over three different historical years. The three "shape-years" are kept separate rather than averaged to reflect price volatility.

19. Finally, PJM uses these zonal hourly forward prices in its virtual dispatch model (which is referred to below as the "Projected EAS Dispatch" model) to simulate how each resource would be dispatched and settled in each shape-year, given its contemporaneous fuel costs and other operating characteristics. The resulting net EAS revenues from each shape-year are averaged together to produce a single forward-looking value consistent with the monthly forward prices for energy and natural gas.

Development of Forward Energy Prices

20. To best reflect market information, we recommend relying on electricity futures settlement prices from all PJM hubs with sufficient liquidity. In evaluating liquidity, we consider related products together with their product family (day-ahead peak, day-ahead off-peak, real-time peak, and real-time off-peak for a given location). 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.

21. Based on our analysis of futures traded at PJM hubs, we recommend that PJM rely on electricity futures settlement prices at PJM Western Hub, AEP-Dayton Hub, and Northern Illinois Hub ("NI Hub"). We do not recommend using zonal forwards at this time because they are not actively traded in the delivery year.

22. Each PJM zone is mapped to the hub with highest price correlations over the past three delivery years:

    a. NI Hub for COMED;

    b. AEP-Dayton Hub for AEP, ATSI, DAY, DEOK, DOM, DUQ, and EKPC; and

    c. Western Hub for all other zones.

23. We initially proposed similar mapping arrangements in our 2020 affidavit.[2] We repeated the analysis using the data from the most recent three-Delivery-Year (2019/20-2021/22) and found that the same mapping arrangements remain appropriate, except with DOM now mapped to AEP-Dayton Hub instead of Western Hub in the prior analysis.

24. We recommend using day-ahead futures settlement prices reported by Intercontinental Exchange ("ICE") at these trading hubs from the most recent 30 trading days.[3] Day-ahead futures prices and real-time futures prices are nearly the same, so choosing to rely on one versus the other will have little to no impact on the estimated EAS net revenues. Using day-ahead prices aligns with our approach to first develop monthly and hourly day-ahead prices consistent with the futures, and then apply historical hourly patterns of day-ahead and real-time prices to develop real-time prices. The use of a 30-day average of prices balances the benefit of the most recent market information with potential vulnerability to market manipulation from indexing to a single day. The prices from those 30 days can be averaged to yield the forward prices used for each hub, month, and on/off peak-period in the delivery year.

25. To calculate forward-looking *zone-specific* monthly peak and off-peak prices, PJM should apply available market information to account for future basis differentials between zones and their corresponding trading hubs. Future basis differentials can be informed by separately considering congestion and energy losses between the trading hub and each zone. To project congestion differentials a few years into the future, our standard practice is to use differences in congestion prices between each zone and the hub, from the latest long-term Financial Transmission Rights ("FTR") auction. The longest-term FTRs trade three years forward, about a year before the delivery period for the Base Residual Auction under the standard schedule. The long-term FTRs are a reasonable indicator of the market's expectations of congestion in the delivery year and will reflect shifting congestion patterns much more quickly than, for example, relying on historical congestion differentials from four to six years before the delivery year. Long-term FTR prices are, however, only annual (on-peak and off-peak) prices, not monthly. It is reasonable to shape these annual prices by month using the congestion component of monthly average day-ahead price differentials between the zone and relevant hub from the past three years.

26. For energy losses, we rely on historical losses at each zone scaled to futures prices. Historical losses in this case are sufficient because losses tend to be relatively small and more stable than energy prices, and there is no forward-looking, market-based source for directly estimating future losses.

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2 Compliance Filing of PJM Interconnection, L.L.C., Docket No. EL19-58-003, Attachment C ¶ 15 (Aug. 5, 2020).

3 Specifically, we recommend using the following futures products: for PJM Western Hub, PJM Western Hub Day-Ahead Peak Fixed Price Future and PJM Western Hub Day-Ahead Off-Peak Fixed Price Future; for AEP-Dayton Hub, PJM AEP-Dayton Hub Day-Ahead Peak Fixed Price Future and PJM AEP-Dayton Hub Day-Ahead Off-Peak Fixed Price Future; for NI Hub, PJM NI Hub Day-Ahead Peak Fixed Price Future and PJM NI Hub Day-Ahead Off-Peak Fixed Price Future.

27. The final step is to develop hourly day-ahead and real-time energy prices in each zone. To do so, we apply historical hourly patterns of zonal prices observed over the most recent three years to the observed forward prices of monthly peak and off-peak energy blocks. Historical price patterns provide the best information for the hourly shapes of day-ahead and real-time prices. We recommend using the price patterns from each of the three most recent years to capture random variation in price shapes from year to year. This approach will create three years of hourly prices that can be used separately to dispatch the resources.

28. Table 1 below shows the projected 2026/27 zonal all-hour day-ahead and real-time prices based on our recommended method, compared to historical average prices from DY 2019/20 to 2021/22. The projected prices are substantially higher than average historical prices, reflecting rising energy and natural gas prices in the forward market since Russia's invasion of Ukraine. This difference illustrates how poor a proxy historical prices can be for the market conditions market participants actually face when participating the forward capacity market. (Although the comparison shown here has one more year between the historical period and the delivery year than in PJM's typical schedule in which it sets auction parameters based on historical data, the price difference would be similar for the 2025/26 period, whose forecasts are close to the 2026/27 forecasts shown here.)

Table 1: Comparison of Historical and Forecasted All-Hour Average Zonal Energy Prices (nominal $/MWh)

		Day-Ahead		Real-Time	
Hub	Zone	DY 19/20-21/22 Average	DY 26/27 Forecasted	DY19/20-21/22 Average	DY 26/27 Forecasted
N. Illinois	COMED	$32.23	$42.11	$28.70	$41.88
AEP-Dayton	AEP	$37.36	$49.46	$33.05	$49.58
	ATSI	$37.23	$49.36	$32.59	$49.08
	DAY	$39.06	$51.91	$34.46	$51.72
	DEOK	$38.17	$51.02	$33.42	$50.52
	DOM	$41.78	$55.02	$37.28	$55.92
	DUQ	$36.70	$48.50	$32.24	$48.25
	EKPC	$37.63	$49.25	$33.13	$49.35
Western Hub	APS	$37.90	$52.17	$33.21	$52.18
	PEPCO	$41.13	$57.47	$36.02	$57.46
	BGE	$42.67	$59.92	$37.39	$59.91
	DPL	$35.53	$51.67	$32.37	$53.41
	PENELEC	$36.68	$50.91	$31.40	$50.02
	PPL	$34.19	$47.96	$29.73	$48.09
	METED	$37.05	$51.50	$32.13	$51.83
	PECO	$31.92	$45.54	$28.41	$45.99
	AECO	$32.14	$46.46	$28.60	$46.82
	PSEG	$33.65	$47.76	$30.09	$48.93
	JCPL	$33.02	$46.88	$29.19	$47.20
	RECO	$35.28	$49.38	$31.59	$50.88

Sources and Notes: Historical Delivery-Year (DY) 2019/20-DY 2021/22 prices from Hitachi Powergrids, Velocity Suite; forecasted 2026/27 prices are in 2026/27 nominal dollars based on the approach recommended herein. Forecasted prices are based on DY 2026 forwards in nominal dollars; zonal loss differentials applied as a percent of average monthly hub prices; and zonal congestion differentials from Year 3 results of the 2023/26 PJM Long-term FTR Auction. FTR results are escalated from 2025/26 to 2026/27 with a 2.2% long-term inflation rate from Blue Chip Economic Indicators and formed into monthly shapes using historical monthly congestion data.

Development of Forward Ancillary Services Prices

29. PJM's AS markets have historically been only about 5% as large as energy markets in terms of annual revenues,[4] and they have not provided a major source of additional revenues for most CCs. However, AS revenues have been significant for some resources and should be included in PJM's analysis of resources' net revenues.

30. There are no observable forward markets for AS. Lacking forward market prices, we have often projected AS prices by exploiting the fact that AS prices have historically been highly correlated with energy prices. The correlation arises because the primary cost of providing AS is the opportunity cost of forgone energy sales, as recognized in PJM's co-optimized energy-AS markets. The relationship appears to have been roughly linear, approximately passing through the origin. If the historical relationship can be expected to continue, one can project future AS prices by scaling historical hourly AS prices to the ratio of future energy prices to historical energy prices for the same hour.

Table 2: Comparison of Historical and Projected All-Hour Ancillary Service Prices (nominal $/MWh)

	DA Sync	RT Sync	DA Non-Sync	RT Non-Sync	RT RTO Regulation
Historical AS Prices					
2019/20	-	$1.22	-	$0.14	$14.56
2020/21	-	$2.37	-	$0.31	$15.23
2021/22	-	$5.30	-	$0.46	$36.10
Historical AS Prices Scaled with Forward Energy Prices in 2026/27 *(for Each Base Delivery Year)*					
2019/20	$1.99	$2.72	$0.14	$0.27	$32.96
2020/21	$4.26	$5.03	$0.45	$0.63	$32.09
2021/22	$4.34	$5.08	$0.31	$0.40	$36.25

Sources and Notes: Historical AS data provided by PJM; averages reported are unweighted across all hours of the delivery year. Future year shows three different base years because future EAS revenues are simulated three times (then averaged), once for each base year.

31. For Regulation (A), we determined that regulation revenues should not be included in the calculation because the market is too small at only 500–800 megawatts ("MW") (some of which is already absorbed by Battery Energy Storage System plants providing the premium Regulation (D) product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would exhaust that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would likely not change the Net CONE estimate. For Regulation (D), which has been the main source of revenue for battery storage resources in

[4] In 2021, the total revenues was $669 million for ancillary service products and $30,532 million for energy. *2021 State of the Market Report for PJM, Volume 2: Detailed Analysis*, Monitoring Analytics, LLC, 18 (Mar. 10, 2022), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf.

PJM, we understand that the unmet demand is extremely limited and so do not include Regulation (D) in the forward-looking analysis of EAS revenues.

32. Reactive reserves are cost-of-service based, not market-price based, but provide a small amount of additional revenue to all generators. We see no reason to change PJM's treatment in past determinations of Net CONE and MOPR offer floors.

Development of Forward Natural Gas Prices

33. We recommend developing forward-looking prices for natural gas in a manner analogous to our recommendations for electric energy. We start with the gas hubs that PJM assumes in its historical analysis of EAS revenues and use the open interest in these contracts as our indicator of liquidity. We determined that the gas hubs with sufficient liquidity include Chicago, Transco Zone 6 (non-NY), Dominion South, Michcon, TETCO M3, and Columbia-Appalachia TCO.

34. For zones a without a sufficiently pricing hub (hub with liquid forward products), we identify one of the six hubs with sufficient liquidity based on analysis of historical correlations:

    a. Transco Zone 5 maps to Transco Zone 6 (non-NY);

    b. Transco Zone 6 (NY) maps to TETCO M3; and

    c. Tennessee 500L maps to MichCon.

35. We then develop the monthly forward prices for these three hubs by scaling the forward price of the mapped hub by the average ratio of monthly prices at the illiquid hub and the mapped hub over the most recent three years.

36. Similar to the implementation steps for electricity futures, we recommend using a simple average of natural gas settlement prices for the most recent 30 trading days reported by ICE to balance the benefit of the most recent market information with potential vulnerability to market manipulation from indexing to a single day.

37. Monthly forward prices for natural gas can be shaped into daily prices by applying historical daily patterns of prices observed over each of the most recent three years, analogous to the method we recommend using to shape electricity prices. Daily gas prices are then assigned to each hour starting 10 a.m. each day, corresponding to the gas trading day.

Table 3: Comparison of Historical and Projected Daily Gas Spot Prices

Gas Hub	Zone	DY 19/20-21/22 Average	DY 26/27 Forecasted
Dominion South	APS, PENELEC	$2.55	$3.84
Chicago	COMED	$3.55	$4.97
Michcon	DAY, DEOK, ATSI	$2.99	$4.60
Transco Zone 6 (non NY)	AECO, BGE, DPL, JCPL	$3.00	$4.78
TETCO M3	DUQ, METED, PECO, PPL	$2.99	$5.01
TCO Basis	AEP	$2.74	$4.03
Transco Zone 5	DOM, PEPCO	$3.49	$5.91
Tennessee 500L	EKPC	$3.31	$4.98
Transco Z6 (NY)	PSEG, RECO	$3.11	$5.21

Sources and Notes: Historical DY 19/20- DY 21/22 Average based on historical daily spot price data downloaded from Hitachi Powergrids, Velocity Suite originally sourced from Enerfax; forecasted DY 26/27 prices based on approach recommended above.

Resource Cost and Operating Parameters

38. The 2022 CONE Study being submitted with this filing specifies all of the operating parameters needed to estimate the net EAS revenues for the Reference Resource. Table 4 below summarizes our recommendations at ISO conditions (*i.e.*, 59°, 60% relative humidity, and 14.7 psi at sea level), which is reasonable to use as a single average value for the EAS offset since PJM does not vary the characteristics over the course of the year in its virtual dispatch model.

Table 4: Recommended Values for CC Operating Parameters

Parameter	Value
Start Time *(minutes)*	120
Ramp Rates *(MW/min)*	30
Startup Costs	fuel only
Variable O&M Costs[5] *(2026 $/MWh)*	$1.31 major maintenance + $0.74 consumables
Full-Load Average Heat Rate *(MMBtu/MWh)*	6.537 including duct-firing

Simulation of Net Revenues

39. We recommend the same approach we often use in commercial applications when estimating market revenues consistent with forward prices: simulate the generation and settlement of resources against shaped, forward-looking day-ahead and real-time energy and AS prices. For

5 We escalated the major maintenance and consumables components of variable O&M cost estimates from January 2022 to June 2026 at inflation consistent with current CPI forecast from Blue Chip Indicators.

dispatchable resources, this is best done with an optimization model that, like PJM's actual market, puts each resource to its highest value use, recognizing each resource's capabilities, costs, and operating constraints. Unlike PJM's actual market, where prices are endogenous, this exercise takes future price forecasts as given and treats each generator as a price-taker. PJM is using an industry-standard simulation model called PLEXOS in its Projected EAS Dispatch. For nuclear, solar and wind resources, a fixed generation profile can be used with day-ahead prices to estimate net EAS revenues.

BASIS FOR RECOMMENDATIONS, AND ADDITIONAL DETAILS

The Use of Forward Market Prices

40. To estimate a resource's net EAS revenues during a future year, it is important to use forward-looking market prices of electricity and natural gas to account for evolving supply and demand conditions, including changes in market design. Forward market prices are inherently forward looking. They anticipate market conditions at forward contract delivery dates. To understand why this is true, consider the terms of a "plain-vanilla" forward contract.

41. A plain-vanilla forward contract is an agreement to exchange a fixed quantity of a commodity for a fixed price on a specified future date. The contract terms, including the price, quantity, delivery date, and delivery place, are set in advance of delivery, at the time the contract is executed. If at the delivery date the value of the commodity is greater than the forward contract price, then the buyer will gain by receiving a commodity that is worth more than the price paid, and the seller will lose by delivering a commodity that is worth more than the price received. On the other hand, if the value of the commodity is less than the forward contract price at delivery, then the buyer will lose and the seller will gain. Buyer and seller are on opposite sides of the contract, so what one gains the other loses, and vice versa.

42. When viewed in isolation, a forward contract is like a bet on the future value of the underlying commodity. If "bets" placed by entering into forward contracts reliably yielded profits, then trading would soon dry up, since the other side of those bets would reliably realize losses. The incentives on both sides of the forward market to bet correctly—that is, for speculative trades, whether long or short, to be based on all relevant and available information—are clear. This implies that forward market prices will anticipate market prices at contract delivery dates, including all of the factors that could influence future, uncertain supply and demand.

43. Note that some forward contracts specify financial settlement against a specified price index or other reference price rather than exchange of cash for the physical commodity itself. This does not change the essential informational properties of the forward contract prices.

44. Futures contracts are a particular type of forward contract. The feature of futures contracts that distinguishes them from plain-vanilla forwards is that futures are marked to market and resettled on a daily basis, so that market participants realize contract gains and losses along the way rather than all at once on the contract delivery date. To enable daily resettlement, exchanges that list futures contracts must determine a settlement price for each contract on each business day. One of the byproducts of this futures market design is that the sponsoring exchange makes its futures settlement prices public. In contrast, prices determined in over-the-counter trading of energy contracts are generally not publicly available.

45. Futures exchanges also report on a daily basis the open interest for each contract they list. Open interest refers to the number of contracts that are "open" (that is, remain outstanding) at the end of the trading day. This reflects the cumulative number of contracts that have been opened but not yet closed out or offset. Margin requirements for futures market participants are regularly adjusted to reflect the mark-to-market gains and losses that are calculated based on exchange settlement prices. Thus, even if no new trades take place on a given day, money is changing hands to rebalance margin accounts in light of changes in futures settlement prices.

46. 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.

47. In recommending the use of forward energy prices to forecast net EAS revenues, we urge PJM to be sensitive to the alignment of forward price observation dates and forward contract delivery dates for power, natural gas, and other relevant fuel commodities. The price of natural gas in particular is one of the principal drivers of electric energy prices. Therefore, forward electricity prices on any given date will reflect forward natural gas prices on that same date, not forward gas prices set well before or after that date. Alignment of price observations will be essential to avoid systematic errors in forecasts of EAS margins. Consistency across commodities is similarly important when shaping future prices into hourly and daily patterns.

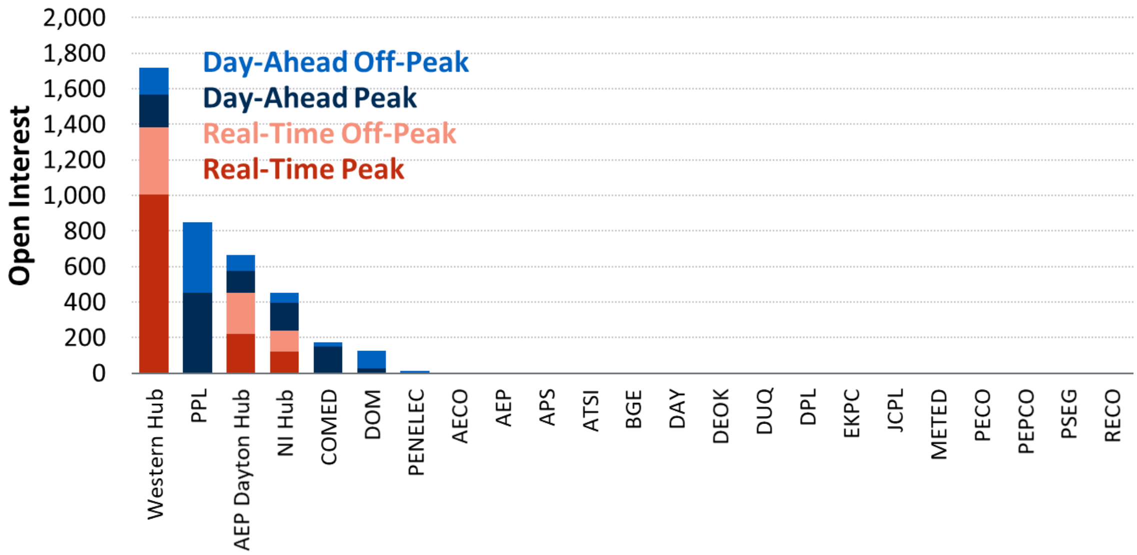
Development of Forward Energy Prices

Hub Prices

48. We reviewed open interest for the electricity futures at each of the trading hubs and transmission zones in PJM for which ICE lists futures contracts. We also checked open interest on electricity contracts traded on NYMEX platforms but found it was more limited than open interest on the ICE. We noted, however, that settlement prices are closely aligned across these electronic trading platforms. Finally, we reviewed settlement prices for long-dated day-ahead and real-time futures contracts and found that the prices are nearly identical. For that reason, we considered the aggregate level of activity to inform the level of liquidity.

49. Based on the open interest on closely related futures products at each of the trading hubs and zones shown in Figure 1, we conclude that only the Western Hub, AEP-Dayton Hub, and NI Hub futures are currently sufficiently liquid 3.5 to 4.5 years forward for PJM to rely on in its forward-looking EAS analysis. At other trading hubs corresponding to PJM's zones, open interest is much more limited and inconsistent from year to year. Although Figure 1 shows that open interest at PPL in 2026 is greater than at AEP-Dayton Hub and NI Hub, this relationship does not hold in other years. The limited liquidity of zonal futures makes them more vulnerable to manipulation (although that may be mitigated by using 30 days of forward prices instead of a single day).

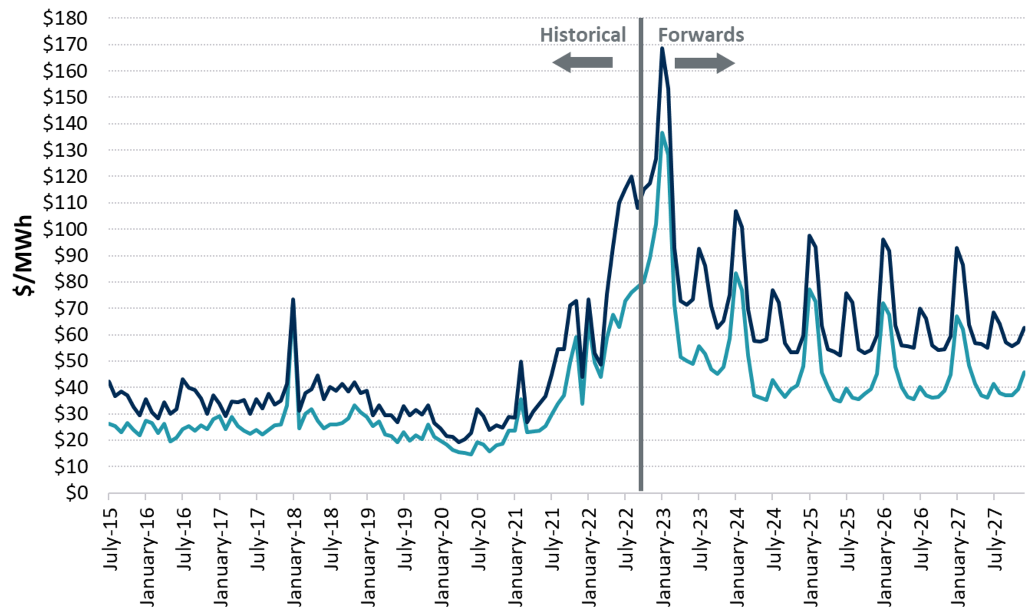
Figure 1: Monthly Average Open Interest for PJM Futures Products at Trading Hubs and Zones for Delivery Year 2026/27



Source: Open interest reported by ICE for 9/9/2022. Data provided by Bloomberg.

50. Figure 2 below shows the Western Hub historical and futures prices for day-ahead peak and off-peak energy from 2015 to 2028.

Figure 2: Average Western Hub Peak and Off—Peak Futures Settlement Prices over 30 Trade Dates Ending September 1, 2022



Sources and Notes: 30-trade-day average of settlement prices reported by ICE. Data provided by Bloomberg. Monthly average historical energy prices from Hitachi Powergrids, Velocity Suite for 2015–2022.

51. To map each PJM zone to one of these three hubs, we analyzed the correlation of historical prices between the three electricity hubs and the 20 PJM zones, using monthly average peak and off-peak data for DY 19/20–DY 21/22. Table 6 below shows that the results of our analysis align with intuition: for each zone, the hub with highest price correlation is that which is geographically closest. We tested the correlations for both peak and off-peak prices and found that the correlations are unchanged.

Table 5: Hub-to-Zone LMP Correlation Analysis

Mapped Hub	Zone	Correlation	Mapped Hub	Zone	Correlation
N. Illinois	COMED	1.00	Western Hub	APS	1.00
				PEPCO	1.00
				BGE	0.99
AEP-Dayton	AEP	1.00		DPL	0.93
	ATSI	1.00		PENELEC	0.99
	DAY	1.00		PPL	0.99
	DEOK	1.00		METED	0.99
	DOM	0.98		PECO	0.96
	DUQ	1.00		AECO	0.96
	EKPC	1.00		PSEG	0.95
				JCPL	0.97
				RECO	0.94

Source: Analysis of monthly average historical energy prices from Hitachi Powergrids, Velocity Suite for DY 19/20 – DY 21/22.

Basis Differentials

52. To develop a zone-specific forward price for each month, it is necessary to apply a basis adjustment to the corresponding hub price, reflecting expected congestion and losses between the zone and the hub. We evaluated whether to rely on historical congestion data or the congestion implied by long-term FTR prices between each zone and its trading hub.[6] Long-term FTRs provide forward-looking, market-based information on the expected level of congestion between each zone and its relevant trading hub for the next three years. The long-term FTR auctions are centralized, multilateral, and locational-based markets, producing nodal clearing prices. Similar to PJM's nodal energy market, every price is determined by bids from many market participants for source-sink pairs across the PJM system (rather than isolated markets for each source-sink pair) combined with transmission constraints. The Independent Market Monitor found the FTR market to be competitive in its 2021 State of the Market Report

6 We also considered the use of zone-specific futures but dismissed that approach due to limited liquidity for those products, as shown in Figure 1.

and determined that the ownership of FTR obligations is "unconcentrated for the individual years of the 2021/2024 Long Term FTR Auction."[7]

53. We analyzed how well historical long-term FTR prices align with realized congestion in the day-ahead market between the trading hubs and zones during the same delivery years for 2011/12 to 2021/22. Of course, long-term FTRs may not correctly predict realized congestion in the delivery year because there is substantial uncertainty about the market conditions they serve to hedge. However, FTR prices do incorporate predictable changes, such as the reverse in congestion from the historical west-to-east direction when Marcellus shale gas production endowed certain zones with the lowest-cost gas. Using FTR prices to forecast basis differentials can incorporate such changes sooner than trailing historical prices.

54. Energy losses must also be added to the congestion implied by FTRs to yield the total basis differential between the hub and each zone. We recommend using the historical monthly average differential of the losses component of LMPs between the hub and zone and scaling that value by the ratio of forward to historical hub prices. This approach is reasonable because losses tend to be relatively stable over time, and there is no independent forecast of congestion losses across the relevant source-sink pairs.

55. Hourly day-ahead prices for use in the virtual dispatch model are derived by scaling the historical hourly day-ahead prices for the three sample years by the ratio of the monthly day-ahead peak/off-peak futures prices to the historical monthly average day-ahead peak or off-peak prices relevant for each hour. Similarly, hourly real-time prices for use in the dispatch model are developed by scaling historical hourly real-time prices from the three historical sample years by the same ratio as for developing hourly day-ahead prices (*i.e.*, monthly day-ahead peak/off-peak futures divided by the historical monthly average day-ahead peak or off-peak prices relevant for each hour). Using day-ahead prices to scale historical real-time prices will allow average monthly real-time prices to be higher or lower than average monthly day-ahead prices, reflecting the day-ahead and real-time price pattern in the energy market.

Development of Forward Ancillary Services Prices

56. As discussed above, because there are no observable forward markets for AS, we propose scaling historical AS prices to the ratio of forward to historical energy prices, exploiting the linear relationship between prices of synchronized and non-synchronized reserves to energy prices.

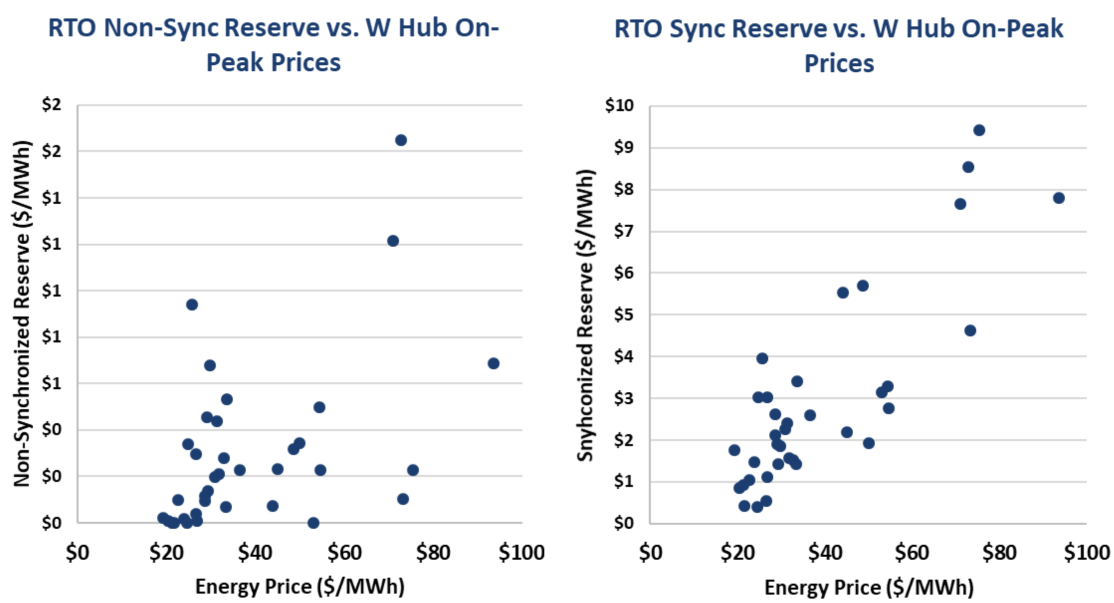
57. Figure 3 below shows the relationship between energy prices on the x-axis and both synchronized ("Sync") and non-synchronized ("Non-Sync") reserves on the y-axis.[8] For synchronized reserves, historical prices have had an approximately linear relationship to energy prices, nearly through the origin. This suggests it is reasonable to forecast future hourly

[7] *2021 State of the Market Report for PJM, Volume 2: Detailed Analysis*, Monitoring Analytics, LLC, 680 (Mar. 10, 2022), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf.

[8] The Regulation market clearing price is the sum of Regulation Capability price and Regulation Performance price.

AS prices by multiplying historical AS prices by the ratio of forward to historical energy prices, at least when operating within a given price formation regime, before or after the Reserve Pricing Reforms.

Figure 3: Correlation of Ancillary Service to Energy Prices, 2019-2022



Source: Historical ancillary services prices from public PJM data; historical energy prices from Hitachi Powergrids, Velocity Suite for DY 19/20 – DY 21/22.

58. The historical relationship of non-synchronized reserves prices and energy prices is neither strong nor particularly linear. However, scaling with energy will ensure consistency with other products and properly reflect the cascading relationship among product prices, where lower-value non-synchronized reserves are always priced at or below synchronized reserves. This assumption will not materially affect resources' net EAS revenues since non-synchronized reserve prices should be low in any case.

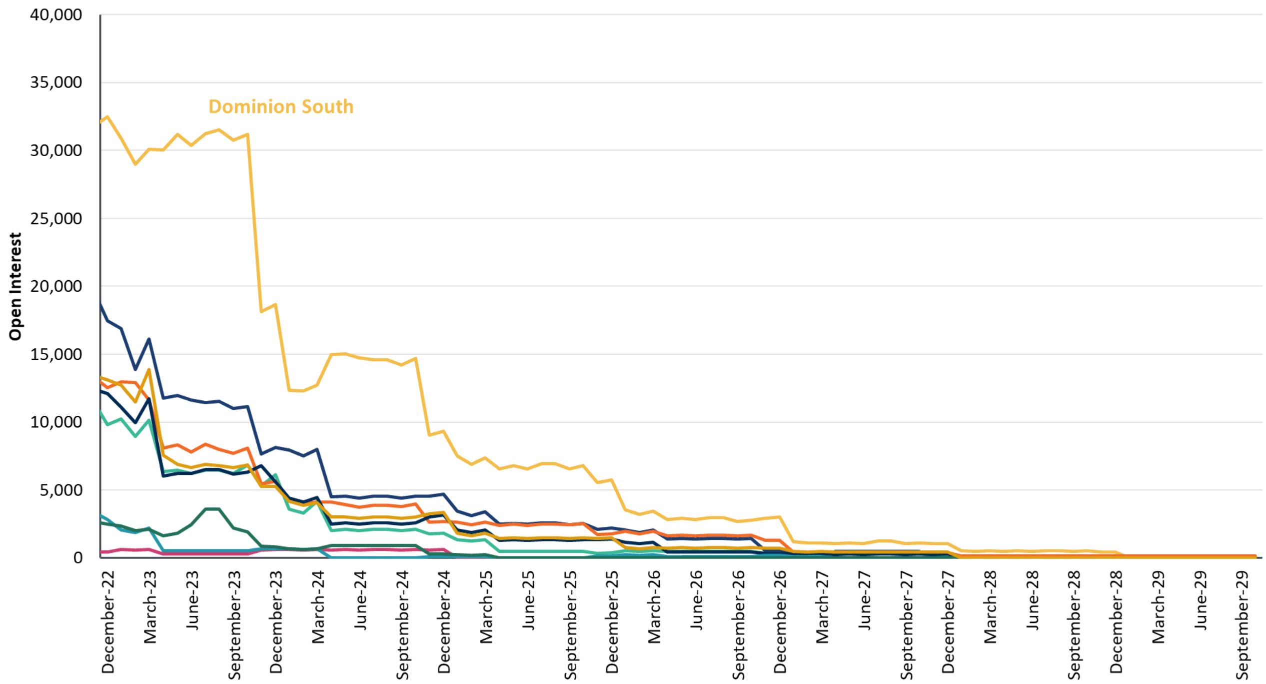
59. PJM has historically modeled two reserve pricing areas, MidAtlantic-Dominion and Rest-of-RTO, reflecting historical flow and constraint patterns, although we understand from PJM that there has been little price separation between the areas in recent years. For simplicity, we recommend using a single RTO-wide price. It is reasonable to use historical Rest-of-RTO AS prices in all zones, and scale them to changes in energy prices at Western Hub.

Development of Forward Natural Gas Prices

60. For its prior historically-based EAS net revenues analyses, PJM mapped each zone to one of nine natural gas trading hubs. We examined the liquidity of gas futures at each of these hubs by reviewing open interest on the ICE. Based on this review, we identified six hubs with futures that are sufficiently liquid in the 3.5 to 4.5 year forward timeframe, as shown in Figure 4 below (and this pattern has been consistent over the past few trading years). These liquid hubs include Dominion South, Chicago, Michcon, Transco Zone 6 non-NY, Columbia-Appalachia TCO, and TETCO M3, which collectively span much of PJM's geographic footprint. The remaining

three gas hubs (Transco Zone 5, Transco Zone 6 NY, and Tennessee 500L) had futures with limited open interest in the necessary forward timeframe, and open interest that has varied over the past several trading years (for a given forward timeframe). The liquidity of these hubs could change over time with changes in market conditions, and PJM should evaluate the choices of hubs during its next Quadrennial Review to continue to ensure that the most liquid hubs are used.

Figure 4: Open Interest at PJM Gas Hubs Through 2029



Source: Open interest reported by ICE for 9/9/2022. Data provided by Bloomberg.

61. Prices at the three less liquid hubs should not be used to derive RPM auction parameters because the limited liquidity makes the prices less reliable and more susceptible to manipulation if the prices were used to set RPM auction parameters. Prices there can instead be linked to the more liquid hubs nearby. To identify the most appropriate liquid hub for each illiquid hub, we analyzed hub-to-hub correlations in historical prices during DY 2019/20-2021/22. Based on these correlations, Tennessee 500L is now mapped to MichCon and Transco Z6 (NY) is mapped to TETCO M3. In our 2020 affidavit, these hubs were mapped to Columbia-Appalachia TCO and Transco C6 (non-NY), respectively. The EKPC zone is mapped to Tennessee 500L and PSEG and RECO zones are mapped to Transco Z6 (NY), so their mapping changes as well. The current mapping is shown in Table 7.

Table 6: Mapping between Illiquid Gas Hubs and Liquid Gas Hubs

Gas Hub	Mapped Gas Hub	DY 19/20-21/22 Correlation
Transco Zone 5	Transco Zone 6 (non NY)	0.990
Tennessee 500L	MichCon	0.845
Transco Z6 (NY)	TETCO M3	0.995

Source: Historical DY 19/20 –DY 21/22 correlation based on historical monthly spot price data downloaded from Hitachi Powergrids, Velocity Suite originally sourced from Enerfax.

62. Absent available market-based information about future expectations of the basis from the liquid hub to the illiquid one, we recommend applying a historical basis adjustment reflecting the DY 19/20–DY 21/22 average in each month to yield the forecasted gas price. The adjustment is small since the liquid hubs themselves span most of PJM's footprint and provide good proxies for the less liquid hubs, as demonstrated by high historical price correlations.

Key Inputs on Unit Operating Parameters

63. Our basis for the CC's physical operating parameters are as follows:

    a. **Start Time.** The 120-minute start time is based on proprietary start-up curve information from GE and previous S&L experience with start-up of advanced H-class class turbines. The start time identified assumes a warm start, with purge credit, and ramping of the combustion turbines ("CT") to minimum emission compliant load before loading the steam turbine ("rapid response lite" start).

    b. **Rates.** The 30 MW/min ramp rate for the GE 7HA.02 CC is based on reported values from operators bidding into the PJM AS markets, even though GE's published ramp rate for the 7HA.02 in a 1x1 combined-cycle arrangement is 60 MW/min according to GE's website.[9]

    c. **Power Augmentation**. Each CT in the CC arrangement is assumed to include evaporative cooling on the combustion air intake. Evaporative coolers increase the air mass flow rate through the CT compressor resulting in higher turbine output and efficiency. This technology contributes to the equipment capital costs and presents a marginal operational cost increase associated with variable water usage.

    d. **Cooling Technology**. The CC units are assumed to use dry air-cooled condensers ("ACCs") for their steam cycle process cooling. Use of ACC technology in lieu of "wet" mechanical draft cooling towers dramatically reduces the water usage of a CC facility at the expense of a higher capital cost for the equipment, and a small toll upon the unit heat rate and net capacity.

64. This concludes our affidavit.

[9] *See 7HA Gas Turbine 7HA*, GE Gas Power, https://www.ge.com/power/gas/gas-turbines/7ha (last visited Sept. 21, 2022).

Exhibit No. 1

Samuel A. Newell,
James A. Read Jr.,
and Sang H. Gang
Qualifications

Samuel Newell

PRINCIPAL

Boston | +1.617.234.5725 | Sam.Newell@brattle.com

Dr. Newell leads Brattle's Electricity Group of over 50 consultants addressing the most challenging economic questions facing an industry transforming to clean energy.

His expertise centers on electricity wholesale markets, market design, generation asset valuation, integrated resource planning, and transmission planning. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Electricity Litigation & Regulatory Disputes

EDUCATION

- **Massachusetts Institute of Technology**
  PhD in Technology Management and Policy
- **Stanford University**
  MS in Materials Science and Engineering
- **Harvard University**
  AB in Chemistry and Physics

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2004–Present)**
  Principal
- **Cambridge Energy Research Associates (2003–2004)**
  Director
- **Kearney (1998–2002)**
  Manager

CAPACITY MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **PJM's Capacity Market Reviews and Parameters**. For PJM, conducted all five official reviews of its Reliability Pricing Model (2008, 2011, 2014, 2018, and 2022). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE) parameter, and the methodology for estimating net energy and ancillary services revenues. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. Relatedly, have also provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources, for use in the Minimum Offer Price Rule. Submitted testimonies before FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at FERC.
- **Buyer Market Power Mitigation in PJM**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Resource Accreditation**. Co-authored two whitepapers in 2022 for the Massachusetts Attorney General's Office on resource accreditation methodologies, including "ELCC" and empirical methods; evaluated reform options for New England.
- **ISO-NE Capacity Demand Curve Design.** For ISO New England (ISO-NE), developed a demand curve for its Forward Capacity Market. Solicited staff and stakeholder input, then established market design objectives. Provided a range of candidate curves and evaluated them against objectives, showing tradeoffs between reliability uncertainty and price volatility (using a probabilistic locational capacity market simulation model we developed). Worked with Sargent & Lundy to estimate the Net Cost of New Entry to which the demand curve prices are indexed. Submitted testimonies before FERC, which accepted the proposed curve.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO-NE, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity Market. Worked with Sargent & Lundy to conduct bottom-up analyses of the costs of constructing and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable, given

their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, reducing installed capacity requirements) for capacity costs and prices, emergency procurement costs, and energy prices. Whitepaper submitted by ISO-NE to the FERC.
- **New York State Resource Adequacy Constructs**. For NYSERDA, evaluated the customer cost impacts of several alternative constructs that differ in whether FERC or the state sets the rules and how buyer-side mitigation is implemented.
- **Evaluation of Moving to a Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a 4-year forward capacity market. Evaluated options based on stakeholder interviews and the experience of PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs. Recommendations were used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- **MISO Resource Adequacy Framework for a Transforming Fleet**. Currently advising MISO in its Resource Availability and Need initiative (2020-present) to reform its resource adequacy framework to address year-round shortage risks as the fleet transforms. Presenting to stakeholders on resource accreditation, determination of LSE requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before FERC.
- **MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.

- **Singapore Capacity Market Development**. For the Energy Market Authority (EMA) in Singapore, developed a complete forward capacity market design in 2018-2021. Worked with EMA in collaboration with other government entities and stakeholders. Published high-level design documents and presented to stakeholders. Currently assisting with detailed design and implementation.
- **Western Australia Capacity Market Design**. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design and implementation of a new forward capacity market. Reviewed the high-level forward capacity market design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; helped define administrative processes needed to conduct the auction and the governance of such processes.
- **Western Australia Reserve Capacity Mechanism**. For EnerNOC, evaluated Western Australia's administrative Reserve Capacity Mechanism in comparison with international capacity markets, and made recommendations for improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other senior government officials.

ENERGY & ANCILLARY SERVICES (AND OTHER) MARKET DESIGN (ORGANIZED BY JURISDICTION)

- **ERCOT Post-Uri Market Reform**. Advised ERCOT and the Public Utility Commission of Texas regarding market design for reliability. Interviewed Commissioners, ERCOT, and stakeholders. Helped frame the problem as primarily resource adequacy and secondarily as operational reliability; evaluated market design proposals to support resource adequacy; evaluated refinements to the Operating Reserve Demand Curve and to Ancillary Services markets; presented recommendations and commented on stakeholder proposals at numerous PUCT workshops. Later invited by the State Energy Plan Advisory Committee to testify.
- **ERCOT's Proposed Future Ancillary Services Design**. For the Electric Reliability Council of Texas (ERCOT), evaluated the benefits of its proposal to unbundle ancillary services, enable broader participation by load resources and new technologies, and tune its procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load resources, and new technologies could participate. Directed their simulation of the market using PLEXOS, and evaluated other benefits outside of the model.
- **Investment Incentives in ERCOT**. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy; and (3) evaluate options to enhance resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability.

Conclusions informed a PUCT proceeding in which I filed comments and presented at several workshops.

- **Operating Reserve Demand Curve (ORDC) in ERCOT**. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted backcast analyses using interval-level data provided by ERCOT and assuming generators rationally modify their commitment and dispatch in response to higher prices under the ORDC. Analysis was used by ERCOT and the PUCT to inform selection of final ORDC parameters.
- **Economically Optimal Reserve Margins in ERCOT**. For ERCOT, co-led studies (2014 and 2018) estimating the economically-optimal reserve margin, and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load-shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- **Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals.** Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **IESO's Market Renewal Program / Energy Market Settlements**. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for the new day-ahead and real-time nodal market, including make-whole payments for natural gas-fired combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- **Forward Energy and Ancillary Services (EA&S) Revenues in PJM**. For PJM, developed a method for using forward prices to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters. Collaborated with Sargent &

Lundy to establish resource characteristics, and with PJM staff to conduct hourly virtual dispatch. Filed successful testimony with FERC.

- **Energy Price Formation in PJM**. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with FERC, and which FERC largely accepted and cited in its April 2019 Order.
- **Energy Market Monitoring & Market Power Mitigation**. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- **Market Design for Energy Security in ISO-NE**. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to the NEPOOL Markets Committee.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **Market Development Vision for MISO**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2–5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **RTO Accommodation of Retail Access**. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.
- **LMP Impacts on Contracts**. For a California state agency, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Estimated congestion costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using a third party's GE-MAPS market simulations (and helped

to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- **Australian Electricity Market Operator (AEMO) Redesign**. Advised AEMO on market design reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives; interviewed stakeholders; assessed local market characteristics affecting the design; synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The Public Utilities Office posted our whitepaper in support of its conclusions.

TRANSMISSION PLANNING AND MODELING

- **Initial Report on the New York Power Grid Study**. With NYSERDA, NYDPS, and Pterra, submitted a report to the NYPSC projecting New York's transmission needs to support its long-term clean energy goals under the Climate Leadership and Community Protection Act. Our work synthesized findings from three sub-reports addressing local T&D needs, offshore wind, and overall bulk system needs.
- **Value of a NY Public Policy Transmission Project**. On behalf of NY Transco LLC, submitted testimony in 2020 regarding the economic benefits of Transco's proposed "Segment B" transmission project. Critiqued an opposing expert's production cost analysis and broader benefit-cost analysis.
- **Benefit-Cost Analysis of New York AC Transmission Upgrades**. For the New York Department of Public Service (DPS) and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability between Upstate and Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift the location of future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. DPS used our analysis to inform its recommendation to the NY Public Service Commission to declare a "Public Policy Need" to build a project such as the best ones identified.
- **Evaluation of New York Transmission Projects**. For the New York Department of Public Service (DPS), provided a cost-benefit analysis for the "TOTS" transmission projects.

Showed net production cost and capacity resource cost savings exceeding the project costs, and the lines were approved. The work involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.

- **Economic and Environmental Evaluation of New Transmission to Quebec**. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- **Benefit-Cost Analysis of a Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the energy market impacts using the PROMOD model.
- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.
- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.
- **Analysis of Transmission Constraints and Solutions**. Performed a multi-client study identifying major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions. Worked with transmission engineers from client organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several economic major transmission projects.
- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle evaluation of commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and other models. Intensively tested each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability to calibrate models with backcasts using actual RTO data.

ENERGY POLICY ANALYSIS

- **Life Extension for Diablo Canyon**. For an environmental organization in CA in 2022, evaluated the net benefits of extending the operating life of the Diablo Canyon Nuclear Power Plant. Calibrated the base case in Brattle's gridSIM capacity expansion model to existing studies sponsored by CA state agencies, and estimated the impacts of retaining Diablo Canyon in terms of emissions, fixed and variable costs, and ability to meet both reliability objectives and clean energy goals.
- **Tariffs on PVs**. For a renewable energy advocacy group in 2022, evaluated the impacts of potential anti-circumvention tariffs that the Department of Commerce was considering imposing on PVs from four countries. Our team developed a trade model to estimate the impact on market prices for panels in the US; then leveraged our gridSIM capacity expansion model to estimate the impact on utility-scale investments, emissions, and energy prices/costs; then incorporated into a macroeconomic model to estimate effects on jobs and GDP.

- **Renewable Energy Tax Policy Impacts**. For ACORE, a renewable energy advocacy group, evaluated alternative proposals to extend and expand tax credits in 2021. Simulated investment, costs, prices and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model. Informed client's policy position.
- **Clean Energy Transformation**. For NYISO, led a team to project how the fleet may evolve to meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used gridSIM to model investment and operations subject to constraints on reliability and clean energy. Evaluated technology needs for meeting load during extended periods of low wind/solar. Study results helped inform questions about future market design and reliability.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad group of stakeholders opposing the rule in a filing before FERC, evaluated DOE's proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply; the likely cost of the rule; and the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.

GENERATION AND STORAGE ASSET VALUATION, AND PROCUREMENTS

- **Value of Flexibility in ERCOT**. For a large company evaluating a range of investment strategies, assessed the value of flexibility in ERCOT today and in the future as wind and solar penetration increases. Used Brattle's GridSIM model to project investments and retirements over the next 10 years. Analyzed the likely increase in demand for ancillary services. Simulated system operations accounting for short-term uncertainty in net load forecasts, using ENELYTIX PSO to model day-ahead and real-time operations.
- **Storage Development Company Due Diligence**. For an international investor consider an equity investment in a storage development company in ERCOT, reviewed the developer's business model, interviewed the developer, and compared their revenue projections to our own.
- **Storage Asset Development in New York**. For a renewable generation company considering developing large new storage assets in New York City and Long Island, provided a market analysis, including a 20-year estimate of net revenues. Used Brattle's GridSIM model to simulate investment, operations, prices, and revenues over that timeframe, after calibrating the model to current actual prices.
- **Valuation of a Gas-Fired Combined-Cycle Plant in ERCOT**. For a generation company, estimated net revenues for an existing plant, using Brattle's GridSIM model to project investment/retirement, operations, prices, and revenues over that timeperiod, after calibrating the model to recent prices. Assessed market risks.
- **Evaluation of Hydropower Procurement Options**. For a potential buyer of new transmission and hydropower from Quebec, evaluated costs and emissions benefits

under a range of contracting approaches. Accounted for the possibility of resource shuffling and backfill of emissions. Considered the value of storage services.

- **Valuation of a Gas-Fired Combined-Cycle Plant in New England**. For a party to litigation, submitted testimony on the fair market value of the plant. Simulated energy and capacity markets to forecast net revenues, and estimated exposure to capacity performance penalties. Compared the valuation to the transaction prices of similar plants and analyzed the differences. Collaborated with a co-testifying export on project finance to assess whether the estimated value would suffice to cover the plant's debt and certain other obligations.
- **Valuation of a Portfolio of Combined-Cycle Plants across the U.S.** For a debt holder in a portfolio of plants, estimated the fair market value of each plant in 2018 and the plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our own models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuation analyses across a range of scenarios. Provided insights into market and regulatory drivers and how they may evolve.
- **Wholesale Market Value of Storage in PJM**. For a potential investor in battery storage, estimated the energy, ancillary services, and capacity market revenues their technology could earn in PJM. Reviewed PJM's market participation rules for storage. Forecast capacity market revenues and the risk of performance penalties. Developed a real-time energy and ancillary service bidding algorithm that the asset owner could employ to nearly optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- **Valuation of a Generation Portfolio in ERCOT**. For the owners of a portfolios of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over a range of plausible scenarios. Analyzed the effects load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how future changes in these drivers could cause the value to shift over time.
- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially

on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.

- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a revenue forecast for energy and capacity. Evaluated the implications of several scenarios around key uncertainties.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net

energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

INTEGRATED RESOURCE PLANNING (IRP)

- **Resource Planning in Hawaii**. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- **IRP in Connecticut (for 2008, 2009, 2010, 2012, and 2014 Plans)**. For two major utilities and the state Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive IRPs. Plans involved projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, REC markets, and suppliers' likely investment/retirement decisions. Addressed electricity supply risks, natural gas supply into New England, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.
- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and

facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

DEMAND RESPONSE (DR) MARKET PARTICIPATION, MARKET POTENTIAL, AND MARKET IMPACT

- **Demand Response (DR) Integration in MISO**. Through a series of assignments, helped MISO incorporate DR into its energy market and resource adequacy construct, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers; (2) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets. Identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; (3) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying the practices of other RTOs and by characterizing the DR resources within the MISO footprint.
- **Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity.** For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Compensation Options for DR in ISO-NE's Energy Market**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **ERCOT DR Potential Study**. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the potential for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- **Wholesale Market Impacts of Price-Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic

retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.

- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Value of DR Investments**. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

GAS-ELECTRIC COORDINATION

- **Gas Pipeline Investment for Electricity.** For the Maine Office of Public Advocate, co-sponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other experts' reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- **Gas Pipeline Investment for Electricity.** For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- **Fuel Adequacy and Other Winter Reliability Challenges**. For an ISO, co-authored a report assessing the risks of winter reliability events due to inadequate fuel, inadequate weatherization, and other factors affecting resource availability in the winter. Evaluated solutions being pursued by other ISOs. Proposed changes to resource adequacy requirements and energy market design to mitigate the risks.
- **Gas-Electric Reliability Challenges in the Midcontinent**. For MISO, provided a PowerPoint report assessing future gas-electric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.

RTO PARTICIPATION AND CONFIGURATION

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on (1) MISO and PJM's real-time inter-RTO coordination process, and (2) the economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO's and PJM's energy prices and shadow prices on reciprocal coordinated flow gates.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

ENERGY LITIGATION

- **Enforcement Matter in ISO-NE's Day-Ahead Load Response Program**. Provided expert testimony on behalf of the FERC Office of Enforcement in "Fed. Energy Regulatory Comm'n v. Silkman" in the U.S. District Court of Maine regarding allegations that defendant "engag[ed] in a fraudulent scheme to manipulate the ISO New England, Inc. (ISO-NE) Day-Ahead Load Response Program" by gaming the baseline and claiming false reductions in load. Submitted initial and rebuttal reports analyzing whether defendant's conduct was consistent with industry practice and the purpose of demand response. Matter settled.
- **Valuation of Alleged Misrepresentations of Demand Response Company.** Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony before the American Arbitration Association (non-public).
- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice

charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's costs and operating characteristics. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

TARIFF AND RATE DESIGN

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

BUSINESS STRATEGY

- **Preparing a Gentailer for a Transformed Wholesale Market Design.** Supported a gentailer in Alberta to prepare its generation and retail businesses for the implementation of a capacity market.
- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility, evaluated a venture to build and operate cogeneration facilities. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Helped draft RFPs and develop negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance its trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the value client could bring to each customer. Worked with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a utility, performed a market assessment for DG technologies by segment in the U.S.
- **Fuel Cells**. For a fuel cell manufacturer, provided electricity market analysis to inform a market entry strategy in the U.S.

ARTICLES & PUBLICATIONS

- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 1: Foundation of Resource Accreditation, report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).

- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 2: Options for New England report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).
- *Offshore Wind Transmission: An Analysis of Options for New York*, report prepared for Anbaric, August 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- *Singapore Forward Capacity Market—FCM Design Proposal (third Consultation Paper)*, prepared for the Singapore Energy Market Authority, May 2020 (with J. Chang and W. Graf). Followed draft proposals in first and second Consultation papers in May 2019 and Dec 2019.
- *Quantitative Analysis of Resource Adequacy Structures*, report prepared for NYSERDA and NYSDPS, July 1, 2020 (with K. Spees, J. Imon Pedtke, and M. Tracy). Update to version from May 29, 2020.
- New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040 Including Alternative Scenarios, report prepared for NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Crocker Ross, and J. Moraski). Update to version from May 18, 2020.
- *Qualitative Analysis of Resource Adequacy Structures for New York*, report prepared for NYSERDA and NYSDPS, May 19, 2020 (with K. Spees and J. Imon Pedtke).
- *Offshore Transmission in New England: The Benefits of a Better-Planned Grid*, report prepared for Anbaric, May 2020 (with J. Pfeifenberger and W. Graf).
- *Implementing Recommended Improvements to Market Power Mitigation in the WEM*, report prepared for Energy Policy WA in Western Australia, April 2020 (with T. Brown).
- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, report prepared for PJM, March 17, 2020 (with M. Hagerty, S. Sergici, E. Cohen, S. Gang, J. Wroble, and P. Daou).
- "Forward Clean Energy Markets: A New Solution to State-RTO Conflicts," *Utility Dive*, January 27, 2020 (with K. Spees and J. Pfeifenberger.)
- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes: Expanded Report Including a Detailed Market Design Proposal, report prepared for NRG, September 2019 (with K. Spees, W. Graf, and E. Shorin).
- *International Review of Demand Response Mechanisms in Wholesale Markets*, report for the Australian Energy Market Commission, June 2019 (with T. Brown, K. Spees, and C. Wang).

- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes, report prepared for NRG, April 2019 (with K. Spees, W. Graf, and E. Shorin).
- *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, Final Draft*, prepared for the Electric Reliability Council of Texas, December 20, 2018 (with R. Carroll, A. Kaluzhny, K. Spees, K. Carden, N. Wintermantel, and A. Krasny).
- Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively, discussion paper, July 2018 (with K. Spees, J. Pfeifenberger, and J. Chang).
- *Fourth Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 16, 2018 (with J. Pfeifenberger, K. Spees, and others).
- *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Michael Hagerty, J. Pfeifenberger, S. Gang of Sargent & Lundy, and others).
- *Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule*, whitepaper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel).
- *Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions*, report prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, D.L. Oates, T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke).
- *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals*, whitepaper prepared for the New York Independent System Operator, August 11, 2017 (with R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee).
- "How wholesale power markets and state environmental Policies can work together," *Utility Dive*, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees).
- *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, whitepaper prepared for the Public Utilities Office in the Government of W. Australia's Department of Finance, September 1, 2016 (with T. Brown, W. Graf, J. Reitzes, H. Trewn, and K. Van Horn).
- *Western Australia's Transition to a Competitive Capacity Auction*, report prepared for Enernoc, January 29, 2016 (with K. Spees and C. McIntyre).

- *Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal*," report prepared for ERCOT, December 2015 (with R. Carroll, P. Ruiz, and W. Gorman).
- Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint—Options for MISO, Utilities, and States, report prepared for NRG, November 9, 2015 (with K. Spees and R. Lueken).
- *International Review of Demand Response Mechanisms*, report prepared for Australian Energy Market Commission, October 2015 (with T. Brown, K. Spees, and D.L. Oates).
- Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism, report prepared for EnerNOC, Inc., August 2014 (with K. Spees).
- *Third Triennial Review of PJM's Variable Resource Requirement Curve*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).
- *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*, report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pfeifenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).
- *Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).
- *Estimating the Economically Optimal Reserve Margin in ERCOT*, report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees, and I. Karkatsouli).
- "Capacity Markets: Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy*. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger and K. Spees).
- *ERCOT Investment Incentives and Resource Adequacy*, report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).
- "Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" *Public Utilities Fortnightly*, December 2011 (with J. Pfeifenberger).
- Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15, prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees).

- *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).
- "Fostering economic demand response in the Midwest ISO," *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).
- "DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.
- Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements, report prepared for MISO, January 2010 (with K. Spees and A. Hajos).
- Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design, report prepared for MISO, January 2010 (with A. Hajos).
- *Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market*, whitepaper for the NYISO and stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).
- *Fostering Economic Demand Response in the Midwest ISO*, whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).
- *Review of PJM's Reliability Pricing Model (RPM)*, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).
- "Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).
- Enhancing Midwest ISO's Market Rules to Advance Demand Response, report written for MISO, March 12, 2008 (with R. Earle).
- "The Power of Five Percent," *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).
- Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).
- *Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets*, Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).
- "Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).

- *Quantifying Demand Response Benefits in PJM*, study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).
- "Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).
- "Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Observations and Implications of the 2021 Texas Freeze," presented to Power Markets Today webinar on the February 2021 ERCOT electricity failure, April 14, 2021.
- "Offshore Wind Transmission: An Analysis of Options for New York," presented at LCV Virtual Policy Forum, August 6, 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- "Possible Paths Forward from MOPR," presented to Power Markets Today webinar on "Capacity Market Alternatives for States," July 15, 2020.
- "Considerations for Meeting Sub-Annual Needs, and Resource Accreditation across RTOs," presented to MISO Resource Adequacy Subcommittee, July 8, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "New York's Evolution to a Zero Emission Power System—Modeling Operations and Investment through 2040 Including Alternative Scenarios," presented to NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Ross, and J. Moraski).
- "Singapore Foreward Capacity Market Design—Industry Briefing Sessions," presented via video to Singapore electricity market stakeholders, June 5&9, 2020 (with W. Graf).
- "Industry Changes in Resource Adequacy Requirements," presented to MISO Resource Adequacy Subcommittee, May 6, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," presented to NYISO Stakeholders, March 30, 2020 (with R. Lueken, J. Weiss, J. Moraski, and S. Ross).
- "Electricity Market Designs to Achieve and Accommodate Deep Decarbonization," presented to Advanced Energy Economy (AEE) video conference, "ISO-NE in 2050: Getting To An Advanced Energy Future In New England," March 18, 2020.

- “U.S. Offshore Wind Generation, Grid Constraints, and Transmission Needs,” presented at Offshore Wind Transmission, USA Conference, September 18, 2019 (with J. Pfeifenberger and K. Spokas).
- “Pollution Pricing in the Power Sector: Market-Friendly Tools for Incorporating Public Policy,” presented to GCPA Spring Conference, Houston, TX, April 16, 2019.
- “The Transformation of the Power Sector to Clean Energy: Economic and Reliability Challenges,” keynote address to the Power Engineers 4th Annual Power Symposium, Weehawken, NJ, April 4, 2019.
- “Market Design for Winter Energy Security in New England: Further Discussion of Options,” presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).
- “Market Design for Winter Energy Security in New England: Discussion of Options,” presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, January 9, 2019 (with D.L. Oates).
- “Market Equilibrium Reserve Margin in ERCOT,” presented to Power Markets Today webinar, “A Post Summer Check-in of ERCOT’s Market,” October 31, 2018.
- “Carbon Pricing in NYISO’s Wholesale Energy Market, and Applicability to Multi-State RTO markets,” presented to Raab Policy Roundtable, May 23, 2018; presented to the Energy Bar Association, 2018 EBA Energizer: Pricing Carbon in Energy Markets, June 5, 2018; presented to Bank of America Merrill Lynch, June 25, 2018.
- “Reconciling Resilience Services with Current Market Design,” presented to RFF/R-Street Conference on “Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System,” Washington, D.C., May 30, 2018.
- “System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches,” presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.
- “Natural Gas Reliability: Understanding Fact from Fiction,” panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).
- “Carbon Pricing in Wholesale Markets: Takeaways from NYISO Carbon Charge Study,” presented to Harvard Electric Policy Group, October 12, 2017.

- "Pricing Carbon into NYISO's Wholesale Energy Market: Study Overview and Summary of Findings," presented to NYISO Business Issues Committee, September 12, 2017.
- "Carbon Adders in Wholesale Power Markets—Preventing Leakage," panelist at Resources for the Future's workshop on carbon pricing in wholesale markets, Washington, D.C., August 2, 2017.
- "Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.
- "ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.
- "The Future of Wholesale Electricity Market Design," presented to Energy Bar Association 2016 Annual Meeting & Conference, Washington, DC, June 8, 2016.
- "Performance Initiatives and Fuel Assurance—What Price Mitigation?" presented to Northeast Energy Summit 2015 Panel Discussion, Boston, MA, October 27, 2015.
- "PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).
- "Energy and Capacity Market Designs: Incentives to Invest and Perform," presented to EUCI Conference, Cambridge, MA, September 1, 2015.
- "Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.
- Before the Arizona Corporation Commission, Commission Workshop on Integrated Resource Planning, Docket No. E-00000V-13-0070, presented "Perspectives on the IRP Process: How to get the most out of IRP through a collaborative process, broad consideration of resource strategies and uncertainties, and validation or improvement through market solicitations," Phoenix, AZ, February 26, 2015.
- "Resource Adequacy in Western Australia—Alternatives to the Reserve Capacity Mechanism (RCM)," presented to The Australian Institute of Energy, Perth, WA, October 9, 2014.
- "Customer Participation in the Market," panelist on demand response at Gulf Coast Power Association Fall Conference, Austin, TX, September 30, 2014.

- “Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy,” presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.
- “EPA’s Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d),” presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.
- “Capacity Markets: Lessons for New England from the First Decade,” presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.
- “The State of Things: Resource Adequacy in ERCOT,” presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.
- “Resource Adequacy in ERCOT,” presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.
- “Electricity Supply Risks and Opportunities by Region,” presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.
- “Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response,” presented to the Cadwalader Energy Investor Conference, New York, NY, February 7, 2013 (with K. Spees).
- “The Resource Adequacy Challenge in ERCOT,” presented to The Texas Public Policy Foundation’s 11th Annual Policy Orientation for legislators, Austin, TX, January 11, 2013.
- “Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives,” presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.
- “Resource Adequacy in ERCOT,” presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.
- “Texas Resource Adequacy,” presented to Power Across Texas, Austin, TX, September 21, 2012.
- “Resource Adequacy and Demand Response in ERCOT,” presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.
- “Summary of Brattle’s Study on ‘ERCOT Investment Incentives and Resource Adequacy’,” presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

- “Market-Based Approaches to Achieving Resource Adequacy,” presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.
- “Fundamentals of Western Markets: Panel Discussion,” WSPP’s Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with J. Weiss).
- “Integrated Resource Planning in Restructured States,” presentation at EUCI conference on “Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes,” White Plains, NY, October 17, 2011.
- “Demand Response Gets Market Prices: Now What?” NRRI teleseminar panelist, June 9, 2011.
- Before the PJM Board of Directors and senior level representatives at PJM’s General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.
- “Resource Adequacy in New England: Interactions with RPS and RGGI,” Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.
- “Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns,” Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.
- “Evaluating the Economic Benefits of Transmission Investments,” EUCI’s Cost-Effective Transmission Technology Conference, Nashville, TN, May 3, 2007 (with J. Pfeifenberger, presenter).
- “Quantifying Demand Response Benefits in PJM,” PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.
- “Who Will Pay for Transmission,” CERA Expert Interview, Cambridge, MA, January 15, 2004.
- “Reliability Lessons from the Blackout; Transmission Needs in the Southwest,” presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.
- “Application of the ‘Beneficiary Pays’ Concept,” presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

JAMES A. READ, JR.

Principal

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James Read is a financial and energy economist with particular expertise in valuation, risk management, and capital budgeting. Many of his engagements have been in or related to the electric power, natural gas, and petroleum industries.

Mr. Read has served as a consulting and testifying expert in litigation and regulatory matters involving energy trading, valuation, cost of capital, capital structure, commercial damages, securities, and taxes. His management consulting has involved valuation and optimization of energy production, storage, and transmission assets; pricing wholesale and retail energy contracts; analysis, modeling, and forecasting energy market prices and volatility; and hedging retail electric and gas service obligations. In addition, he has developed analytical methods and software tools for valuation and risk management of energy contracts and portfolios. He has also developed and taught professional training courses on these topics.

Prior to joining The Brattle Group, Mr. Read was a Principal with Incentives Research Inc., and before that Director of Financial Consulting with Charles River Associates. He holds a B.A. in economics from Princeton University and an M.S. in finance from the Massachusetts Institute of Technology.

PRACTICE AREAS

- Electric Power
- Oil, Gas & Commodities
- Securities
- Tax & Restructuring
- Valuation

SELECTED EXPERIENCE

Management Consulting

- Mr. Read is working with a large municipal power company to evaluate alternatives for redeployment of a coal-fired power plant. Options under consideration include conversion to burn natural gas, mothballing, and retirement.
- Conducted independent reviews of risk management policies, procedures, and compliance for several electric power companies in the United States and Canada.

- Advised many companies regarding portfolio risk assessment and management, including forward price curve building, volatility modeling and estimation, valuation of energy contracts and assets, calculation of risk exposures, and measurement of portfolio risk.
- Working with a wholesale generating company to optimize operation and bidding of its pumped storage hydro resources in ISO markets.
- Advising the owner of a natural gas-fired combined-cycle power plant whether to refurbish or retire the plant.
- Analyzed historical data on availability and outages of power generating units to develop a model for describing and forecasting generation fleet reliability.
- Worked with a major electric utility to develop custom analytics and software for measuring the risk of its power supply portfolio. This was used for regulatory reporting as well as internal management purposes.
- Advised several clients in the electric utility industry in connection with the design, pricing, and risk management of "provider of last resort" and similar retail transition services created as part of industry restructuring.
- Advised many clients in connection with the valuation of power generation assets for purchase or sale. Projects entailed development and use of options-based valuation tools as well as estimation of long-term forward price curves and volatility term structures.
- Developed economic theory for allocating capital to lines of business in multiple-line insurance companies.
- Developed a derivatives-based methodology for estimating the cost of capital for investments in merchant power generation.
- Designed methodology for pricing a new product in the gas pipeline industry that would allow shippers to purchase options on pipeline capacity expansion.
- Developed a valuation algorithm for a retail electric service that allows the supplier to buy back electric energy when wholesale market conditions are tight.
- Advised Tennessee Valley Authority and other companies in connection with their evaluations of bids received in response to power purchase option RFPs. Engagements involved development of models for evaluating option-type bids and development of forward price and volatility curves.
- In a study for the U.S. Department of Energy, estimated the cost of capital for investments in petroleum inventories. This was part of a research effort to determine the effectiveness of government policies aimed at stimulating private stockpile formation.

Studies for Electric Power Research Institute (EPRI)

- Directed development of the *Energy Book System* (EBS) software for valuation and management of energy resources. EBS includes tools for portfolio risk management, valuation and pricing of wholesale and retail energy contracts, and valuation and management of generation resources.
- Developed and taught professional training courses on the application of option pricing and related principles and methods for understanding the value and risk of commodity contracts and physical assets. Courses include *Value & Risk in Energy Markets*, *Applied Valuation & Risk Management*, and *Generation Asset Valuation*.
- Developed an options-based valuation and decision-making model of nuclear power plants. The model explicitly incorporates the option to retire prior to license expiration and the option to extend the operating license.
- Principal author of the *Utility Capital Budgeting Notebook*, which integrates previous EPRI studies in finance and project evaluation into a single text.
- Prepared an exposition of how the theory and methods of option pricing can be exploited to value real assets, investment projects, and nonfinancial contracts.
- Developed a methodology for selecting project-specific discount rates. The methodology is based on the idea that cash flows can be partitioned into risk classes, and hence that the value of an investment project can be found by adding up the values of the parts.
- Identified a conceptual problem that arises in applications of the revenue requirements method when utility capital recovery procedures are inflexible. The study pointed out that feedback between demand and utility rates may undermine the logic for cost-based project evaluation.
- Developed a rigorous procedure for calculating the cost of holding fuel and other commodity inventories. The procedure exploits information in commodity futures and money markets.
- Developed theoretical and empirical analyses of a bias that exists in conventional measures of market risk when applied to public utility companies. This study explained why a bias is likely to arise, provided empirical confirmation of the bias, and devised corrected measures of market risk.
- Prepared an exposition of the revenue requirements method. Among other findings, the report concluded that the appropriate risk-adjusted discount rates for calculating the present value of revenue requirements may differ from the discount rates used to calculate net present value. It also identified the conceptual errors involved in the use of “customer” discount rates.

Litigation and Regulatory Support

- Mr. Read prepared an expert report in a derivative matter involving the sale of NGL pipelines owned by an MLP to the general partner (GP). The dispute centered on whether the consideration provided by the GP, which included redemption of some LP and GP units and a waiver of cash distributions under its IDRs, was commensurate with the value of the pipelines.
- Prepared an expert report in a matter involving the breach of a long-term supply contract for materials used in the development of oil and gas reserves by hydraulic fracturing.
- Mr. Read is advising legal counsel in connection with an internal investigation of the foreign exchange sales and trading practices of a major financial institution.
- Advised legal counsel in several matters involving allegations of manipulation of electricity, natural gas and petroleum markets in the United States.
- Advised counsel regarding energy trading and risk management practices in an arbitration between participants in a major energy marketing and trading joint venture.
- In a dispute between the NYMEX and the Intercontinental Exchange (ICE), prepared an expert report on the determination of settlement prices for natural gas and crude oil futures contracts.
- Prepared an expert report on the cost of capital acquired through the merger of a public company with a special purpose acquisition company (SPAC). The merger involved a complex exchange of warrants and shares.
- Advised counsel to the former owner of a metals mining business who was contesting an EPA finding as to another party's ability to pay for hazardous waste clean-up. This was in connection with Superfund sites for which the parties had joint and several liability.
- In a federal tax matter, Mr. Read was an expert witness on the economic substance of foreign exchange transactions ostensibly facilitated by a credit agreement with a major financial institution.
- Served as a consulting expert in an international arbitration matter involving a joint venture (JV) to market beverages in Central America. The dispute centered on the terms and implementation of an option held by one of the JV parties to buy certain assets from the other.
- Consulting expert in an international arbitration concerning the valuation of large-scale undeveloped mineral reserves located in Central Asia.
- Served as a consulting expert in several tax disputes regarding tax shelters that utilized combinations of exotic options and other OTC derivatives.

- Consulting expert in an international arbitration matter involving the valuation of petroleum assets expropriated by Venezuela.
- Served as a consulting expert in a number of litigation matters that involved option backdating. This included assessing the odds that options were backdated as well as valuing executive and employee stock options.
- Provided legal counsel with economic analysis of a series of structured finance transactions in a litigation matter involving companies in the energy and insurance industries.
- Advised legal counsel in an arbitration that concerned the termination value of power supply contracts written under the WSPP master agreement.
- On behalf of an industry trade group, conducted a preliminary investigation of whether certain commodity futures prices had been manipulated.
- Analyzed gaming practices in the Western power markets during the energy crisis of 2000-2001. Prepared expert testimony for hearings before the Federal Energy Regulatory Commission.
- Assisted in the development of expert testimony in connection with regulatory hearings about the sale of a nuclear power station by a public utility to an unregulated energy company.
- Analyzed the impact of credit risk on the pricing of energy contracts. Analysis was performed in the context of a regulatory review of energy procurement decisions.
- Used option pricing methods to estimate the premium over cost required to compensate investors for the long-term nature of investments in railroad assets. Analysis was used in a revenue adequacy proceeding before the Surface Transportation Board.
- In a matter before the Iran-U.S. Claims Tribunal, worked with an academic expert in finance to develop testimony concerning the value of expropriated oil fields in the Persian Gulf.
- In MCI v. AT&T, worked with an academic expert in finance to critique and prepare rebuttal testimony regarding the damages model proffered by experts for the plaintiff.
- In U.S. v. IBM, critiqued testimony regarding the risk and profitability of IBM. The evidence submitted in this case included analyses of accounting and market data.
- In proceedings under the Regional Rail Reorganization Act, worked with academic experts in finance to prepare testimony concerning the value of the Penn Central Intercity Freight Lines.

Other Experience

- Financial Analyst, Corporate Financial Staff, General Motors Corporation. Mr. Read worked in forward product programs and corporate transfer pricing.
- Staff Economist, Mail Classification Research Division, United States Postal Service. Mr. Read's responsibilities included writing statements of work, technical evaluation of analytical study proposals, and directing contractors in the Long Range Classification Research Program.
- Staff Economist, Office of Rates, United States Postal Service. Mr. Read was engaged in the preparation of testimony filed with the Postal Rate Commission in support of requests for changes in rates. His responsibilities included cost analysis, revenue forecasting, econometric analysis of demand, and rate design.

PUBLICATIONS & WORKING PAPERS

"Real Options and Hidden Leverage" (with Stewart C. Myers), *Journal of Applied Corporate Finance*, Winter 2022.

"Risk Capital: Theory and Applications" (with Stewart C. Myers and Isil Erel), *Journal of Applied Corporate Finance*, Winter 2021.

"Real Options, Taxes and Financial Leverage" (with Stewart C. Myers), *Critical Finance Review*, 2020.

"Oil and Gas Termination Payments: Devil is In the Details" (with R. Goldberg), *Law360*, April 26, 2016.

"A Theory of Risk Capital" (with Stewart C. Myers and Isil Erel), *Journal of Financial Economics*, December 2015.

"Hedge Timing" (with R. Goldberg), *Public Utilities Fortnightly*, May 2012.

Advances in Volatility Modeling for Energy Markets (with R. Goldberg), EPRI, Palo Alto: December 2011. TR-1021812.

"Smart Power and Evolution of Risk Management" (with R. Goldberg and P. Fox-Penner), *Electric Light & Power*, December 2010.

"Just Lucky? A Statistical Test for Option Backdating" (with R. Goldberg), Social Science Research Network (SSRN), March 2007. Available at SSRN: http://ssrn.com/abstract=1411190.

Delta Hedging Energy Portfolios (with R. Goldberg), EPRI 1010686, Palo Alto: Electric Power Research Institute, 2005.

Resource Planning and Procurement in Evolving Electricity Markets (with F. Graves and J. Wharton), prepared for Edison Electric Institute, January 2004.

Retail Risk Management: A Primer (with R. Goldberg), EPRI 1002225, Palo Alto: Electric Power Research Institute, 2003.

Analytic Approximations for Generation Option Values (with R. Goldberg), EPRI 1002209, Palo Alto: Electric Power Research Institute, 2003.

Portfolio Optimization: Concepts and Challenges, EPRI 1001567, Palo Alto: Electric Power Research Institute, 2002.

"Capital Allocation for Insurance Companies" (with Stewart C. Myers), *Journal of Risk and Insurance*, December 2001. (Selected by Casualty Actuarial Society as most valuable paper published by American Risk and Insurance Association in 2001. Winner of Robert C. Witt Research Award for outstanding feature article in the *Journal of Risk and Insurance* in 2001.)

Optimization and Valuation of Natural Gas Storage (with R. Goldberg), EPRI 1005947, Palo Alto: Electric Power Research Institute, 2001.

Describing Commodity Prices in the Energy Book System (with R. Goldberg), EPRI 1001170, Palo Alto: Electric Power Research Institute, 2000.

"Energy Derivatives and Price Risk Management" (with A. Altman and R. Goldberg), in *Pricing in Competitive Electricity Markets,* A. Faruqui and K. Eakin (eds.), Kluwer Academic Publishers, 2000.

Residual Obligations Following Electric Utility Restructuring (with F. Graves), Edison Electric Institute, May 2000.

"Dealing With a Price Spike World" (with R. Goldberg), *Energy & Power Risk*, May 2000.

Valuation and Management of Nuclear Assets, EPRI TR 107541, Palo Alto: Electric Power Research Institute, 1998.

"Capacity Prices in a Competitive Power Market" (with F. Graves), in *The Virtual Utility*, Kluwer Academic Publishers, 1997.

Option Pricing for Project Evaluation: An Introduction, EPRI TR-104755, Palo Alto: Electric Power Research Institute, 1995.

The Utility Capital Budgeting Notebook (with others), EPRI TR-104369, Palo Alto: Electric Power Research Institute, 1994.

"It's All Downstream From Here" (with S. Thomas), *Energy Risk*, June 1994.

"Analysis for Changing Minds" (with S. Thomas), *Energy Risk*, April 1994.

Project-Specific Discount Rates, report prepared for Electric Power Research Institute, 1992.

"Rates of Return that Include New Gas Industry Risks," *Natural Gas*, November 1989.

"Estimating the Cost of Switching Rights on Natural Gas Pipelines" (with F. Graves and P. Carpenter), *Energy Journal*, October 1989.

Holding Costs for Fuel Inventories, EPRI P-6184, Palo Alto: Electric Power Research Institute, 1989.

"Option Pricing: A New Approach to Mine Valuation" (with S. Palm and N. Pearson), in *Selected Readings in Mineral Economics,* Pergamon Press, 1987.

Capital Budgeting for Utilities: The Revenue Requirements Method, EPRI EA-4879, Palo Alto: Electric Power Research Institute, 1986.

"Determining the Cost of Capital for Utility Investments" (with A.L. Kolbe and R. Lincoln), in *Energy Markets in the Longer Term: Planning Under Uncertainty*, Ed. A.S. Kydes and D.M. Geraghty, Elsevier Science Publishers, 1985.

The Cost of Capital: Estimating the Rate of Return for Public Utilities (with A.L. Kolbe and G. Hall), Cambridge: MIT Press, 1984.

Rate Shock and Power Plant Phase-Ins (with A.L. Kolbe), Charles River Associates, Washington, DC: Edison Electric Institute, 1984.

Critique of Conventional Betas as Risk Indicators for Electric Utilities (with A.L. Kolbe), EPRI EA-3392, Palo Alto: Electric Power Research Institute, 1984.

PRESENTATIONS

"Natural Gas Price Forecasts", presented to EPRI Fuels, Power Markets and Resource Planning Conference, Washington, D.C., November 2-3, 2016.

"Valuation of Wind Power", presented to *Wind Power Development Tutorial*, Infocast, San Diego, July 9-10, 2009.

"Wind Power: Economic & Technology Risk", presented to *Renewable Energy M&A Summit*, Infocast, Washington, D.C., April 15, 2009.

"Techniques for Valuation of Wind Generation", presented to *Wind Power Development Tutorial*, Infocast, San Francisco, July 29-30, 2008.

"Using Volatility in Valuation & Risk Management", presented to *Gas Volatility*, Infocast, Houston, September 22-24, 2003.

"Fundamentals of Portfolio Risk Management" (with R. Goldberg), Tutorial presented to *Portfolio Optimization*, Infocast, Houston, November 14-16, 2001.

"Retail Transition Services in Electric Utility Restructuring," Presentation to Illinois Energy Leadership, Chicago, October 29-30, 2001.

"Provider of Last Resort: Retrospect & Prospect," Presentation to Staff Subcommittee on Accounting and Finance, National Association of Regulatory Utility Commissioners, Portland, Maine, October 1, 2001.

"Theory & Methods of Portfolio Risk Management" (with T. Parkinson), Tutorial presented to *Portfolio Risk Analysis & Management*, Infocast, Houston, February 16-18, 2000 and Chicago, October 2-4, 2000.

"Using Option Pricing Formulas," Presentation to *Pricing Wholesale Energy Products & Services*, Infocast, Houston, November 28-30, 2000.

"The Effect of Volatility Modeling on Management Decisions," Presentation to *Market Price Volatility*, Infocast, October 30 - November 1, 2000.

"Option Pricing in a Price Spike World," Presentation to *International Energy Pricing Conference*, EPRI, Washington, D.C., July 26-28, 2000.

"Applications of Portfolio Techniques to Fuel Decisions," Presentation to *Fuel & Power Supply Seminar*, EPRI, Cleveland, November 9-11, 1998.

"Managing Nuclear Generation Assets," Presentation to Generation Asset Management: Opportunities and *Challenges in the Electric Marketplace*, EPRI, Baltimore, July 13-15, 1998.

"Managing the Risks of Generation Assets," Presentation to *Integrating Risk Management for Fuel Supply & Power Sales,* Center for Business Intelligence, Houston, February 5-6, 1998

"Tactics for Matching Strategy & Market Opportunity through Hedging," Presentation to *Fuel Management: Innovative Fuel Strategies for a Price-Competitive Power Market*, Center for Business Intelligence, Colorado Springs, August 14-15, 1997.

"Implementing Risk Management in Electric Power," Presentation to *European Electricity Trading*, ICM Marketing Ltd., London, January 29-30, 1997.

"Integrating Fuel & Power Price Risk Management," Presentation to *Managing Fuel Risk*, Center for Business Intelligence, Dallas, December 12-13, 1996.

"Lessons From Deregulated Industries," Presentation to *Workshop on New Directions in Electricity Pricing*, EPRI, Palo Alto, May 7, 1996.

"Capacity Prices in a Competitive Power Market," Presentation to Symposium on *The Virtual Utility*, Saratoga Springs, March 31-April 2, 1996.

"Evaluating OPAs: The Art of Pricing Electricity Derivatives," Presentation to *Resource Acquisition in a Competitive Power Market*, International Business Communications, Chicago, October 30-31, 1995.

"Basis Risk in Energy Markets," Presentation to *Achieving Success in Evolving Electricity Markets*, EPRI, Atlanta, October 10-12, 1995.

"Risk and the Revolution in Finance: Implications for Planning," Presentation to *Strategic Resource Planning and Asset Management Forum*, EPRI, St. Petersburg, Florida, December 8-9, 1993.

"Why Small Firms Shun Discounted Cash Flow Analysis," Presentation to the Financial Management Association, Annual Meeting, San Francisco, October 22, 1992.

"Discount Rates in Utility Planning," Lecture to American Gas Association/Edison Electric Institute, Chicago, May 22, 1991.

"Weighted Average Cost of Capital: Before-Tax or After-Tax?" Presentation to the Budgeting and Financial Forecasting Committee, Edison Electric Institute/American Gas Association, Denver, September 10, 1990.

"Economic Evaluation of Utility Projects and Contracts," Seminar sponsored by the Electric Power Research Institute, San Diego, March 2-3, 1989.

"Planning for Utilities: The Value of Service," Paper presented to the Conference of Integrated Value-Based Planning, New Orleans, December 2, 1987.

"Capital Budgeting and the Cost of Capital," Lecture to the Marginal Cost Working Group, Boston, May 6, 1986.

"Capital Budgeting for Electric Utilities," Seminar sponsored by the Electric Power Research Institute, New Orleans, February 26-27, 1986.

"Risk and Capital Budgeting in the Electric Utility Industry," Paper presented to Rutgers University Advanced Workshop in Public Utility Economics and Regulation, New Paltz, New York, May 30, 1985.

"Critique of Rate of Return Methods in Public Utility Rate Cases," Lecture to Advanced Regulatory Studies Program, National Association of Regulatory Utility Commissioners, Williamsburg, Virginia, February 15, 1984.

"Utility Rate Shocks: The Problem and Possible Solutions," Paper presented to the Tenth Annual Rate Symposium, Institute for the Study of Regulation, Washington, DC, February 6, 1984.

TESTIMONY

Expert Report and Rebuttal Expert Report (with Yvette Austin Smith), in The Mangrove Partners Master Fund, Ltd. v. TransAlta Corporation et al., CV-19-00618554-0000, Ontario Superior Court of Justice, February 8, 2021 and April 4, 2021.

Affidavit and Supplemental Affidavit (both with Samuel A. Newell and Sang H. Gang) on Behalf of PJM Interconnection, L.L.C., Docket Nos. EL19-58 and ER19-1486, Federal Energy Regulatory Commission, August 5, 2020 and September 17, 2020.

Expert Report in Paul Morris v. Spectra Energy Partners (DE) GP LP, Spectra Energy Corp, and Spectra Energy Partners LP, in the Court of Chancery of the State of Delaware, C.A. No. 12110-VCG, June 2018.

Expert Rebuttal Report on behalf of CRS Proppants, LLC, in the Superior Court of the State of Delaware, C.A. No. N15C-08-111 MMJ, July 2016.

Testimony on behalf of East Kentucky Power Cooperative before the Kentucky Public Service Commission, Case No. 2016-00269, July 2016.

Testimony on behalf of East Kentucky Power Cooperative before the Kentucky Public Service Commission, Case No. 2015-00267, November 2015.

Testimony on behalf of East Kentucky Power Cooperative before the Kentucky Public Service Commission, Case No. 2013-00259, January 2014.

Expert Report in Pointe du Hoc Irrevocable Trust v. Commissioner of Internal Revenue, Docket No. 6041-05, October 2011.

Expert Report and Testimony in NPR Investments, LLC vs. United States of America, Case No. 5:05-CV-219-TJW. United States District Court for the Eastern District of Texas, Texarkana Division, November 2009 and March 2010.

Expert Report in John Campbell v. The Talbots, Inc. *et al.*, Court of Chancery of the State of Delaware, C.A. No. 5199-VCS, February 2010.

Testimony on behalf of the California Department of Water Resources, Sempra Energy Resources vs. California Department of Water Resources, No. GIC 789291, before the Superior Court in the State of California, November 2009.

Rebuttal Testimony on behalf of National Grid, plc and Keyspan Corporation, Case 06-G-1185, State of New York Public Service Commission, March 7, 2007.

Expert Report and Testimony in Klamath Strategic Investment Fund, LLC v. United States of America, Civil Action No. 5:04-cv-00278-TJW (lead case). United States District Court for the Eastern District of Texas, Texarkana Division, May 2006 and October 2006.

Expert Report and Declaration in re National Westminster Bank PLC v. The United States. United States Court of Federal Claims, No. 95-758 T, March 4, 2005 and July 12, 2005.

Expert Report in re Enron Corp., et al. v. Nevada Power Company and Sierra Pacific Power Company. United States Bankruptcy Court, Southern District of New York, February 23, 2005.

Expert Report in re New York Mercantile Exchange, Inc. v. Intercontinental Exchange, Inc. United States District Court, Southern District of New York, August 2004.

Prepared Direct Testimony in re Enron Power Marketing, Inc. and Enron Energy Services, Inc., Docket No. EL03-180-000 *et al*. Federal Energy Regulatory Commission, February 27, 2004 and January 31, 2005.

Expert Report in Idacorp Energy L.P. v. Overton Power District No. 5., The District Court of the Fourth Judicial District of The State of Idaho, In and For The County of Ada, CV OC 0107870D, February 28, 2003.

Prepared Direct Testimony on behalf of New York State Electric & Gas, Case 01-E-0359, State of New York Public Service Commission, August 2, 2001 and September 12, 2001.

Affidavit prepared on behalf of Tennessee Gas Pipeline Company, Docket No. RP80-97-058, Federal Energy Regulatory Commission, February 28, 1988.

SANG H. GANG

Vice President & Project Director
Sargent & Lundy Consulting Group

Education

- Electrical Engineering Graduate Work—University of Illinois at Urbana-Champaign—2006
- BS Electrical Engineering—University of Illinois at Urbana-Champaign—2003

Registrations

Professional Engineer (Illinois)

Proficiencies

- Power Project Development Support & Owner's Engineering Services
- Power Supply Planning
- Electric Transmission Planning
- Generator Grid Interconnection Planning
- Production Cost Modeling
- Integrated Resource Plans (IRPs)
- Electricity Markets – Capacity, Energy, and Ancillary Services
- Capital, O&M Costs, and Performance Estimates
- Power Project Due Diligence & Lender's Advisory Services
- Electrical System Analysis and Design

Responsibilities

As a Vice President and a Project Director within Sargent & Lundy's Consulting Group, Sang Gang leads a variety of conventional power plant and renewable energy consulting engagements with utility and IPP clients worldwide. Sang leads Sargent & Lundy's utility planning projects including cost and performance evaluation of various generation and interconnection options, long-term power supply planning, power procurement administration, and transmission and distribution planning. Sang also provides support for project development, owner's engineering, technical due diligence, independent engineering, construction monitoring, condition assessment, and technical advisory services for solar PV, onshore & offshore wind, energy storage, gas, nuclear, grid modernization, transmission, and other decarbonization projects throughout the world. He has significant expertise in the evaluation of technology, plant engineering and design, key project contracts, project economics, and performance records.

Sargent & Lundy Experience

Utility Planning and Advisory

Samsung C&T | 2022

Providing technical advisory services on converter and cable designs, as well as being responsible for key power system studies subject to the grid operator's approval for the 1.6-GW HVDC subsea transmission links project in the UAE.

DTE Energy

- 2022 | Provided decommissioning cost estimates for the utility's gas-fired and renewable generators.
- 2021-2022 | Evaluated power systems impacts of multiple retirement scenarios of the utility's coal units.

PJM Interconnection | 2021-2022

Collaborated with the Brattle Group for quadrennial review of cost of new entry (CONE) study for review of PJM's Variable Resource Requirement (VRR) curve.

City of Grand Island | 2021

Performed economic assessment of future generation mix scenarios, including coal, dual fuel gas turbines, reciprocal engines, and combined cycle. Utilizing hourly production cost modeling in PLEXOS.

NYISO | 2021

Performed buyer-side mitigation review of solar and battery energy storage projects bid into the NYISO market.

PJM Interconnection | 2021

Updated labor, equipment, and material costs for the reference technology in each of the EMAAC, SWMAAC, Rest of RTO, and WMAAC CONE areas. Filed an affidavit in support of PJM's informational filing to FERC.

Clean Energy USA | 2021

Performed distribution hosting capacity study for potential integration of solar DER interconnections to specific Delaware Electric Cooperative distribution circuits.

PJM Interconnection | 2020

Collaborated with The Brattle Group to analyze the gross avoidable costs rates (ACRs) for several types of existing generation including single-unit nuclear, multi-unit nuclear, coal, gas-fired combined-cycle, gas-fired combustion turbines, onshore wind, utility-scale solar PV, and behind-the-meter diesel generators. Our analysis helped PJM implement the December 2019 FERC order to expand the application of its Minimum Offer Price Review (MOPR) in its forward capacity market.

Indianapolis Power & Light Company | 2019–2020

Prepared, managed, and reviewed the results of an all-source RFP to obtain new supply-side electric capacity resources. The work included the complete preparation of the RFP package, analysis and review of the proposed power purchase contracts, interfacing with bidders through the process, development of both qualitative and quantitative bid evaluation methodologies, administration support for the RFP process, bid evaluation from technical and economic perspectives, and bid negotiation.

Northern Indiana Public Service Company | 2019–2020

Preparing a business case report for NIPSCO to support the utility's filing to the Indiana Utility Regulatory Commission to address the replacement of aging T&D infrastructure and grid modernization investments over a seven-year period. Sargent & Lundy is also preparing project scoping documents and cost estimates while maintaining a detailed database of the projects to facilitate planning and regulatory filings.

PSEG Long Island | 2020

Assisting PSEG Long Island in their 2020 Energy Storage RFI and RFP process. Sargent & Lundy's scope includes preparation of RFI/RFP document, managing the entire RFI/RFP process, qualitative and quantitative bid evaluations, and support during project selection and contract negotiations.

Confidential Clients

- 2020-2022 | Technical advisor for a bidder consortium for a 1.6-GW HVDC subsea transmission links project in the UAE. Supported from bid development stage through financial close.
- 2021-2022 | Performed production-cost model-based transmission congestion and solar PV generation curtailment analyses for multiple projects in California and Texas.
- 2021 | Evaluated economic feasibility of BESS addition to the operating onshore wind project in Texas by performing production-cost model-based generator curtailment analysis and BESS cost-benefit analysis.
- 2021 | Performed competitor analysis in support of a bidding strategy for the NY Bight offshore lease areas BOEM auction.

- 2020 | Performed detailed power flow study to support long-term T&D upgrade planning for the anticipated electrical power capacity increase at the client's electrical distribution system. The study entailed steady state N-0 and N-1 contingency load flow analysis and N-1-1 transient stability analysis to identify violating conditions and propose optimal mitigating solutions.
- 2020 | Collaborated with The Brattle Group to assess the technical and economic attractiveness of energy storage deployment options in preparation of the 3.1-GW energy storage target by 2035 in Virginia. Sargent & Lundy performed technical assessment of various energy storage technology options beyond lithium-ion, their technology maturity, performance characteristics, current costs, and a range of scenarios around potential future cost decline rates.
- 2019 | Supported a utility in their transmission planning by evaluating alternative generation and transmission solutions to mitigate areal overload conditions. Worked involved in detailed modeling and analysis using ISO grid model.
- 2018 | Performed engineering and economic evaluation of the client's electric power system with respect to a potential shutdown of a major generation asset. The engineering evaluation included reviews of the capital expenditure plans, fixed and variable O&M numbers, and various performance metrics such as availability, forced outages, and heat rates, which were all used as inputs to the economic model. The economic evaluation calculated breakdowns of various energy production costs such as market purchases/sales, fuel costs, variable O&M costs, and other fixed costs.

Arizona Electric Power Cooperative, Inc. (AEPCO) | 2019

Provided detailed capital cost, O&M cost, and performance estimates for different candidate resource types including simple cycle frame-type gas turbine, aeroderivative gas turbine, reciprocal internal combustion engine, and combined cycle gas turbine projects. Our deliverables were provided as input to the client's long-term resource planning.

Alberta Energy System Operator (AESO) | 2019

Provided technical and legal support to AESO related to its filing to the Alberta Utilities Commission on the design of the Alberta capacity market.

Lansing Board of Water and Light (BWL) | 2019

Supported the BWL Transmission and Distribution Engineering Department in development and completion of seven Asset Life Cycle Plan documents, which contain information regarding the characteristics, performance, condition, maintenance, modeling, and the proposed management plan.

Alberta Energy System Operator (AESO) | 2018

Worked with the Brattle Group to perform cost of new entry (CONE) study in preparation of AESO's inauguration of capacity market.

PJM Interconnection | 2017–2018

Worked with the Brattle Group to perform cost of new entry (CONE) study for review of PJM's Variable Resource Requirement (VRR) curve, which is an administratively determined representation of a demand curve for capacity used in the PJM Reliability pricing Model auction.

Sikeston Board of Municipal Utilities | 2017

Performed an evaluation of the costs and benefits of the client's existing interconnection configuration and alternative interconnection options.

United States Realty | 2013

US Steel Keystone Industrial Port Complex (KIPC)

Performed high-level condition assessment and valuation of the 30-MW KIPC electrical distribution system and developed cost optimization plan.

Renewable and Energy Storage

Dominion Energy | 2021-2022

Providing Owner's Engineering support for the utility's battery energy storage projects. Our support includes EPC technical specification, selection, negotiation, and design reviews during the execution stage.

Aypa Power

- 2022 | Providing Owner's Engineering support for a 100 MW battery energy storage project in California.
- 2021-2022 | Providing Owner's Engineering support for 150 MW battery energy storage project in Texas.

Hydrostor

- 2022 | Prepared IE report for the A-CAES projects in California in support of a DOE loan guarantee application
- 2021 | Provided Owner's Engineering support for two utility-scale battery energy storage projects in California.

Apex Clean Energy | 2021-2022
Prepared generic EPC technical specification for utility-scale battery energy storage projects.

AES Clean Energy

- 2022 | Prepared ISO-NE generator interconnection application for a solar project.
- 2021 | Prepared NYISO generator interconnection applications for multiple solar projects.

Dominion Energy | 2019-2020
Supported development of battery energy storage pilot projects. Scope included review of potential project candidates, preparation of EPC technical specification, and review of EPC bids.

Lincoln Clean Energy | 2019
Provided owner's engineering services to support conceptual layout design optimization, tracker technology selection, and EPC bid solicitation for the 400-MW 2W Permian Solar Project. Also provided owner's engineering services to support EPC bid solicitation for the 40-MW/40-MWh battery energy storage systems to be co-located with the Permian Solar Project.

Confidential Clients
- 2021-2022 | Performing audit of the Plant Accounting and Settlement System including solar performance model at a solar PV facility in the UAE
- 2021-2022 | Performing electrical design verification studies of the client's 800+ MW and 1200+ MW offshore wind projects.
- 2020 | Evaluated compliance of an 800+ MW offshore wind project with the interconnecting utility's reactive power requirements.
- 2020 | Performed a technical due diligence review of a 50-MW/200-MWh battery energy storage system in support of potential asset acquisition.
- 2020 | Prepared MISO interconnection application and supplemental technical requirements for 400-MW solar PV + 200-MW/800-MWh battery energy storage project.
- 2019 | Evaluated the impact of interconnecting the client's offshore wind project to the NYISO grid by performing System Reliability Impact Study.
- 2018 | New York & New Jersey, United States | Worked with NERA Economic Consulting to support a major offshore wind developer by performing competitor bid analyses for offshore wind auctions. Sargent & Lundy's scope included evaluation of potential interconnection points and estimates of capital costs, O&M cost, and annual generation levels.

- 2018 | Mexico | Owner's engineer for a new 100-MW solar PV project. Supported EPC and O&M contract negotiations and preliminary site and technology evaluations.
- 2018 | Prepared CAISO interconnection applications and supplemental technical requirements for 100+ MW solar PV + battery energy storage projects.
- 2018 | Prepared MISO interconnection application and supplemental technical requirements for 100+ MW solar PV project.
- 2018 | Michigan, United States | Performed GIS-based site identification study for multiple small utility-scale solar PV projects.
- 2017 | Georgia, United States | Performed technical due diligence review of two 60-MW biomass projects for potential asset acquisition.
- 2016 | United States | Developed conceptual layout, preliminary electrical design, equipment selection, energy production, detailed capital cost estimates, and LCOE calculation for a 20-MW solar PV project being developed in conjunction with reciprocal engine project.
- 2016 | United States | Developed conceptual layout, energy production, capital cost estimates and expenditure schedule for 20-MW solar PV project being developed adjacent to existing coal-fired power plant.
- 2016 | Performed market study and financial evaluation of adding a battery energy storage system to an existing wind project in the PJM region by assessing the new PJM capacity performance market to evaluate the battery system economics.
- 2016 | California | Performed technical and financial feasibility study of adding a battery energy storage system to the existing metropolitan railway system in San Francisco.

Inter-American Development Bank | 2015

Chile | Performed technical due diligence of a 100-MW single-axis tracking solar PV project.

Electric Power Research Institute (EPRI)

- 2014 & 2015 | Developed utility-scale performance and financial models of various PV technologies to update the EPRI Report, "Solar Energy Technology Guide - 3002001638."
- 2013 | Developed utility-scale performance models of various PV technologies to update the EPRI Report, "Engineering and Economic Evaluation of Central-Station Solar Photovoltaic Power Plant."

TerraForm Power | 2015

Ontario, Canada | Performed technical due diligence to support asset acquisition of two 10-MW solar PV projects.

International Finance Corporation

San Carlos Solar PV Projects

- 2015 | Performed operations monitoring of the three projects
- 2014 | Philippines | Performed independent solar resource and energy yield assessments and technical due-diligence reviews of three solar PV projects—22-MW, 18-MW, and 22-MW.

Overseas Private Investment Corporation

- 2015 | Jamaica | Content Solar PV Project
  - Performed pre-construction technical due diligence of a 22-MW solar PV project.
- 2015 | El Salvador | Real El Salvador Solar PV Project
  - Performed independent energy yield assessments to support financing of a portfolio of eight solar PV projects.
- 2014 | Pakistan | Confidential Wind Project
  - Performed Independent Engineering review of wind resource and energy yield assessment for a 50-MW wind project.
- 2013 | Tanzania | Confidential Solar PV Project
  - Performed Independent Engineering reviews of the solar resource, project financial projections, contract reviews, PV technology, independent design reviews, market pricing review, and O&M approach of a 3-MW solar PV project.

Macquarie Capital | 2013

Simon Solar PV Project

Performed lender's technical due diligence review of a 30-MW solar PV project in Georgia.

Standard Bank of South Africa

- 2013 | South Africa | Beaufort West PV Project
  - Performed Independent Engineering review of projected energy yield model of a 60-MW solar PV project.
- 2013 | South Africa | MetroWind Project
  - Performed Independent Engineering review of construction progress of a 27-MW wind project.

NextEra Energy Resources, LLC

- 2015 | Texas, United States | Javelina Wind Project
    - Performed Independent Engineering balance-of-plant reviews of a 250-MW wind project.
- 2013 | Texas, United States | Red River Portfolio
    - Performed Independent Engineering balance-of-plant reviews and compliance review of interconnection requirements of two commercially operating wind farms (255 MW total) to support re-financing.
- 2013 | Nebraska, United States Steele Flats Wind Projects
    - Performed Independent Engineering balance-of-plant reviews of a 75-MW wind project.

Gas and Coal Power

Venture Global LNG

- 2022 | Plaquemines LNG Export Facility | Performed transient stability analysis for the off-grid LNG liquefaction facility electrical system in Louisiana.
- 2019 | Calcasieu Pass LNG Export Facility | Supported Venture Global LNG in performing various power system modeling and studies of the off-grid electrical system for an LNG liquefaction facility in Louisiana.

Mirfa International Power and Water Company | 2015–2016

Mirfa Independent Water and Power Plant

Performed plant reliability assessment study through engineering assessment of the equipment operation and past failures history.

Confidential Clients

- 2022 | Provided IPP bid development support for a 800-MW combined cycle and LNG terminal project in Dominican Republic.
- 2022 | Provided IPP bid development support for a 2000+MW IWPP project in Qatar.
- 2021 | Performed technical due diligence for potential acquisition of an operating 2x1 7HA.02 combined cycle power plant in Pennsylvania.
- 2021 | Performed technical due diligence for potential acquisition of a 7HA.03 simple cycle project in New York.
- 2020 | Performed feasibility study to renovate and modernize an existing gas fired CHP boilers to increase the electricity output and continue supplying process steams to the customer.

- 2020 | Qatar | Supported preparation of an IPP bid for a 2300-MW and 100-MIGD project to provide electricity and water to the national utility.
- 2019 | Performed technical advisory services to support development of 800-MW combined cycle power plant and 345-kV transmission line project, including solicitation supports for onshore/offshore site investigations contractor, Power Island OEM, power plant EPC contractor, and substation and transmission EPC contractor.
- 2018 | Performed technical due diligence reviews of 2x300-MW coal plant in operation and 2x660-MW coal plant under construction, in support of potential asset acquisition.
- 2017 | Canada, United States, and Australia | Performed technical due diligence reviews of 16 coal- and gas-fired power plants in support of potential asset acquisition.
- 2017 | Mexico | Performed technical due diligence reviews of Norte-III combined-cycle power project, in support of potential asset acquisition.
- 2016 | United Arab Emirates | Performed technical due-diligence review of four-unit, 2,400-MW coal-fired power plant for potential lenders.
- 2015 | Mexico | Provided Owner's Engineering support for Independent Power Project (IPP) developer's bid to the Comisión Federal de Electricidad (CFE) for Noreste, Topolobampo-II, and Topolobampo-III combined cycle power projects.
- 2013 | Israel | Performed technical due-diligence review of a two-unit, 834-MW combined cycle power project for a potential lender.

Fadhili Plant Cogeneration Company | 2018

Fadhili Combined Heat and Power Project

Performed off-line audit of the Plant Accounting Settlement System and Fuel Demand Model as required by the Power Purchase Agreement (PPA) with one offtaker and Steam and Water Purchase Agreement (SWPA) with the other offtaker.

Dynegy | 2016

Project Manager for Independent Engineering review of four gas-fired combined cycle projects in the U.S.

GNPower Mariveles Coal Plant, Ltd. Co.

- 2016 | Project Manager for new relay setting development and existing relay setting reconstitution.
- 2016 | Project Manager for the LP turbine blade failure assessment.
- 2016 | Project Manager for technical feasibility evaluation of new Generator Circuit Breaker

addition and associated modifications to the plant auxiliary electrical distribution system.

Sithe Global | 2015–2016

Mariveles Coal Power Station

Reviewed major plant remediation program and performed independent engineering review of the two-unit, 300-MW coal-fired power plant in the Philippines for the major equity shareholder of the plant.

Shamal Az-Zour Al-Oula K.S.C. | 2016

Az-Zour North (AZN) Phase 1 Independent Water and Power Project

Project Manager for on-line audit of the Plant Accounting Settlement System and Fuel Demand Model.

Mirfa International Power & Water Company | 2015–2016

Mirfa Independent Water and Power Project

Project Manager for off-line audit of the Plant Accounting Settlement System, Fuel Demand Model, and Outage Mode Model.

Venture Global LNG | 2015–2016

Calcasieu Pass LNG Export Facility

Louisiana, United States | Supported Venture Global LNG as Owner's Engineer in technical feasibility studies such as the transient stability analysis of the off-grid electrical system for an LNG liquefaction facility.

Siddiqsons Energy | 2015

Karachi, Pakistan | Performed feasibility study and prepared technical specifications for developing a 350 MW supercritical coal-fired power plant.

SK Engineering & Construction (SK E&C) | 2014

Jangmoon Combined-Cycle Power Plant

South Korea | Provided technical advisory services to support SK E&C in the review of basic engineering of the two-unit, 2x2x1, 1,820-MW combined-cycle power project.

Korea Sothern Power Company (KOSPO) | 2014

Kelar Combined-Cycle Power Plant

Supported KOSPO as Owner's Engineer in the engineering design review of the 2x2x1, 517-MW combined cycle power project in Chile.

Hyundai Heavy Industries (HHI) | 2013–2014

Jeddah South Thermal Power Plant Stage 1

Saudi Arabia | Provided technical advisory services to support HHI in the basic engineering, detailed engineering, and start-up and commissioning of the four-unit, 2,640-MW supercritical oil-fired thermal power project.

Nuclear Power

Korea Hydro & Nuclear Power (KHNP) | 2016–2019

Project Manager for classroom training program consisting of 20 different technical subject courses in nuclear power plant design and analysis. Each course was offered over 4–8-week durations in the Sargent & Lundy's Chicago office.

KEPCO International Nuclear Graduate School | 2018

Project Manager for one-week long classroom training program about Root Cause Analysis (RCA) and Probabilistic Risk Analysis (PRA).

Dynegy | 2017

Performed due-diligence review of the Comanche Peak Nuclear Power Plant, focusing on identifying any material or major issues associated with the plant and operations that could have a significant cost impact.

Hyundai Engineering Co. (HEC) | 2016

Project Manager for technical advisory services and training program in nuclear power plant steam generator replacement.

Emirates Nuclear Energy Corporation | 2014

Barakah Nuclear Power Plant Units 1 and 2

Performed electrical review of selected safety-related plant systems against licensing basis as part of the Independent Design Review of Barakah Nuclear Plant Units 1 and 2 engineering design.

Tennessee Valley Authority (TVA), Browns Ferry Nuclear Plant

- 2009–2013 | Emergency Diesel Generator Governor Upgrade
- 2012–2013 | NFPA-805: EECW System Circuit Modification
- 2012 | NFPA-805: Emergency Diesel Generator Protective Relay Circuit Modification
- 2012 | LPCI MG Set Abandonment

- 2010–2011 | Service Building Transformer Replacement
- 2010–2012 | Generator Voltage Regulator Replacement
- 2008–2012 | Low Voltage Circuit Breakers Replacement
- 2008–2012 Emergency Diesel Generator Turbocharger Lube Oil System Modification

Testimony and Regulatory Filings

- 2021-2022 | Expert testimony for Cause No. 19-1614-C26 In the Matter of Litigation between City of Georgetown and Buckthorn Westex, LLC in the 26th District Court of Williamson County, Texas.
- Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. Attachment D to Second Compliance Filing concerning Application of the Minimum Offer Price Rule, June 1, 2020.
- Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), Supplemental Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. Attachment to Re: PJM Interconnection, L.L.C., Docket Nos. EL16-49, EL18-178, ER18-1314 Errata to PJM Compliance Filing re: Hope Creek Nuclear Plant, March 25, 2020.
- Before the Federal Energy Regulatory Commission, Docket No. EL16-49, ER18-1314-000, -001, EL18-178-000 (Consolidated), Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C. Attachment D to Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for an Extended Comment Period of at least 35 Days, March 18, 2020.
- Before the Alberta Utilities Commission, Proceeding No. 23757, Alberta Electric System Operator (AESO) Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, Participated in the hearing as a member of the AESO's witness panel on May 1-3, 2019.
- Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Answering Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on behalf of PJM Interconnection, L.L.C, regarding Cost of New Entry Parameters, Attachment B to Answer of PJM Interconnection, L.L.C. to Protests and Comments, December 17, 2018.

- Before the Federal Energy Regulatory Commission, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John H. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C." regarding the Cost of New Entry, accompanied by report, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, October 12, 2018.

Languages

- Korean (Fluent)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Samuel A. Newell**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

____

Samuel A. Newell

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **James A. Read Jr.**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

James A. Read Jr.

Subscribed and sworn to before me, the undersigned notary public, this 28 day of September 2022.

Notary Public

Gerard M. Rooney
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Commission Expires
6/30/2028

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Sang H. Gang**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

Sang H. Gang

Subscribed and sworn to before me, the undersigned notary public, this 28th day of September 2022.

OFFICIAL SEAL
BRENDA CAMPBELL
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:08/27/23

Brenda Campbell
Notary Public

Attachment F

Affidavit of
Johannes P. Pfeifenberger
and Bin Zhou

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF
JOHANNES P. PFEIFENBERGER AND BIN ZHOU
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. Our names are Johannes P. Pfeifenberger and Dr. Bin Zhou. We are both Principals at The Brattle Group. We are submitting this affidavit in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to adjust the administrative Cost of New Entry ("CONE") parameter, representing the cost of building a generation plant for use in PJM's capacity market (known as the Reliability Pricing Model or "RPM"). In particular, our affidavit addresses the appropriate after-tax weighted-average cost of capital ("ATWACC") used in the calculation of the CONE.

2. Mr. Johannes P. Pfeifenberger is an economist with a background in power engineering and over 25 years of work experience in the areas of regulated industries, energy policy, and finance. He received a M.A. in Economics and Finance from Brandeis University and a M.S. in Electrical Engineering with a specialization in Power Engineering and Energy Economics from the University of Technology, Vienna, Austria. He is the author or co-author of numerous reports and presentations addressing capacity market matters, including detailed reviews of (and CONE estimates for) the PJM capacity market in 2008, 2011, 2014, and 2018.

3. Dr. Bin Zhou received a B.A. in World Economy from Fudan University in China and a Ph.D. in International Economics and Finance from Brandeis University. He has twenty years of consulting experience in financial institutions, utilities, energy, and pharmaceutical industries. In recent years, his practice has been focused primarily on financial analysis and due diligence in support of large-scale infrastructure projects in the oil, gas, and utilities industries; on economic analysis of complex tax transactions; and on international transfer pricing controversies. He has also been involved in estimating merchant generation costs of capital for a number of litigation projects and utility regulatory proceedings, including as a co-author of, or advisor to, the Brattle Group's CONE studies for PJM in 2011, 2014, and 2018.

4. Exhibit No. 1 contains full citations to our prior work and a more complete description of our qualifications and expert witness experience.

5. As explained in the accompanying affidavit of Dr. Samuel A. Newell, Mr. John Hagerty, and Mr. Sang Gang, PJM retained Brattle in July 2021 to help review, as required periodically under PJM's tariff, the Variable Resource Requirement Curve used as the demand curve in RPM auctions, including key components of that curve: the CONE value and the method to estimate the net revenues the CONE plant would earn in the PJM Region's energy and ancillary services markets. We participated in the development of the CONE estimate and co-authored the report, "PJM CONE 2026/2027 Report" ("2022 CONE Study"), a copy of which is attached to the affidavit of Dr. Newell, Mr. Hagerty, and Mr. Gang as Exhibit 2.

6. Specifically, we were responsible for the ATWACC estimate, including the capital structure and estimated costs of debt and equity. In the 2022 CONE Study, originally completed in April 2022 using data as of March 31, 2022, we estimated that the ATWACC for the new entry plant would be 8.0%. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.2%. Between March 31 and August 31, 2022, the Federal Reserve raised short-term interest rates three times (0.5% on May 5, 0.75% on June 16, and 0.75% on July 27)[1] and continues to aver future rate hikes to control inflation.[2] As a result, the long-term interest rate increased by 81 basis point (0.81%). As described below in detail, we update our ATWACC estimate as of August 31, 2022, and find that the ATWACC for the new entry plant has increased to 8.85%. Our recommended financing components consistent with this overall ATWACC are a debt ratio of 55%, an equity ratio of 45%, a cost of debt of 6.3% (based on the median shown in Table 1 below), and a cost of equity of 14.1%.[3]

7. ATWACC serves as a discount rate to translate uncertain future cash flows into present values and help derive the annual CONE value that makes the project net present value equal to zero. Our ATWACC methodology, which has been used consistently for many years in Brattle's work involving cost of capital for merchant generation projects, is derived from transparent market-based evidence of that cost. To start, we developed our recommended cost of capital by an independent estimation of the ATWACC for three publicly-traded merchant generation companies and independent power producers ("IPPs"), supplemented by additional market evidence from analysts' valuation of recent merger and acquisition ("M&A") transactions. These market- and transaction-based data are the most direct, reliable, transparent, and verifiable evidence on the cost of capital of companies in the merchant generation business. They reflect not only the capital providers' required

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1 *See* Press Release, Federal Reserve Board, Decisions Regarding Monetary Policy Implementation (May 4, 2022). *See also* Press Release, Federal Reserve Board, Decisions Regarding Monetary Policy Implementation (July 27, 2022); Press Release, Federal Reserve Board, Decisions Regarding Monetary Policy Implementation (June 15, 2022). The Federal Reserve increased the short rate by 0.25% on March 17, 2022 (*see* Press Release, Federal Reserve Board, Decisions Regarding Monetary Policy Implementation (March 16, 2022)).

2 *See* Prerana Bat & Indradip Ghosh, *Fed set for another 75-basis-point rate hike; early pivot unlikely: Reuters poll* (September 12, 2022), https://www.reuters.com/markets/us/fed-set-another-75-basis-point-rate-hike-early-pivot-unlikely-2022-09-13/.

3 ATWACC = 6.3% × 55% × (1 – 27.2%) + 14.1% × 45% = 8.85%, where 27.2% (= 8.5% + (1 – 8.5%) × 21%) is the combined federal-state tax rate, with 8.5% state taxes deductible for federal taxes.

compensation for the risks, but also the borrowers' willingness to bear these risks. As consistent with our procedures before, we then made an upward adjustment towards the upper end of the range from the comparable company results to reflect the relatively higher risk of uncontracted merchant operations.

8. The analytical framework, supporting data, and rationales for these recommendations are fully set forth in the 2022 CONE Study, which (insofar as the study addresses the cost of capital) was prepared by us or under our supervision and direction.

9. In the rest of this affidavit, we report the changes in inputs to our updated ATWACC recommendation of 8.85%.

Updated ATWACC for Publicly Traded Companies and Fairness Opinions

10. Table 1 reports our base-case ATWACC results for three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 8.2% for AES Corporation to 8.8% for NRG Energy, Inc. These results are based on the updated inputs on: (a) the risk-free rate, (b) betas, (3) costs of debt; and (4) capital structure ratios. We report in the left-hand side of Figure 1 the results from this base case and three sensitivity checks under alternative assumptions.

Table 1. Base-Case ATWACC (As of August 31, 2022)

Company	S&P Credit Rating [1]	Market Capitalization [2]	Long Term Debt [3]	Beta [4]	CAPM Cost of Equity [5]	Equity Ratio [6]	Cost of Debt [7]	ATWACC [8]
AES Corp	BBB-	$16,908	$19,174	1.45	14.2%	39%	5.9%	8.2%
NRG Energy Inc	BB+	$9,882	$8,171	1.13	11.8%	59%	6.3%	8.8%
Vistra Corp	BB	$10,500	$12,224	1.25	12.8%	48%	6.4%	8.6%

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 8/31/2022, millions USD.
[4]: Computed 3-year weekly betas based on stock price returns and index returns.
[5]: RFR (3.43%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

a. *The Risk-free Rate:* The 15-day average of the risk-free rate ending March 31 was 2.62%. This same average increased to 3.43% on August 31, 2022. The latter figure is used in Table 1. In our 2022 CONE Study, we estimate the risk-free rate based on *BlueChip Economic Indicators'* forecasts for long-term Treasury interest rates from professional economists as an alternative measure of the risk-free rate. The forecast for 2026–2027, adjusted from 10-year to 20-year maturity, is 3.5%. Since *BlueChip* has not published its new long-term interest rate forecast, we keep it at the same level.

b. *Betas:* We estimate the return on equity (ROE) using the Capital Asset Pricing Model. The ROE for each company, shown in column [5] of Table 1, is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" measures each company stock's (three-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index. We updated the betas for the three companies using 3-year weekly stock returns on Wednesdays ending August 31, 2022. The updated betas are shown in column [4] of Table 1. In addition, as a sensitivity, we updated the betas reported by Value Line. They are shown as alternative cases in Figure 1.

c. *Costs of Debt:* In our previous analyses, we estimated the costs of debt ("COD") by the average bond yields corresponding to the unsecured senior credit ratings for each merchant generation company (issuer ratings) as well as each company's actual COD (averages across long-term debt). The updated costs of debt are shown in Table 2 and their impacts on the ATWACC are shown in Figure 1.

Table 2. Cost of Debt (as of August 31, 2022)

Company	S&P Credit Rating	Ratings-Based Cost of Debt	Company-Specific Cost of Debt
[1]	[2]	[3]	[4]
AES Corp	BBB-	5.4%	5.9%
NRG Energy Inc	BB+	5.8%	6.3%
Vistra Corp	BB	6.2%	6.4%

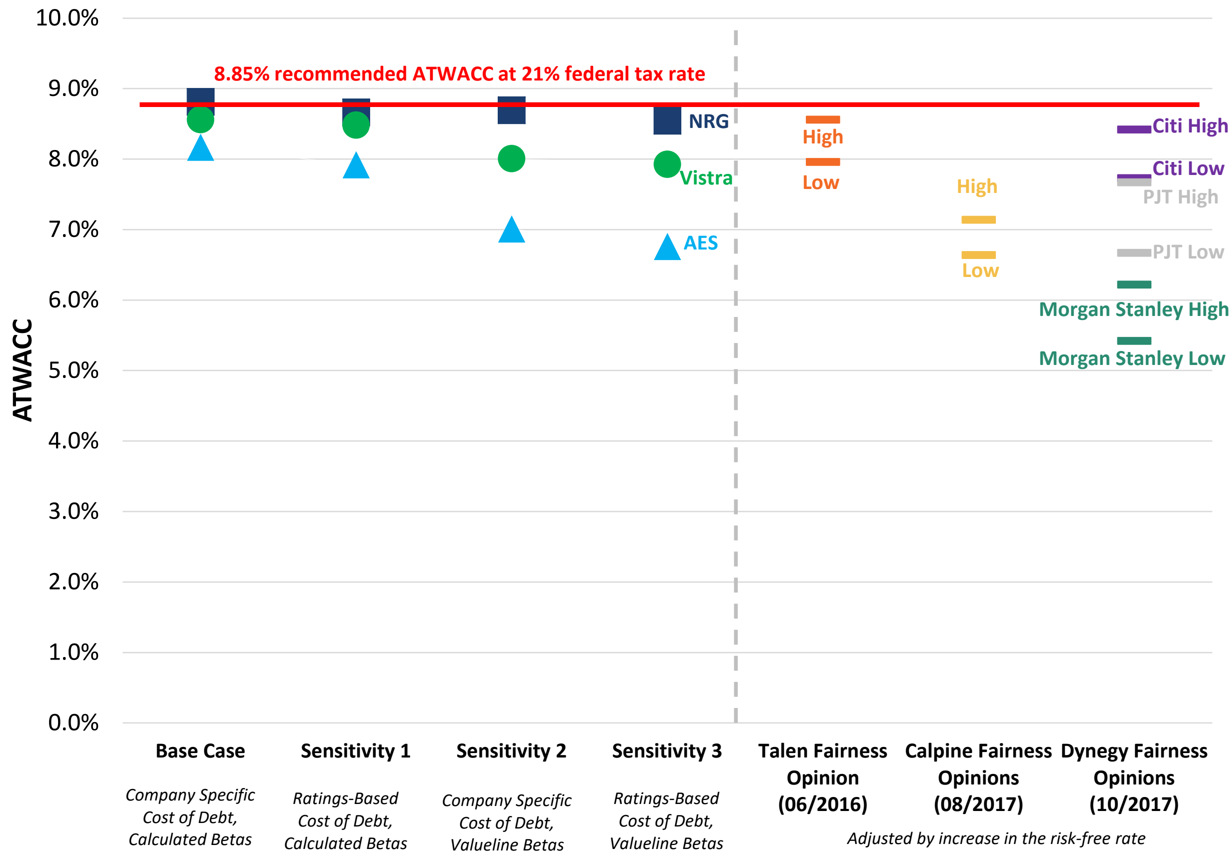
d. *Capital Structure Ratios:* In our April report, we estimate the debt and equity ratios as averages over the 3-year period between March 31, 2019 and March 31, 2022. We now updated them to be between August 31, 2019 and August 31, 2022. More specifically, the August 31, 2022 debt and equity ratios are based on debt balances as of June 30, 2022 (the last reported quarterly numbers) and market capitalizations as of August 31, 2022. The updated equity ratios are shown in Table 1 and Figure 1.

11. As in the past, our 2022 CONE Study also includes the risk-free-rate-adjusted discount rates used in the fairness opinions for three M&As in the IPP industry: Talen's acquisition by Riverstone Holdings LLC announced on June 2, 2016, Calpine's leverage buyout by Energy Capital Partners announced on August 17, 2017, and Dynegy's acquisition by Vistra announced in October 27, 2017. At the announcement time of those transactions, the prevailing risk-free rates were 2.84%, 3.04%, and 2.92%, respectively. We adjusted the range of discount rates used in each transaction by the increase in risk-free rates from the transaction dates to August 31, 2022. These adjustments, based solely on the change in risk free rates, will understate the increase in the cost of capital as the prevailing federal corporate tax income tax rate was 35% before 2018.

Updated ATWACC Recommendation

12. The updated results and our updated recommendation is shown in Figure 1.

Figure 1. Summary of Base Case, Alternative Cases, and Updated Fairness Opinions



13. Consistent with our prior methodology, we select 8.85%, within the upper end of the range from the comparable company results and the updated fairness opinions, to reflect the relatively higher risk of uncontracted merchant operations.

14. As an additoinal point of reference, Figure 2 compares our updated recommendation and the implied risk premium against those from our three previous PJM CONE reports. The red dots represent the recommended ATWACC, the line is the prevailing risk-free rate, and the bars indicate the resulting risk premium (ATWACC − the risk-free rate).[4] Between 2011 and 2018, the risk-free rate has been steadily declined, dropping from 4.2% in 2011 to 2.96% in 2018. Over the same period, our recommended ATWACC of merchant generation declined at a slower pace[5] than the risk-free rate.[6] Between 2018 and August 31, 2022 (the as of date

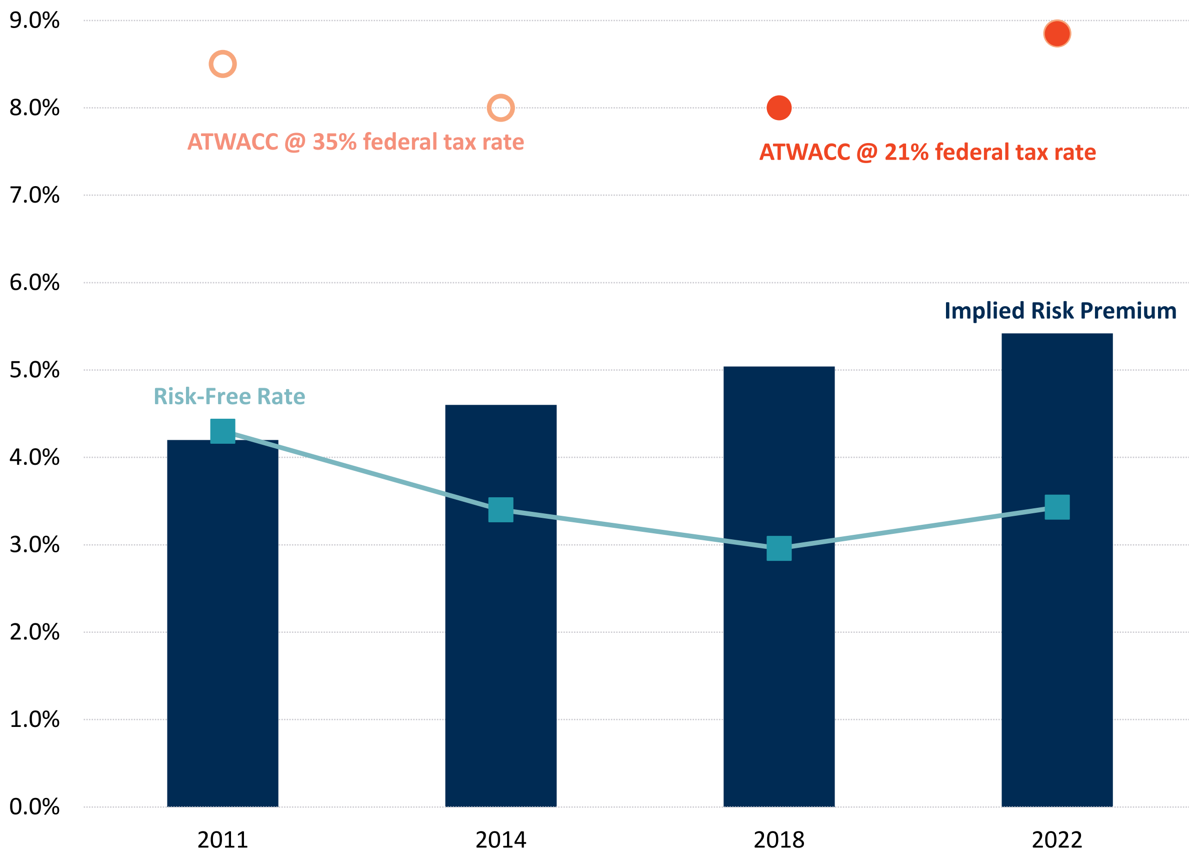
4 For 2011 and 2014, the applicable federal corporate income tax rate was 35%. For 2018 and the current study, the tax rate is 21%.

5 Between the 2011 report and the April 2022 report, the risk free rate declined 39% from 4.3% to 2.6%. During the same time period, the ATWACC declined 6% from 8.5% to 8%.

6 The reduction in the tax rate is partially responsible for the constant ATWACC recommendation for 2018: all else equal, a lower federal tax rate increases the ATWACC.

of this ATWACC update), the risk-free rate has increased from 2.96% to 3.43%. Our ATWACC of merchant generation has increased from 8.0% to 8.85%. The implied risk premium increased from about 5% in 2018 to 5.4% as of now. The higher implied risk premium is driven by changes in the marketplace: higher betas, higher cost of debt, and higher equity ratios, especially for NRG, which sets the upper range of the ATWACC estimates.

Figure 2. Comparison of ATWACC and Implied Risk Premium



15. This concludes our affidavit.

Exhibit No. 1

Johannes P. Pfeifenberger
and Bin Zhou
Qualifications

QUALIFICATIONS OF JOHANNES P. PFEIFENBERGER

Johannes Pfeifenberger is a Principal of The Brattle Group where he is a member of the firm's Utility Regulation and Electric Power practices. He received a M.A. in Economics and Finance from Brandeis University and holds a B.S. and M.S. ("Diplom Ingenieur") in Electrical Engineering, with a specialization in Power Engineering and Energy Economics, from the University of Technology in Vienna, Austria.

Mr. Pfeifenberger is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), and an IEEE Senior Member. He frequently serves as an advisor to research initiatives by the Energy Systems Integration Group (ESIG) and the US Department of Energy's National Labs. Before joining Brattle, he was a Consultant for Cambridge Energy Research Associates and a Research Analyst at the Institute of Energy Economics of the University of Technology in Vienna, Austria.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket No. RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Affidavit of Johannes P. Pfeifenberger on Behalf of The Natural Resources Defense Council (NRDC), filed by the Public Interest Organizations, August 17, 2022.

Before the Alberta Utilities Commission, Proceeding No. 26911, AESO Bulk and Regional Rate Design and Modernized DOS Rate Design Application, Written Evidence of Johannes P. Pfeifenberger and John Tsoukalis, on behalf of Capital Power Corporation, March 28, 2022.

Before the Federal Energy Regulatory Commission, Docket No. ER22-995-000, *Prepared Direct Testimony of Johannes P. Pfeifenberger* on behalf of MidContinent Independent System Operator, in the matter of Midcontinent Independent System Operator, Inc., and MISO Transmission Owners Proposed Revisions to MISO Tariff to Modify Cost Allocation for Multi-Value Projects, February 4, 2022.

Before the Federal Energy Regulatory Commission, Docket No. RM21-17, *Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs* (with others), report by the Brattle Group and Grid Strategies filed by several parties, October 12, 2021; and *A Roadmap to Improved Interregional Transmission Planning* (with others), report filed by the Natural Resources Defense Council (NRDC), November 30, 2021.

Before the Federal Energy Regulatory Commission, Docket No. ER20-2308, *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty* on behalf of LS Power, *re:* Comments in Support of PJM Stakeholder Approved Section 205 Filing (for treatment of End of Life Projects), July 23, 2020.

Before the Federal Energy Regulatory Commission, Docket No. ER20-1006, re *DATC Path 15*, Prepared Direct Testimony of Johannes P. Pfeifenberger on behalf of DATC Path 15 LLC, February 14, 2020.

Before the Federal Energy Regulatory Commission, Docket No. ER20-644-000, *Affidavit of Johannes P. Pfeifenberger and John Tsoukalis* on behalf of Golden Spread Electric Cooperative, *re:* Comments on SPP Compliance Filing Revising Fast Start Pricing Practices, January 21, 2020.

Before the Public Utilities Commission of California, Application 16-10-12, *Ten West Link Economic and Public Policy Benefits and Costs Analysis, Technical Report*, prepared for DCR Transmission LLC (with J. Chang., J.M. Hagerty, M. Tracy, and J.I. Pedtke, December 20, 2019.

Before the Arkansas Public Service Commission (Docket No. 19-035-U), the Texas Public Utilities Commission (Docket No.49737), the Louisiana Public Service Commission (Docket No. U-35324), and the Corporation Commission of Oklahoma (Cause No. PUD 201900048), *Testimonies of Johannes P. Pfeifenberger in the Matter of the Acquisition of Wind Generation Facilities on behalf of Southwestern Public Service Company and Oklahoma Public Service Company*, July 2019 through February 2020.

Before the Public Service Commission of Wisconsin, Docket No. 5-CE-146, *Rebuttal_and Sur Surrebuttal Testimony of Johannes Pfeifenberger in Support of the Applicant*, on behalf of American Transmission Company LLC, ITC Midwest LLC, and Dairyland Power Cooperative, for Authority to Construct and Operate a New 345 kV Transmission Line from the Existing Hickory Creek Substation in Dubuque County, Iowa, to the Existing Cardinal Substation in Dane County, Wisconsin, to be Known as the Cardinal-Hickory Creek Project, June 2019.

Before the Federal Energy Regulatory Commission, Docket No. EL19-34-000, *Affidavit and Reply Affidavit of Johannes P. Pfeifenberger and Akarsh Sheilendranath* on behalf of Brookfield Energy Market LP, January 18 and February 25, 2019, Exhibit A to *Complaint and Request for Fast Track Processing of Brookfield Energy Marketing LP*.

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Dr. Bin Zhou is a Principal in The Brattle Group's Securities Practice. He has over twenty years of consulting experience in consumer goods, energy, financial institutions, pharmaceutical and medical devices, technology, telecommunication, and utilities industries. He specializes in the application of financial economics, management accounting, business organizations, and taxation principles to a variety of consulting and litigation settings.

Dr. Zhou has supported testifying experts and led large engagement teams in many high-profile transfer pricing (Microsoft, Facebook, Coca-Cola, Boston Scientific / Guidant, Eaton, AstraZeneca, and GlaxoSmithKline), bankruptcy (Caesars, U.S. Steel Canada, Nortel, Ambac, and Enron), and securities litigations (MBIA, Parmalat, and Enron). His work has been primarily focused on the economic analysis of transfer pricing disputes involving hard-to-value intangibles, economic substance of complex transactions, solvency analysis and fraudulent conveyance claims, structured finance transactions, financial statement analyses, and damages. His most recent experience also includes economic profit analyses in anti-trust matters, a special litigation committee investigation of a large acquisition in the software industry, two international arbitration cases involving valuation of Korean publicly listed companies, intellectual property transfers in distressed companies, and cost allocation of mutual fund advisory fees.

Dr. Zhou received a Ph.D. in International Economics and Finance from Brandeis University in 1998. He also holds an MA in Economics from Washington State University, and a BA in Economics from Fudan University of China.

AREAS OF EXPERTISE

- Bankruptcy, Restructuring, and M&A Litigation
- Securities Litigation
- Transfer Pricing and Other Tax Controversies
- Risk Analysis and Valuation
- Contract Disputes and Damages

EXPERIENCE

Bankruptcy, Restructuring, and M&A Litigation

- In a recently settled dispute involving an online travel reservation company (the client) and its lenders, Dr. Zhou led a Brattle team to analyze the impact of COVD-19 on industry, the company's pro forma financial reporting, and the impact of an intellectual property transfer on the company.
- In an international arbitration involving a restructured engineering, procurement, and construction (EPC) project, Dr. Zhou supported an academic expert to opine on whether the EPC contractor's limited liability should be disregarded and its parents made parties to the arbitration.
- In an ongoing dispute between J. Crew and some of its lenders (the client), Dr. Zhou supported a Brattle Principal to value the company before the transfer of J. Crew's brand intangibles to an affiliated company beyond the reach of the lenders.
- In two ongoing international arbitration disputes against the Republic of Korea (the client), Dr. Zhou supports an outside expert on the valuation of several publicly-traded companies in the Samsung Group and two U.S.-based investor funds' trading strategies involving these companies.
- In a recently concluded special litigation committee (SLC) investigation of a large publicly traded over its acquisition of a cloud-based software-as-a-service target company, Dr. Zhou supports an outside expert to advise the SLC on various economic, industry, and valuation issues. He and his team reviewed internal valuation, fairness opinions by external financial advisors, due diligence, internal budgeting and post-acquisition integration planning. He led the Brattle team to assist counsel for the SLC counsel in document review, witness interviews, SLC presentations, and mediation.
- In the bankruptcy of Avaya (a telecom service provider), on behalf of a large equity investor, Dr. Zhou led a project team to analyze Avaya's patent portfolios, its competitive positions in the industry, and post-bankruptcy valuation. The case settled before the confirmation hearing.
- In Caesars Entertainment Operating Company's bankruptcy, Brattle was retained by Apollo Global Management to provide valuation and solvency analyses over 15 transactions between 2008 and 2014. The transactions involved the sale of gaming and lodging properties, intellectual property, and other related assets. Dr. Zhou supported an in-house expert. The case settled.
- In U.S. Steel Canada's insolvency proceeding in Ontario, Dr. Zhou assisted an in-house expert to rebut assertions by the opposing parties that certain intercompany loans should be re-characterized as equity. The Court ruled in our client's favor.
- In Nortel's bankruptcy allocation and claims proceedings, Dr. Zhou supported an allocation expert and a transfer pricing expert on behalf of Nortel's UK pension fund. The key issue before the joint U.S. and Canada courts is the allocation of Nortel's $7.3 billion liquidation proceeds, mostly from patents-related intangible assets, among Nortel's three primary bankruptcy estates (Canada, U.S., and EMEA). He led the Brattle team through all phases of the expert reports, deposition, and trial. The allocation decisions were issued in our client's favor.

- In Ambac's bankruptcy proceeding, Dr. Zhou assisted Ambac in its tax dispute with the IRS regarding the taxpayer's $700 million tax refund during the recent financial crisis. The dispute involves the appropriate taxation of credit derivatives, currently an unsettled area in tax policies and regulation. The case settled in our client's favor.
- In a confidential assignment involving a fraudulent conveyance action in Tribune's bankruptcy, The Brattle Group was retained as consulting experts to review several valuation and solvency analyses performed at the time of the transaction.
- In several suits against Ernst & Young brought by Refco's litigation trustee, Dr. Zhou advised counsel E&Y against allegations of breach of fiduciary duty. He performed forensic analysis of the financial institution's tax returns and workpapers of the audited financial statements. He also analyzed whether the alleged breach of fiduciary duty could have caused the brokerage's demise. The case was recently dismissed.
- In a number of litigations against Bank of America in Parmalat's bankruptcy, Dr. Zhou advised counsel for Bank of America regarding a number of structured finance transactions it arranged for Parmalat's Latin American subsidiaries. He supported an outside academic expert to provide a coherent framework to examine a multinational enterprise's management of its financing strategy in the emerging markets. Against this framework, he analyzed various features of the financing and their overall impact on Parmalat's indebtedness.
- On behalf of Deutsche Bank, between 2003 and 2007 Dr. Zhou was extensively involved in a number of Enron-related securities and bankruptcy litigations. He supervised the project team to analyze Enron's off-balance-sheet debt, its sources and use of cash flows, and the related disclosure. He reviewed the transaction documents and journal entries for over a hundred special-purpose vehicle transactions, and led the project team to analyze the transactions' impact on Enron's key financial ratios and their impact on Enron's creditworthiness. He also supported testifying experts on economic and accounting issues of certain structured finance and tax transactions.
- In a bankruptcy proceeding, Dr. Zhou supported an academic expert to analyze whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil."
- For Global Crossing's Board of Director, Dr. Zhou reviewed the business purposes of certain fiber optic capacity lease transactions, conducted forensic analysis of the associated accounting records, and reviewed SEC disclosure regarding its pro forma accounting. He also examined the market reaction to the company's various disclosures.

Securities Litigation

- Dr. Zhou advised plaintiff counsel in a class action against a master limited partnership over its public disclosure on maintenance capital expenditure, and damages to the class.
- Dr. Zhou assisted counsel for the Federal Deposit Insurance Corporation (FDIC) in a warrant and representation dispute between JP Morgan and the FDIC. He advised on the relevant accounting and disclosure issues.

- In a valuation dispute between Barclays and a mortgage company related to the repo financing of a multi-billion MBS-based derivative portfolio, Dr. Zhou supported a Brattle principal to mark to market the portfolio around August 2007 and quantify the impact of market illiquidity on the portfolio valuation.
- In an insurance dispute between a broker-dealer (client) and a large bank whose natural gas trader caused hundreds of million trading losses amid valuation irregularities, Dr. Zhou provided consulting support in tracing the losses to its various causes. The case was recently settled on favorable terms to our client.
- For a 10b(5) securities class action against MBIA, Dr. Zhou provided consulting support to the company's mediation and settlement discussions with the plaintiffs. He reviewed the company's mandatory and voluntary disclosures during the 2007/2008 financial crisis regarding its exposure to subprime collateralized debt obligation, estimated the but-for stock price under alternative disclosures, and calculated the potential damages to shareholders.
- In a criminal sentencing case against a bank executive who was found guilty of material misrepresentation, Dr. Zhou led the project team to analyze the bank's valuation analysis and accounting records for certain complex mortgage-related derivatives, and reviewed a third-party's analyses that led to the bank's financial restatements. He also evaluated the loss causation and estimated the damages caused by the executive's misconduct.
- In a shareholder class action lawsuit against Scottish Re where plaintiffs sued the company over its failure to book and disclose a valuation allowance for deferred tax assets, Dr. Zhou analyzed several of the company's statutory reserve securitization transactions, which allegedly should have caused the company to recognize the valuation allowance earlier. He assisted counsel for the company to identify factual evidence to refute the connection between the securitization transactions and the decision to book the valuation allowance. The case is settled.

Transfer Pricing and Other Tax Controversies

- In Facebook's ongoing transfer pricing dispute with the IRS (the client), Dr. Zhou led a project team to review Facebook's general ledgers and financial reporting for certain acquisitions and intercompany transfers, and analyzed the intercompany allocation of R&D and stock-based compensation.
- In Coca-Cola's transfer pricing dispute with the IRS, Dr. Zhou led Brattle's consulting team to perform an independent functional analysis of the taxpayer's international operations and the value drivers of the industry, and to propose an arm's length prices for the transfer of the company's product and marketing intangibles.
- In the bankruptcy of Gawker Media (a now defunct online media company), Dr. Zhou advised the bankruptcy trustee on the intercompany transfer pricing among the content creation, distribution, and sales functions.
- Brattle was retained by Boston Scientific / Guidant to value the allocation of intangibles between U.S. and foreign entities, and evaluate the best transfer pricing method. Dr. Zhou led the project team to support an in-house transfer pricing expert. The case settled before trial.

- On behalf of a number of U.S. subsidiaries of a foreign-headquartered multinational corporation, Dr. Zhou led the project team to analyze the U.S. subsidiaries' intercompany financing from a foreign affiliate, valuation of the businesses, and ability to service the debt. The cases settled.
- In Eaton's successful challenge to an IRS adjustment involving two advance pricing agreement cancellations, Dr. Zhou led support teams for three outside and one in-house experts on issues ranging from managerial accounting, technology licensing, and transfer pricing methods. Dr. Zhou played an instrumental role in supporting a cost accounting expert on Eaton's managerial accounting and APA compliance.
- In Amazon's successful Tax Court petition involving its transfer pricing dispute with the IRS. Dr. Zhou supported an outside licensing expert on the structure of arm's-length licenses of marketing intangible property.
- Brattle provided support to a large Canadian bank in a dispute with the Canada Revenue Agency over the proper allocation of a multi-billion dollar securities class action settlement in the U.S. The Brattle team assessed the risk positions and risk-bearing abilities of each entity to the transactions implicating the Canadian bank. Dr. Zhou is a key member of the project team.
- In Broadwood Investment Fund et al. v. U.S.A. (tax dispute involving distressed assets/debt), Dr. Zhou assisted a Brattle and two external experts analyzing the reasonable profitability of the taxpayers' investment in non-performing loan portfolios. The case was dismissed on summary judgment right before the trial.
- Dr. Zhou worked on a tax dispute on behalf of AstraZeneca against U.K.'s Revenue and Customs. He supported Prof. Stewart Myers from MIT's Sloan School of Management to analyze whether the licensing agreements for several drugs between the U.K. parent and its Puerto Rican subsidiary were arm's length.
- Dr. Zhou worked on a tax dispute with the IRS on behalf of Wells Fargo with respect to several of the bank's leasing transactions. He prepared evidence and analyses on the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, the choice of risk- and tax-adjusted discount rates for the municipal agencies (lessees), and the probability of their exercise of purchase option at the end of the lease.
- In a tax dispute between ExxonMobil and the Australian tax authority, Dr. Zhou led the project team to estimate the fair value of certain petroleum products at potential taxing points upstream of the actual sales.
- Dr. Zhou assisted counsel for GlaxoSmithKline in its tax litigation against the I.R.S. involving valuation of intellectual property rights. He assisted in the development of a life-cycle model of a successful drug.
- In a dispute concerning the interest deduction claimed by HSBC Bank, Dr. Zhou analyzed whether the U.S. branches of the UK bank maintained adequate capital and whether the borrowing and lending transactions between the affiliated parties were arm's-length.

- In several litigation matters between the IRS and U.S. companies (AEP, Dow Chemical, and Xcel Energy) regarding the interest deduction of policy loans against the corporate-owned life insurance policy, Dr. Zhou consulted client counsel on the corporate finance issues of the insurance policies.

Risk Analysis and Valuation

- In an estate dispute, Dr. Zhou opined on the reasonableness of an over-funded variable annuity in replicating the payoffs under a fixed annuity and estimated the cost savings.
- For a large oil pipeline project in Canada, Dr. Zhou led a project team to analyze the risks and returns of the investment under various scenarios, evaluated the distribution of project's internal rate of returns, and advised the company on regulatory filings before the National Energy Board.
- Dr. Zhou analyzed economic reasonableness of Chicago Clean Energy's cost of equity and capital costs, and presented results to Illinois Commerce Commission.
- For an online gaming company during its settlement negotiation with the Department of Justice, Dr. Zhou reviewed a third-party analysis of the gaming company's ability to pay fines.
- In a merger & acquisition litigation, Dr. Zhou analyzed the transaction premium for a proposed merger of two large U.S. utilities companies.
- Dr. Zhou recently valued a privately-owned C-Corp. that owns, among others, general partnership (GP) interest of a publicly traded energy master limited partnership (MLP), and equity interest in a gas storage joint venture.
- In anticipation of a fraudulent conveyance action involving a large leveraged buyout transaction during the financial crisis, Dr. Zhou led the project team to review several valuation and solvency analyses performed at the time of the transaction.
- For an electricity user consortium in New England considering electricity contract renewal v. generation asset purchase, Dr. Zhou presented market evidence on energy and capacity price forecasts, funding costs, and operational efficiency. He analyzed differences in cash flows under multiple market scenarios to inform considerations of risk.
- For an offshore wind developer proposing to build a 350 MW project off the coast of New Jersey, Dr. Zhou developed a detailed financial model of project funding, operation, and cash distributions to various types of investors (including production tax credit, and the FLIP tax structure), and the pro forma financial statements were used in an application to the state of New Jersey for project grants.
- Dr. Zhou provided due diligence support on regulatory and valuation matters to an Asian sovereign wealth fund in its investment in OnCor energy. On regulatory issues, he analyzed tax treatment of an LLC organization form, allowed rates of return, and investment recovery mechanism. On valuation issues, he reviewed the utility's pro forma financial statements and prepared valuation summaries under various market conditions and regulatory policy changes.
- For Peoples Gas in Chicago, Dr. Zhou reviewed its risk management strategies, recommended hedging policies based on volatility forecasts estimated from NYMEX gas options, and developed proto-type hedging simulation models and performance monitoring metrics.

- For CenterPoint Energy's stranded cost recovery proceeding, Dr. Zhou analyzed whether the market valuation of Texas Genco, CenterPoint's majority-owned subsidiary at the time, reflected the fair value of the generation assets, and whether the company's conservative corporate finance policy and ownership structure at the time enhanced the enterprise value.
- Dr. Zhou worked on several cost of capital cases for both regulated and unregulated businesses. For a major U.S. utility company, Dr. Zhou developed a methodology for estimating cost of capital for different types of electricity generation plants, based on their respective fuel inputs, geographic locations, and operating leverage.
- In various projects, Dr. Zhou developed financial models (discounted cash flow models and real option pricing models) to estimate the value of a project, investment hurdle rate, and asset retirement and replacement decisions. The industries include utilities, energy, and telecommunication.
- In various projects, Dr. Zhou developed valuation frameworks to value tax-favored investment vehicles. They include partnerships, S-Corp., municipalities, MLPs, and life insurance products.

Contract Disputes and Damages

- On behalf of Trans Canada over the interpretation of a long-term power purchase contract clause governing whether "high impact low probability" risks were compensated through a risk premium in the contract price, Dr. Zhou examined the regulatory history in Alberta leading to the contractual arrangements, and assisted another Brattle Principal to interpret the contractual language. The arbitration panel ruled in favor of Trans Canada.
- In a hedge fund redemption and valuation dispute in late 2008 between an investor and the fund management, Dr. Zhou analyzed the fund management's internal net asset valuation (NAV) calculation, valuation discounts under FAS 157, and monthly performance reporting to the investors. The assets under management included thousands of illiquid structured finance products and real estate assets.
- Dr. Zhou assisted Prof. Stewart Myers from MIT Sloan School on an international arbitration matter regarding damages from the government's expropriation of ExxonMobil oil assets in Venezuela.
- In a hedge fund dispute between an equity investor and the fund management, Dr. Zhou analyzed the fund's investment in various structured finance products, financial leverage via repo transactions, portfolio risk management, compliance with the investment guideline, and performance reporting. He assisted counsel for the investor to amend the complaint.
- In a dispute over damages from a prematurely terminated long-term power tolling contract, Dr. Zhou assisted the testifying experts to present evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. Our position was adopted by the arbitration panel.

- For a major U.S. cable TV company, Dr. Zhou analyzed two complex corporate transactions each worth hundred millions of dollar. Both transactions consist of revenue contribution and subsequent transfer of corporate ownership between two affiliated entities (each with a separate tracking stock on the market) at the time. Dr. Zhou investigated the fairness of the terms and conditions of overall transactions.
- Dr. Zhou worked on several Winstar cases, breach-of-contract lawsuits against the U.S. government arising from the savings and loan crisis in the late 1980s. He built pro forma financial models and analyzed thrift financial data, operations, funding, and capital adequacy standards. He supported two experts estimating damages under reliance, restitution, lost profits / expectancy, and mitigation theories.

Miscellaneous

- In MetWest's excessive advisory fee litigation, Dr. Zhou supported a cost accounting expert to analyze the appropriateness of fees charged to mutual fund investors for investment management and related services. He advised the fund advisor and its outside counsel on the relevant measures of profitability, and reviewed and tested the sensitivity of cost allocations to the funds.
- For a U.S. telecom company, Dr. Zhou analyzed the economic impact of a tax-favored dividend repatriation policy on the U.S. economy.
- For a major investor of U.S. wind farms and wind turbine manufacturer, Dr. Zhou and a team of Brattle consultants analyzed the economic impact of the extension of U.S. production tax credit program.
- In an intellectual property infringement case, Dr. Zhou supported a Brattle testifying expert to estimate lost profit damages. He analyzed intra-company financial data for the infringed to estimate the marginal cost and transfer pricing of intermediate products.
- Dr. Zhou co-authored a white paper on behalf of a coalition for competitive insurance rates analyzing the impact on the U.S. property and casualty insurance market of a tax on offshore affiliate reinsurance.
- For a Denmark company with operation in Venezuela, Dr. Zhou reviewed and recommended improvement to the local unit's foreign exchange hedging strategy.
- For a major U.S. telecom company, Dr. Zhou supported two MIT Sloan School professors advising the telecom company about its market penetration strategy in emerging markets and business alliance strategy with local business groups.

Expert Testimony and Trial Experience

Submitted a reply affidavit, joint with Johannes P. Pfeifenberger, et al., on behalf of Alberta Electric System Operator, in Alberta Utilities Commission proceeding #23757 on merchant generation cost of capital, 2019

Submitted an affidavit and a reply affidavit, joint with Johannes P. Pfeifenberger, in PJM's Federal Energy Regulatory Commission proceeding on merchant generation cost of capital, 2018 (Docket No. ER19-105-000)

Submitted three expert reports and testified at trial in an estate dispute involving annuity valuation, 2014

Submitted an affidavit, joint with Johannes P. Pfeifenberger, in PJM's Federal Energy Regulatory Commission proceeding on merchant generation cost of capital, 2014

Publications and Presentations

"The Social and Economic Contributions of the Life Insurance Industry: An Update," 2020, prepared for MetLife Inc., joint with Michael Cragg and Sarah Hamilton.

"How To Assess Accounting Materiality Amid Economic Crisis," Joint with Adrienna Huffman and Chi Cheng, Law360, May 8, 2020.

"Fraudulent Transfers: Cases, Trends and Updates in the 2019 Minefield," The Knowledge Group Webinar, January 16, 2019.

Presentation to Joint Task Force on M&A Litigation, ABA Business Law Section Meeting, Austin, TX, September 15, 2018.

"Examining the Role of Market Price in Appraisal" Parts 1 and 2, joint with Dirk Hackbarth, Law360, September 10 and 11, 2018.

"The Social and Economic Contributions of the Life Insurance Industry: An Update," 2018, prepared for MetLife Inc., joint with David Cummins, Michael Cragg, and Jehan deFonseka.

"Tax Cuts and Jobs Act: Transfer Pricing Implications for Financial Transactions and Financial Services Companies," NABE Transfer Pricing Symposium panelist, July 2018

"Effects of New Tax Law on Capital Structure and Cost of Capital," joint with Dirk Hackbarth, Tax Notes, March 12, 2018.

"Evaluating the Impact of an Offshore Reinsurance Tax," joint with Michael Cragg, Jehan deFonseka, and Lawrence Powell, Tax Notes, February 9, 2017.

"The Impact of Offshore Affiliate Reinsurance Tax Proposals on the U.S. Insurance Market: An Updated Economic Analysis," January 23, 2017, prepared for the Association of Bermuda Insurers and Reinsurers, joint with Michael Cragg, Jehan deFonseka, and Lawrence Powell.

"The Social and Economic Contributions of the Life Insurance Industry," 2016, prepared for MetLife Inc., joint with David Cummins, Michael Cragg, and Jehan deFonseka.

Moderator, "OECD Country-by-Country Data Submissions — A Potential for Misapplication of Big Data," ABA Tax 2016 Joint Fall Meeting, Boston, MA.

"The Interaction of Managerial and Tax Transfer Pricing," 2016, joint with Shannon Anderson, Rand Ghayad, and Michael Cragg, Bloomberg BNA Transfer Pricing Report, Vol. 24, No. 2.

"The Implications of Transfer Pricing in Bankruptcy," 2015, joint with Steven Felgran, Bloomberg BNA Transfer Pricing Report, Vol. 24, No. 17.

"Statistical review of U.S. macronutrient consumption data, 1965-2011: Americans have been following dietary guidelines, coincident with the rise in obesity," May 2015, joint with Evan Cohen, Michael I. Cragg, Jehan deFonseka, Melanie Rosenberg, and Adele Hite, Nutrition, Vol. 31, Issue 5, pp. 727–732.

"Public Disclosure versus Confidentiality in Liquid Fuel Markets," prepared for Flint Hills Resources, LP and Marathon Petroleum Company LP, joint with Evan Cohen, Michael Cragg, and David Hutchings, January 23, 2015.

"Reducing Rate Shocks," joint with A. Lawrence Kolbe and Philip Q Hanser, *Fortnightly Magazine*, June 2013.

"Infrastructure and Rate Structure: Lessening the Shock," joint with Larry Kolbe and Phil Hanser, 2012 NASUCA Annual Meeting (Baltimore, MD), November 2012.

"Control Premiums / Minority Discounts --- Recent Cases and Economic Evidence" at The Knowledge Congress webcast series "Business Valuation Trends Explored in 2012 LIVE Webcast." October 2012.

EUCI Workshops on Utility Financial Accounting, co-taught by Bente Villadsen and Bin Zhou, October 2012 (Denver), May 2012 (Atlanta), and February 2012 (Chicago) (one and half days each).

"Economic Considerations in Litigation against the Credit Rating Agencies," by Bin Zhou and Pavitra Kumar, The Brattle Group, Inc., April 2012.

"State Regulatory Hurdles to Utility Environmental Compliance," by Phil Hanser, Metin Celebi, and Bin Zhou, *The Electricity Journal*, April 2012.

"U.S. Tax Implications of Wind Power Business," presented at U.S.-China Wind Summit 2011, December 2011.

"U.S. Renewable Energy and Transmission Regulation and Investment Opportunities," Judy Chang and Bin Zhou, presented to State Grid Corporation of China (Beijing), September 2011.

"Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM," (with Kathleen Spees, Samuel A. Newell, Robert Carlton, and Johannes P. Pfeifenberger and others), 2011.

"Defining Market Manipulation in a Post-REMIT World," Brattle Discussion Paper, (with Shaun Ledgerwood, Dan Harris, and Pinar Bagci), 2011.

"Risk-Adjusted Damages Calculation in Breach of Contract Disputes: A Case Study*," Journal of Business Valuation and Economic Loss Analysis,* (with Frank C. Graves, Melvin Brosterman, and Quinlan Murphy), 2010.

"The Impact on the U.S. Insurance Market of H.R. 3424 on Offshore Affiliate Reinsurance: An Updated Economic Analysis," (with Michael I. Cragg and J. David Cummins), The Brattle Group, Inc., July 8, 2010.

Litigation Facing the Private Equity Industry *2009 No. 1* (Finance).

"The Impact on the U.S. Insurance Market of a Tax on Offshore Affiliate Reinsurance: An Economic Analysis," (with Michael I. Cragg and J. David Cummins), The Brattle Group, Inc., May 1, 2009.

"Economics of Supervisory Goodwill," (with Stewart C. Myers) *Presented at MIT Sloan School of Management,* The Brattle Group, Inc., March 17, 2003.

"Cost of Capital Estimation for Unregulated Generation: Methodology and Estimates," The Brattle Group, Inc., May 22-23, 2001.

"New Advances in Capital Budgeting for Generation Assets: Survey and Interpretation," *Electricity Power and Research Institute Fall Seminar*, November 14, 2000.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Johannes P. Pfeifenberger**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

Johannes P. Pfeifenberger

Subscribed and sworn to before me, the undersigned notary public, this ___ day of September 2022.

Notary Public

Gerard M. Rooney
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Commission Expires
6/30/2028

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

VERIFICATION

I, **Bin Zhou**, being duly sworn according to law, state under oath that the matters set forth in the foregoing "Affidavit of Johannes P. Pfeifenberger and Bin Zhou on Behalf of PJM Interconnection, L.L.C.," are true and correct to the best of my knowledge, information, and belief.

Bin Zhou 9/27/2022